BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

| | | |
|---|---|---|
| IN THE MATTER OF: | ) | |
| | ) | |
| PROPOSED NEW 35 ILL. ADM. CODE 217, | ) | R01-9 |
| SUBPART W FOR ELECTRICAL GENERATING | ) | P.C. #5 |
| UNITS, AND AMENDMENTS TO | ) | |
| 35 ILL. ADM. CODE 211 AND 217 | ) | |

**NOTICE OF FILING**

To: See Attached Service List

PLEASE TAKE NOTICE that on behalf of the AMEREN CORPORATION, I have filed with the Clerk of the Illinois Pollution Control Board **AMEREN CORPORATION'S POST HEARING COMMENTS,** copies of which are hereby served on you.

AMEREN CORPORATION

By: ______________________
One of their Attorneys

Dated: October 13, 2000

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***THIS FILING SUBMITTED ON RECYCLED PAPER***

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

| | | |
|---|---|---|
| IN THE MATTER OF: | ) | |
| | ) | |
| PROPOSED NEW 35 ILL. ADM. CODE 217, | ) | |
| SUBPART W FOR ELECTRICAL GENERATING | ) | R01-9 |
| UNITS, AND AMENDMENTS TO | ) | (RULEMAKING AIR) |
| 35 ILL. ADM. CODE 211 AND 217 | ) | |

## AMEREN CORPORATION'S POST HEARING COMMENTS

Ameren Corporation ("Ameren"), by and through its attorneys Ross & Hardies, files these post hearing comments on the regulations proposed by the Illinois Environmental Protection Agency ("IEPA") at 35 Ill. Adm. Code Part 217, Subpart W ("Subpart W"). Ameren participated in the two hearings held by the Board on this matter and submitted both the prefiled testimony of Michael Menne, Manager of the Environmental Health and Safety Department (Exhibit 32) and presented the actual testimony of Mr. Menne (T.30-63, 223-230 September 26).[1] These comments are intended to summarize Mr. Menne's testimony and to respond to some of the issues raised during the hearings.

In response to the Board requests during Mr. Menne's testimony, Ameren supplements these comments with two attachments. Attachment 1 is a report "U.S. Gas and Power Supply under the Kyoto Protocol" prepared by Resource Data International for the Edison Electric Institute. Per the Hearing Officer's direction, (T.230, September 26) Ameren is filing the complete report with the Board but will distribute the Executive Summary to the Service List. The report provides information about natural gas supply and demand. Attachment 2 includes Ameren's cost estimates for NOx control strategies at the existing generating facilities to comply with the proposed rules.

**THIS FILING SUBMITTED ON RECYCLED PAPER**

[1] References to the transcript will be by page and date, i.e., T.__, September 26.

Ameren supports the adoption of Subpart W, with the modifications proposed below. Ameren agrees with the IEPA that the USEPA's NOx SIP Call regulations at 63 Fed. Reg. 57356 October 27, 1998 required the state of Illinois to either adopt regulations consistent with the SIP Call or face a forced federal implementation plan. Section 9.9 to the Illinois Environmental Protection Act (415 ILCS 5/99) makes that choice and directs the Board to adopt regulations proposed by the IEPA as necessary to meet the SIP Call. Under these circumstances, the Board has little discretion but to adopt the proposed regulations.

While the adoption of Subpart W may have been mandated by the General Assembly, the Board should understand that the record in support of Subpart W documents that the proposed cap and trade program is more stringent than necessary to achieve several of the individual goals for which these regulations are intended. The IEPA testified that the emission control levels and trading program in Subpart W are more stringent than necessary to support the attainment demonstrations for the Metro East / St. Louis non-attainment area (T.34, August 28) and may be more stringent than necessary to achieve attainment for the Lake Michigan area as well. (T.65, August 28). Ameren believes that attainment for the Metro East / St. Louis non-attainment area will be achieved with a .25 lbs/mmbtu NOx emissions limitation (".25 rule"), and attainment for the Lake Michigan area may be achieved, subject to additional modeling. (T.35, September 26). Further, as Mr. Menne testified, a .25 rule would likely achieve the NOx reductions necessary to protect downwind transport areas, although additional modeling needs to be completed here, as well. (T.35, September 26). While the Board may have little choice but to adopt Subpart W in this proceeding, it should understand that if the NOx SIP call is overturned, the record here does not establish that Subpart W is either necessary or economically reasonable to meet these other goals. This will be especially true if the IEPA proposes, and the Board adopts, the .25 rule in a separate rulemaking.

Ameren also believes that the fixed/ flex allocation system proposed by the IEPA in Subpart W is fair and should be adopted by the Board. Many of the industry witnesses testified that the key element of unfairness in this system is the unrealistic NOx emissions budget for EGUs imposed on Illinois by the USEPA. While the IEPA made positive efforts to adjust the budget upwards, the USEPA used nonsensical growth factors in evaluating generating capacity in Illinois and setting the statewide EGU budget. Many facilities are already operating at a capacity that the USEPA predicted would not occur until 2007. (T.41, September 25; T. 235, September 26; Exhibit 41, p.5). As a result of the USEPA budget decisions, the available allowances are far less than they should be. While court challenges may modify the emissions budget, the IEPA and the Board currently face the prospect of allocating far too few allowances among many different companies.

Despite this daunting challenge, the IEPA proposed an equitable allocation system. The IEPA developed this process only after extensive efforts to reach out to all interested parties. As the IEPA testified, their staff opened the development process to all stakeholders. (T.31-32, August 28). The IEPA held numerous meetings and made substantial efforts to contact different participants, including the existing generators and the new companies seeking to build more capacity in the state. (Id.) At no point in the process was any company or group hindered from discussing their interests or presenting their point of view.

The proposal balances the need to encourage the development of new facilities with the need to provide reliable power from existing base load units. The proposal provides specified allowances to EGUs that commenced operation prior to 1995 because these units provide the base load power necessary to meet the fundamental electrical needs of Illinois consumers. (Exhibit 32, p.6). While new generators may provide additional capacity, primarily to meet peak loads, no evidence was presented to the Board that these new units will provide the needed generating capacity to meet the basic day-to-day demand served by the EGUs in the early years of the program. The Illinois consumer will not be better served by forcing the base load units to remain uncertain as to their allocations until the beginning of each control season or to force these units to purchase all their allowances on the open market. The fixed/flex system provides a sensible phase-in of the allocation process that allows the existing base load units to predict plan upgrades, retrofits and system changes based on known allowances during the initial years of the program.

Even with the set allocations, the operators of many of the EGUs, including Ameren, testified that they plan to incur substantial costs to comply with Subpart W. Because of USEPA's arbitrarily imposed growth factor, and the projected oversubsription in allowances, these companies will have to achieve far greater control levels than the identified .15 lbs/mmbtu NOx emission rate. Mr. Menne testified that Ameren planned to spend an estimated $130 million on its Illinois facilities to meet Subpart W (Exhibit 32, p.5, See Attachment 2) and Mr. Diericx testified that Dynergy would spend over $100 million. (T.234, September 26). Mr. Miller, on behalf of Midwest Generating, testified that his company was already working to reduce NOx emissions at its facilities. (T.170-171, September 26). The costs of these reductions will generally exceed that predicted by the IEPA. (Exhibit 32, p.5; Exhibit 41, p. 6-7).

In contrast, while many of the companies proposing new generation discussed the potential disincentives associated with the proposal, not one of them testified as to actual or projected costs for them to comply with Subpart W, even if that compliance consisted solely of purchasing allowances from the IEPA or on the open market. Further, not one of the new generators testified that they would halt or even reconsider their own developments in light of these disincentives. Plainly, whatever disincentives may be in Subpart W, they are not sufficient to discourage these companies from continuing their Illinois developments. The record demonstrated that the market for generating capacity remains strong. Many of the EGU companies, including Ameren, testified that they were also developing new generating capacity in addition to their existing units and that they were prepared to operate under the proposed rules.

While the fixed/flex rule provides needed stability to the EGUs during the first years of operations, that stability quickly vanishes over the succeeding years. After the first three years of the program, these facilities will begin to compete with other generating companies for allowances on increasingly equal terms and will lose that initial predictability. In an economic equation which is very different than that faced by the new generators, the EGUs must decide whether to spend hundreds of millions of dollars for upgrades for facilities which will not be assured of their allowances after the first three years of the program. Ameren, Dynergy and Midwest testified that they have already decided to invest substantial amounts in their Illinois facilities despite the fact that they will lose their assurance of allocated allowances after three years.

While the fixed/flex rule does provide early advantages to existing generators and are justified to maintain system reliability, they will be quickly lost. The existing generators will pay dearly to continue operating even with the assured allowances and yet are committed to making significant future investments in their Illinois facilities. No testimony was presented that the rule will actually dissuade companies from investing in Illinois and the numbers of permits requested in the last year during which this rule has been under consideration suggests that power companies continue to see the Illinois market as a good place to build generating capacity. The Board should maintain the fixed/flex system proposed by the IEPA.

The Board should also adopt the requirement that allowances for new units should be based on permitted level of operations with a floor of 0.055 lb/mmbtu rather than the .15 lbs/mmbtu control level contained at Section 217.762(a)(2). The IEPA is required to issue permits to new generating facilities based on BACT or LAER even without the adoption of Subpart W. (T.82, August 28). Companies seeking to operate new facilities in Illinois must meet these levels: they cannot choose to operate at higher levels based on the trading program. To allocate emissions based on any level other than that permitted by existing regulations would simply make a gift of the allowances to the new companies. If there were plenty of allowances and incentives were necessary to encourage generating development in Illinois, such a decision might be sensible. The record here however indicates that the opposite is true. The Board should not modify this portion of the Agency's proposal.

Ameren also spoke in favor of the Early Reduction Credits ("ERC") program proposed by the IEPA in its September 26, 2000 Motion to Amend ("Motion to Amend"). Mr. Menne testified as to the importance of ERCs and that they should be used to reward emissions reductions at facilities made within the next two years as EGUs work to comply with Subpart W (T.44-48, September 26). Based on the NOx SIP Call, many companies, including Ameren, plan to make these modifications during 2001 and 2002. (T.170, September 26). Because of this, the Board should continue to allow the credits to be earned during these two years. Further, EGUs should be allowed to use the ERCs during the initial two years of the program, which currently appear to be 2004 and 2005. The Motion to Amend adopted these proposals, although the IEPA added language that the issuance of ERCs must be consistent with whatever modifications the USEPA may make in the compliance supplement pool from which the ERCs are drawn. (Section 217.770) Ameren supports this proposal and requests that the Board adopt it.

Ameren remains concerned with the length of time the IEPA will take to issue the ERCs. While Ameren appreciates the modification made in the Motion to Amend to change the issuance date from May 1 to March 1, Ameren believes that the date should be earlier to allow as much planning as possible. Ameren suggests January 15 as an appropriate date. The IEPA would still have adequate time to process ERC requests under this schedule as sources will have submitted their requests by November 1 of the previous year.

Finally, Ameren wishes to propose certain additional language to clarify the IEPA's proposal. As the IEPA testified at the September 26, 2000 hearing (T.66-68, September 26), many of Ameren's proposals have already been accepted but several were not discussed at the hearing and should be considered by the Board.

The first is a definition of the term "NOx Trading Program." This term, is used frequently throughout Subpart W which specifically mandates that budget units must "meet the requirements of the NOx Trading Program." (Section 217.756(f)(2)). Yet this term is not defined anywhere, including the NOx SIP Call. Ameren believes that it is unfair to require compliance with an undefined program since this could involve not only the specified regulations but also any guidance, published or unpublished opinions, statements or anything else that the IEPA or USEPA might deem included. In order to avoid this result, the Board should define this term so that the regulations with which companies are required to comply are clearly identified. Ameren proposes that the Board add the following definition at a new section designated as 211.4066: <u>For the purposes of Part 217, "NOx Trading Program" means the</u>

requirements of the regulations contained in Part 217, Subpart W including those portions of federal regulations adopted by reference therein."

In communications with the IEPA regarding this proposal change, the IEPA indicated that it had no objection to this proposal other than the concern that future subparts to Part 217 should also be referenced as they are adopted, particularly a planned Subpart U. Ameren would have no objection to including additional pertinent subparts as they are adopted and notes that the Board can modify this definition during future rulemakings for additional subparts.

Ameren also suggested that the Agency clarify Section 217.756(f)(5) both by replacing the language creating personal liability for authorized representatives and also by making it clear that it was not a regulatory or permit mandate that any additional fines imposed "must" be paid without proper enforcement and review proceedings. The IEPA changed the language regarding authorized representatives in its Motion to Amend but did not make the other proposed change. The IEPA acknowledged that they had not considered the second part of Ameren's proposal. (T. 71, September 26). Ameren proposes that the Board modify Section 217.256(f)(6) so that it reads as follows: "In addition to surrendering allowances as provided for in this Section, an EGU that has excess emissions may be subject to liability for any fine, penalty or assessment or to comply with any other remedy imposed under 40 CFR §96.54(d)(3) and the Act.

During the hearings, Ameren questioned the process for modifying the numeric values identified as emission levels in Subpart W. While Section 217.760(c) provides that if the USEPA adjusts the budget, the IEPA will adjust the individual budgets for individual units pro-rata, Ameren believes that it would be more useful and clearer to identify this possibility within the section in which these values are actually set. Ameren proposes that the following language be added as a new Section 217.764(g) either in addition to, or instead of, the language at Section 217.760(c). This language would state as follows: <u>If the USEPA adjusts the total base EGU trading budget for any reason, the Agency shall adjust the total base budget and the specific allowances identified in this Section and in Appendix F pro-rata.</u>

Ameren notes that it is very unusual in Illinois for the Board to adopt a regulation with identified emission values that are subject to modification by the USEPA without a Board rulemaking process. The IEPA included these values as an accommodation to the stakeholders with the understanding that the values could be modified, primarily as a result of the challenge to the USEPA budget brought by some of those stakeholders. Ameren will not contest this portion of the proposal only because of the unique nature of this program. First, the actual emission levels will be determined through a regional trading program and not in an Illinois permit based on Illinois regulations. Second, any modification to these values should be done in accordance with the federal regulatory process well known to the stakeholders and published in the Federal Register. Third, Subpart W provides no discretion to the IEPA other than to pass these modifications through on a pro-rata basis. In no way should Ameren's acceptance of this proposal in this regulation be considered a blanket acceptance of this approach in other regulations. In all other circumstances, values stated in Board regulations should be modified only through further Board rulemakings.

As always, Ameren appreciates the opportunity to testify and present these comments to the Board. This is a difficult proposal imposed by the USEPA which all parties have worked hard to modify for Illinois conditions and the Illinois regulatory system. Subpart W represents the most fair and equitable approach which recognizes the reality of power generation and capacity in Illinois and should be most protective of the environment and the Illinois consumer. Ameren requests that the Board adopt the proposed regulation.

AMEREN CORPORATION

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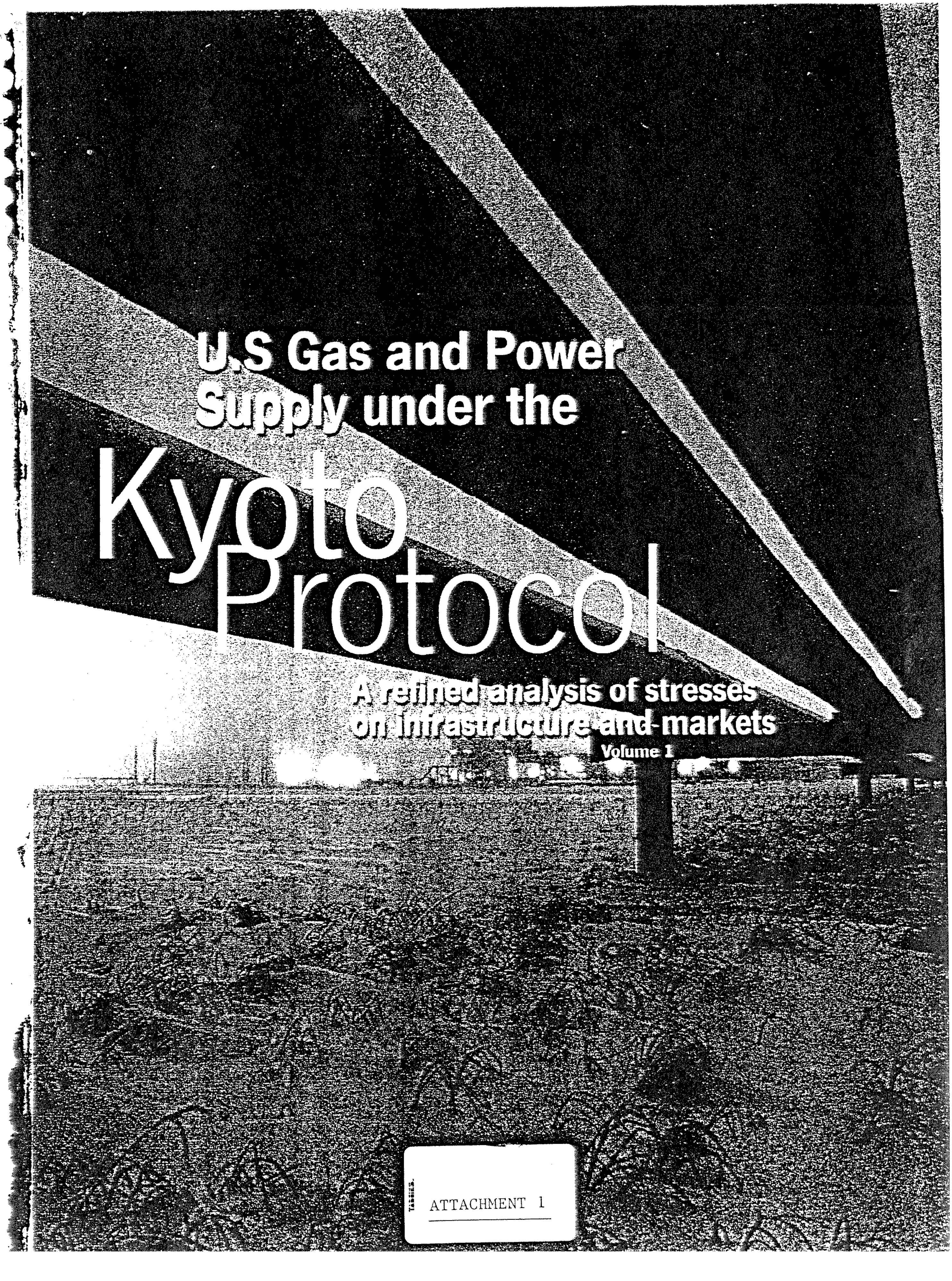

# U.S Gas and Power Supply under the Kyoto Protocol

## A refined analysis of stresses on infrastructure and markets

Volume 1

ATTACHMENT 1

# U.S. Gas and Power Supply under the Kyoto Protocol

Volume I


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September 1999

# U.S. Gas and Power Supply under the Kyoto Protocol

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Since 1981, Resource Data International, Inc. (RDI), unit of Financial Times Energy, has been recognized as the industry leader in electric power and coal consulting and market information in the USA. RDI's client base consists of the world's largest energy resource companies, electric utilities, financial institutions, railroads, and industry consultants. RDI's staff of energy economists and mining engineers provides a broad range of consulting services including strategic planning, acquisition support, market analysis, forecasting, and litigation support. RDI's COALdat, GASdat, POWERmap, and POWERdat databases have provided reliable desktop market and competitor information to the industry for the past fourteen years. RDI authors monthly columns in COAL AGE and PUBLIC UTILITIES FORTNIGHTLY magazine, as well as the online periodical ENERGY insight.

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# U.S. Gas and Power Supply under the Kyoto Protocol

Volume I

## EXECUTIVE SUMMARY

Implementation of the Kyoto Protocol or any similar measure in the United States would require a fundamental shift in the U.S. power supply from coal to gas-fired electricity generation. Natural gas is an important and effective tool for helping the electric industry meet the challenge of emission reductions. However, with up to half of the nation's supply affected, policymakers effectively assume that the natural gas industry can sufficiently respond to an unprecedented rise in demand over a very short time period. The natural gas industry has been a leader in voluntarily reducing greenhouse gas emissions, yet we also recognize the need to develop balanced policies, which limit the potential for major energy price increases. The Edison Electric Institute (EEI) commissioned Resource Data International, Inc. (RDI) to assess what would be required to meet Kyoto emission reduction goals, during the short time frame outlined in the current protocol, by quantifying the level and timing of new gas demand. It is important to point out that there are multiple stress points throughout the gas supply infrastructure that policy makers should recognize as they consider carbon reduction schemes.

Coal-fired power plants currently provide more than half of the U.S. electricity supply, but account for more than 80% of electricity sector carbon emissions, or about 30% of total U.S. emissions. Natural gas as a fuel contains 40% less carbon than coal on an equivalent heat basis, while highly efficient natural gas combined cycle power plants emit up to 60% less carbon than conventional coal-fired plants. Consequently, a shift from coal to gas would be the centerpiece of Kyoto Protocol compliance for the electricity sector.

Even without the Kyoto Protocol, the electricity sector is relying heavily on natural gas to fuel new generating capacity. Gas technology capital costs are at least half that for coal, and gas capacity can be added incrementally where new coal capacity generally requires large initial outlays. These features are especially attractive in the deregulated utility industry. RDI projects that electric sector gas consumption will grow by 100% within the next ten years and that the electricity sector will grow from a 17% share of total gas demand today to 27% by 2010. Driven by electricity, demand for natural gas will expand by 24% overall by 2010. To keep pace with this rapid growth, gas producers, carriers, and distributors will be challenged to expand reserves, infrastructure, and service.

Under the Kyoto Protocol, the gas industry would not only need to meet new electricity demand, but also replace existing coal-fired capacity. Challenges would arise from an array of economic and technical factors that could limit the ultimate success of the effort. These factors include: access to adequate reserves; the deployment of deepwater drilling technology; the availability of drilling rigs; timely capital investment decisions for pipeline expansion; pipeline construction with little local opposition; continued open access to Canadian resources; and a significant and coordinated gas industry effort to maintain unprecedented growth rates for several consecutive years.

The risks associated with these factors should decrease over time – but time is in short supply under the proposed Kyoto Protocol. As drafted, the protocol would require signatory countries to meet their designated reduction targets on average during the years 2008-2012, with a demonstration of reasonable progress prior to 2008. Consider that the President has not yet submitted the protocol to the Senate for advice and consent, let alone implementation.

Although natural gas is one of the more dynamic and market-oriented industries in the energy sector, factors relating to land-use, such as gas exploration and pipeline projects, are especially time-sensitive areas. The approval process for these activities tends to be political and highly regulated at various government levels. Not surprisingly, land-use activities are often slow to respond to changing market conditions and could prove troublesome for the industry's efforts to meet demand under the proposed Kyoto Protocol timeline.

The unfavorable outcome of any of the factors listed above, especially the time-sensitive factors, would be problematic and could result in gas and electricity price spikes. Carbon costs would effectively remove coal and oil as alternatives to gas, while nuclear retirement and dam removal could further erode alternatives to gas. The only ceiling on gas would be higher cost non-hydro renewables, energy efficiency investment or simply reduced consumption. Production costs would also facilitate higher gas prices, given the additional effort required to draw gas from deep reserve sources and to fund the necessary production and transmission infrastructure.

Taken together, high demand growth, limited alternatives, and rising supply costs would drive natural gas prices to almost one-third higher than business-as-usual projections for 2010. This does not account for the cost of carbon that would be paid by end-users. Consumers faced with surging gas prices would have few alternatives outside of energy conservation. Gas-fired power plants, as the marginal supplier in the open wholesale electricity market, are increasingly setting electricity prices throughout the U.S., and this convergence between gas and power prices would accelerate and intensify under Kyoto Protocol implementation. RDI projects that non-firm wholesale electricity prices, reacting to robust gas prices as well as carbon costs, could rise by a factor of three under Kyoto.

Additional uncertainties center on the rules that would implement the Kyoto Protocol itself. Specifically, the flexibility afforded affected parties to trade carbon emission credits would directly influence the costs and risks of compliance. The United States favors a liberal, liquid international carbon trading market, while the European Union and others favor a more rigid market in which limits would be applied to trading for compliance. This study and others find that the costs of compliance would be lower with a liberal market and higher with a rigid market. To conduct this analysis, RDI assumed four trading scenarios:

**Base Case** – Business-as-usual, no implementation of the Kyoto Protocol.

**Low Case** – Low domestic carbon reductions required, as affected U.S. sources freely acquire overseas carbon credits and offsets.

**Moderate Case** - Moderate domestic carbon reductions required, as affected U.S. sources acquire overseas carbon credits and offsets under limited restrictions.

**High Case** - High domestic carbon reductions required, as affected U.S. sources are limited in acquiring overseas carbon credits and offsets.

The Low, Medium, and High Cases are based on the carbon prices and other underlying assumptions from the domestic carbon reduction scenarios as presented in the U.S. Energy Information Agency's 1998 Kyoto Protocol study.

The following conclusions and key findings from this study's analyses of gas demand, supply, transmission, pricing, and regional impacts are based on the case descriptions above. In sum, these key findings highlight the *simultaneous* and *cumulative* impacts that compliance with the Kyoto Protocol would place on U.S. natural gas and power markets.

**NATURAL GAS DEMAND**

U.S. natural gas consumption is poised to climb to unprecedented levels, driven by electric generation demand, even without implementation of the Kyoto Protocol. Total annual U.S. consumption currently totals about 22 trillion cubic feet (Tcf) and is anticipated to reach a 30 Tcf threshold by 2015 under Base Case conditions. Implementation of the Kyoto Protocol would push demand beyond these already ambitious levels, led by wholesale shifts away from coal-fired electric generation and toward gas-fired technologies. **Where the fleet of coal plants to be displaced was built over the course of five decades, the electric sector would have less than ten years to build replacement gas-fired capacity.** Key findings include:

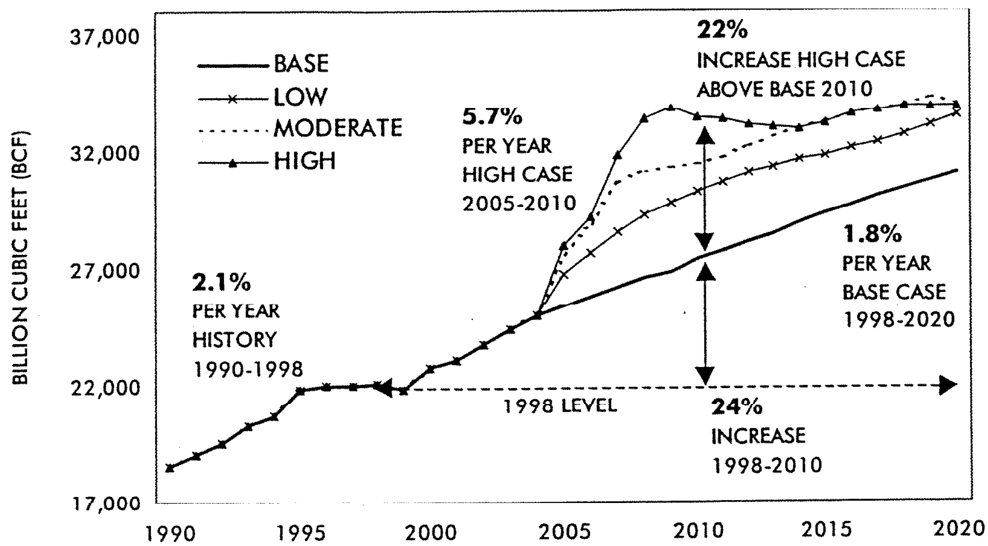
- Gas will provide a projected 25% of the U.S. generation mix in 2010 under our Base Case, while coal will provide 50%. Gas would rise to 31% and coal would fall to 42%of the mix under the Low Case, while gas would rise to 55% and coal would slip to 13% under the High Case.

- Electric sector natural gas demand is projected to increase by 100% under our Base Case by 2010, to become the second largest gas-consuming sector next to the industrial sector. In all of the Kyoto cases electric generation sector becomes the largest end-user of gas by 2008. The Low Case demand would stand at 40% and High Case demand would stand at 118% over our Base Case in 2010.

- Led by the electric sector, total Base Case U.S. gas demand will grow by a projected 24% between 1998 and 2010 and 36% by 2015, reaching a 30 Tcf threshold. Demand under the Low Case would reach the 30 Tcf threshold by 2010, and would arrive at 30 Tcf under the High Case by 2007.

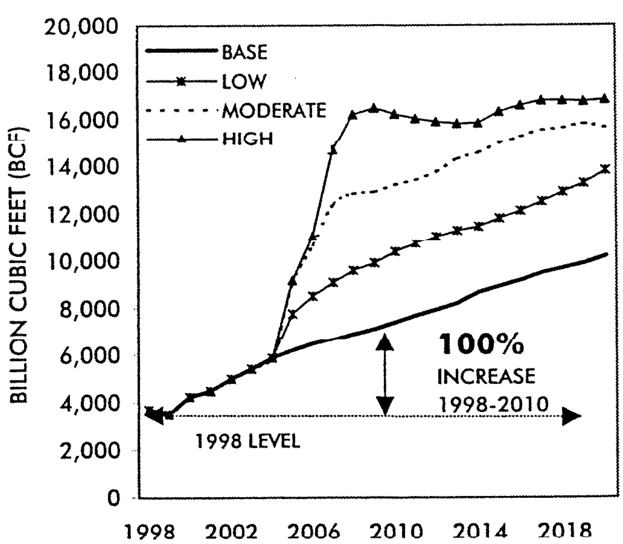
- Gas demand in other sectors would fall dramatically in the Kyoto Protocol cases, as massive increases in generation demand would cause higher prices that drive down gas consumption. High Case residential and commercial demand in 2010, for example, would fall to 24% below our Base Case.

**U.S. NATURAL GAS DEMAND, 1990 – 2020, BASE CASE AND KYOTO CASES**
FIGURE ES-1

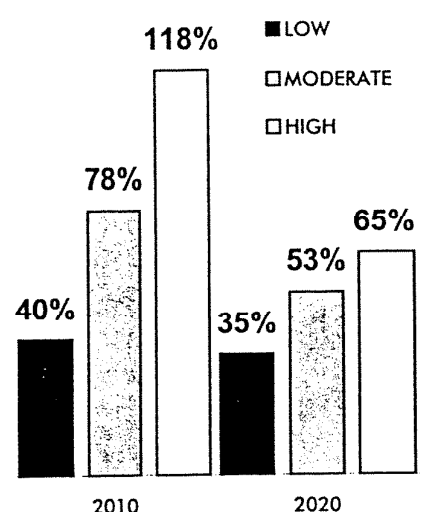



SOURCE: RDI, HISTORY EIA

**U.S. ELECTRIC GENERATION GAS DEMAND, 1990 – 2020**
FIGURE ES-2




**% INC. U.S. ELEC. GAS DEM. ABOVE BASE**




SOURCE: RDI

### NATURAL GAS SUPPLY

Gas supply is a critical question for Kyoto Protocol compliance. The North American natural gas reserve base is adequate to meet even High Case demand through 2020, but achieving the necessary levels of production in the timeframe required would be questionable. **The industry would need to sustain 5% annual growth rates for three consecutive years, 2005-2007, where growth has been 1% or less per year during the 1990s – and the lower 48 states would be called upon to increase High Case production beyond any single year increase on record.** Further, access to the reserve base itself is in question given the need for environmental trade-offs and continued technological advancement. Key findings include:

- Gas deliverability in the Moderate and High Cases would need to grow by 5% per year for three consecutive years, 2005-2007. Average production growth in the 1990s has been less than 1% per year.

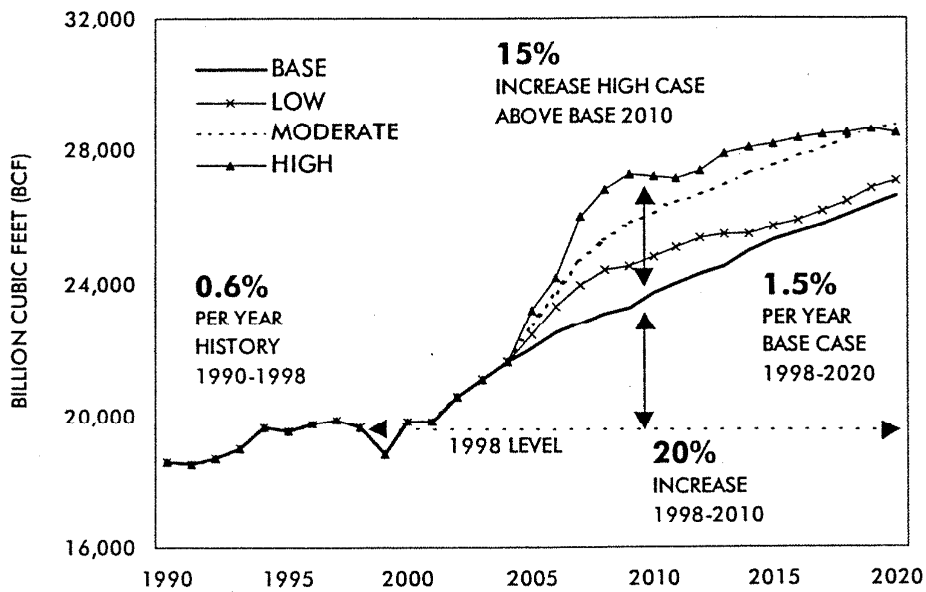
- Canada and the Gulf of Mexico would provide half of the incremental gas supply under the Kyoto Protocol cases. The primary sources of supply would be pushed into two supply basins, lessening diversity of supply and increasing risk of supply interruptions. These regions have similar shares of growth under each of the cases, but the risk potential is exacerbated under Kyoto, because volumes increase substantially.

- The Kyoto Protocol could force difficult environmental trade-offs. Much of the gas reserve base exists in or near environmentally sensitive offshore and wilderness areas for drilling.

- Annual well completions will need to increase by as much as 33% by 2010 to reach projected Base Case production levels. Kyoto Protocol implementation would force an additional 19% increase in well completions above Base Case levels in 2010.

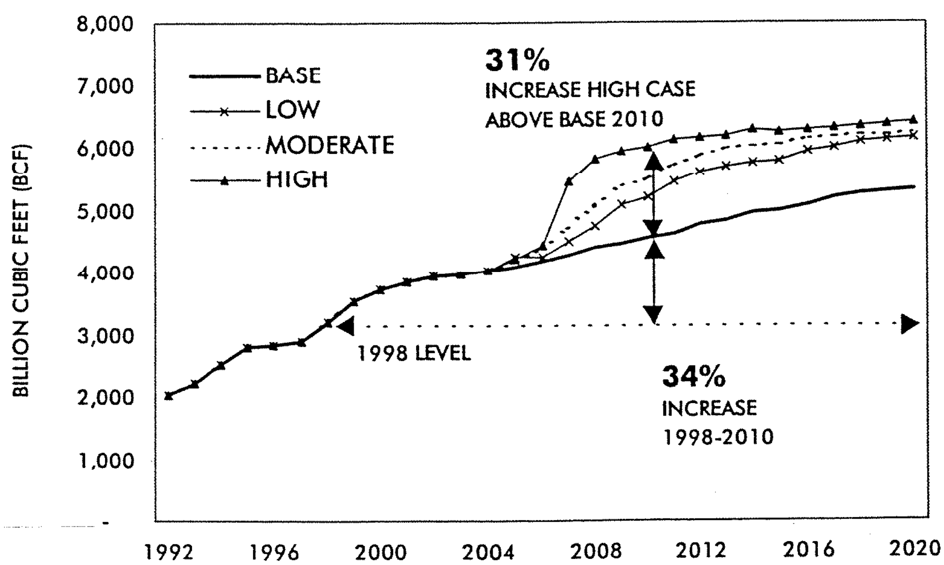
- U.S. wells are depleting at an increasing rate, requiring accelerated development of new wells to maintain existing production levels. This growth of the "decline rate" will increase the burden and stress of expanding production under our Base Case and the carbon reduction cases.

**U.S. LOWER 48 NATURAL GAS PRODUCTION, 1990 - 2020**
FIGURE ES-3




SOURCE: RDI, HISTORY EIA

**CANADIAN GAS IMPORTS**
FIGURE ES-4




SOURCE: RDI

**NATURAL GAS TRANSMISSION**

Kyoto Protocol implementation would present a unique shock to gas markets. **There is no historical parallel to the scale and focus of expansion that would need to be undertaken on the North American pipeline system in such a short time frame.** The availability of construction materials and labor, regulatory and environmental delays, and market dynamics would make adding pipeline capacity under the Kyoto Protocol timeline a daunting challenge. The bulk of this expansion burden would fall on the electricity sector, which would become the largest consumer of gas under the Kyoto Protocol. Generating companies could be faced with making direct investments or entering into long-term transmission agreements to baseload the investment. Key findings include:

- More than 24,000 miles of additional pipeline would need to be laid in the U.S. in the High Case between 2005-2010 compared to 12,000 miles in our Base Case. Only 15,000 miles of pipeline were constructed between 1990-1998.

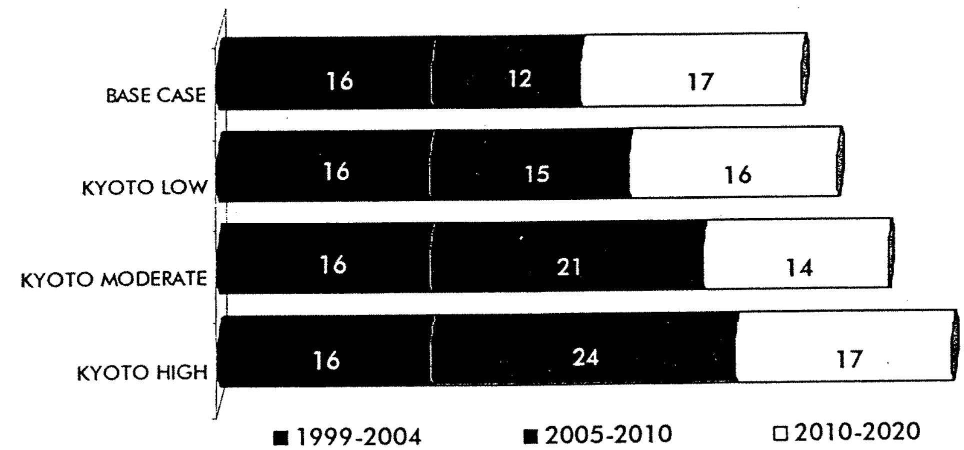
- Peak-year requirements for additional capacity of more than 7,000 miles of pipe per year would force construction levels to three times the current industry average of 2,000 miles per year.

- Landowner opposition, regulatory hurdles, and contractual issues have slowed pipeline construction in recent years. Such delays could not be tolerated in the tight timeframe for Kyoto Protocol implementation and would jeopardize U.S. compliance and gas deliverability.

- As the largest and fastest growing gas consuming sector, electric generators would likely be forced to finance pipeline expansions under the Kyoto Protocol. Generation companies reluctant to commit to firm contracts could delay timely pipeline construction.

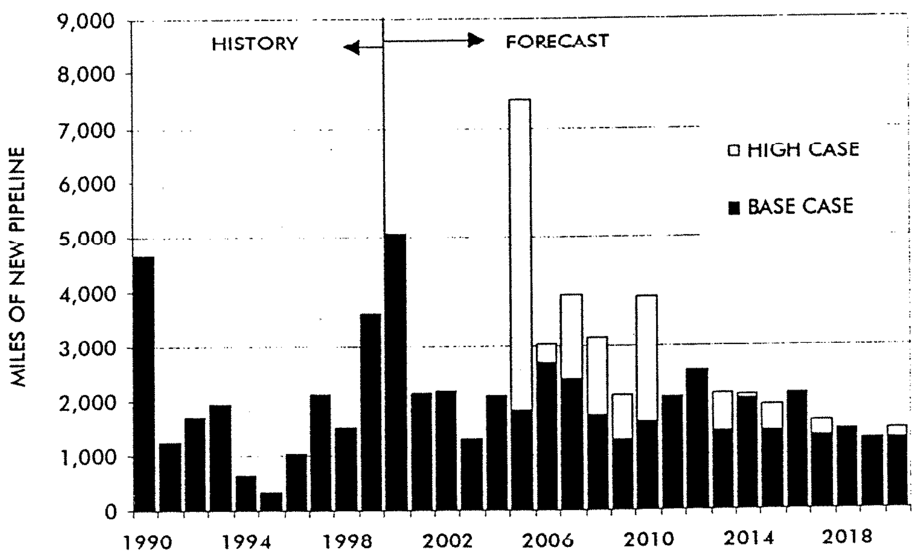
- The electric sector shift to using gas for baseload generation under the Kyoto cases would undermine the seasonal transportation flexibility afforded by gas storage, because year-round pipeline utilization is higher. The loss of this flexibility would amplify pressures for pipeline expansions.

**U.S. CUMULATIVE PIPELINE MILEAGE BY TIME PERIOD AND CASE**
FIGURE ES-5. THOUSANDS OF MILES OF PIPELINE CONSTRUCTION




SOURCE: RDI

**MILES OF PIPELINE CONSTRUCTION PER YEAR – BASE CASE AND KYOTO HIGH**
FIGURE ES-6




SOURCE: RDI

## NATURAL GAS PRICES

A growing body of analysis points to vastly higher fuel and power prices under any Kyoto Protocol compliance scenario. This study adds to that analysis by finding that natural gas prices under the Moderate and High Cases would rise by about one-third above the Base Case in 2010, without considering the cost of carbon associated with gas combustion. Wholesale non-firm electricity prices would rise by a factor of three in the High Case. **Therefore, compliance with the Kyoto Protocol would be not only difficult to achieve, but also very costly – especially to consumers.** Key findings include:

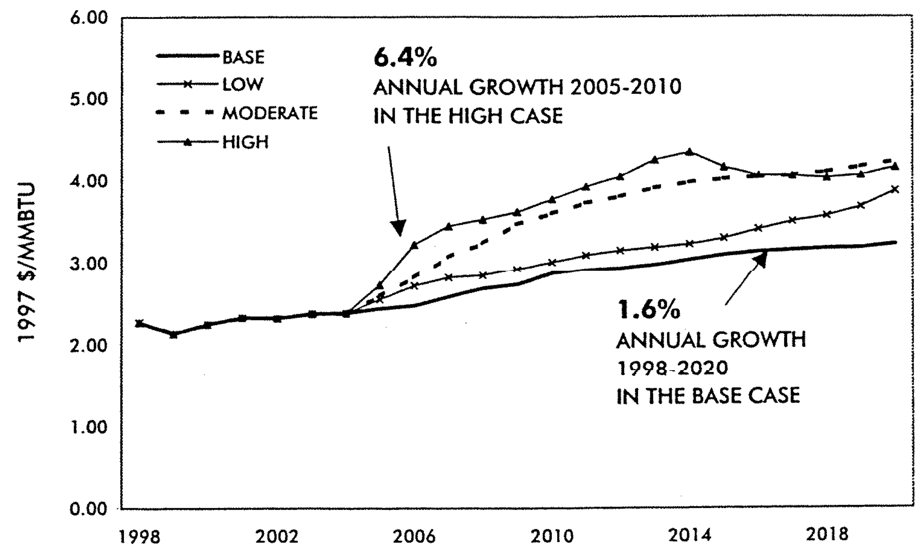
- U.S. average annual prices for natural gas delivered to power plants are forecast to escalate by 2% per year through the forecast period. Prices reach $2.86 per million Btu (mmBtu) in constant 1997 dollars by 2010 in the Base Case. High and Moderate Case market dynamics would force prices to levels 26% to 32% above the Base Case in 2010. These price projections do not include the cost of carbon credits.

- Gas prices at Henry Hub would increase in the Kyoto cases as the costs of gas production climb. Beginning in 2005 gas prices are forecasts to rise by more than 6% per year, climbing past $3.00/mmBtu by 2010 of the Moderate and High Cases. In the Base Case gas prices at Henry Hub are forecasted be $2.40 mmBtu in 2010. Annual growth is projected to increase at 1.2% per year from 1998 to 2020 in the Base Case.

- Natural gas prices drive electricity prices under all of the scenarios, including the Base Case. RDI projects electricity prices to rise by 22% between 1998 and 2010 under the Base Case, but are 187% and 120% higher than the Base Case under the Moderate and High Cases.

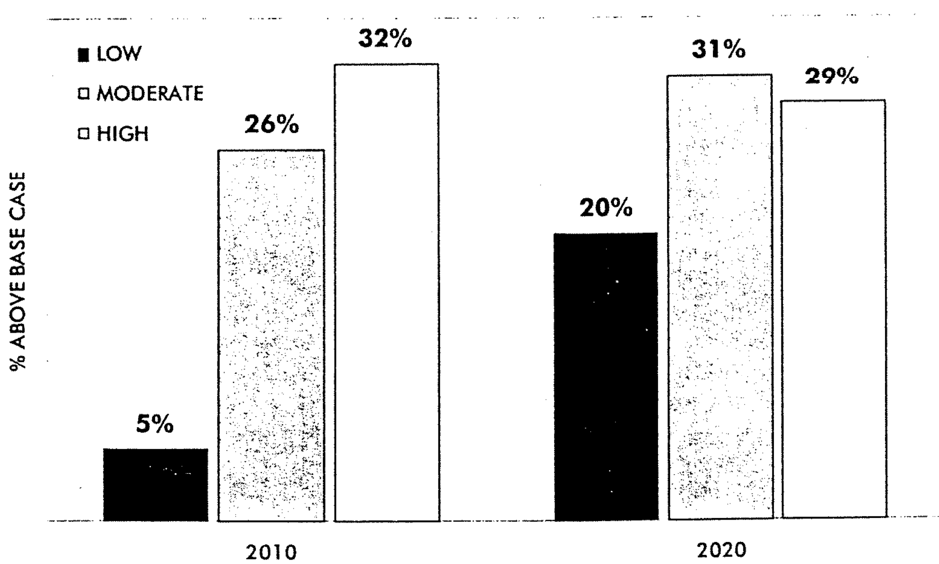
- Gas demand increases on the scale presented in the Base and Low Cases appear to be achievable with moderate increases in gas price. In the more stringent carbon reduction cases, prices rapidly climb as more expensive portions of the gas supply curve are tapped to meet demand requirements and new transmission infrastructure raises shipper costs.

**PROJECTED NATURAL GAS PRICES DELIVERED TO POWER PLANTS, 1998-2020**
FIGURE ES-7




SOURCE: RDI

**DELIVERED TO POWER PLANT PRICE INCREASES ABOVE THE BASE CASE IN 2010 AND 2020**
FIGURE ES-8




SOURCE: RDI

## REGIONAL IMPACTS KEY FINDINGS

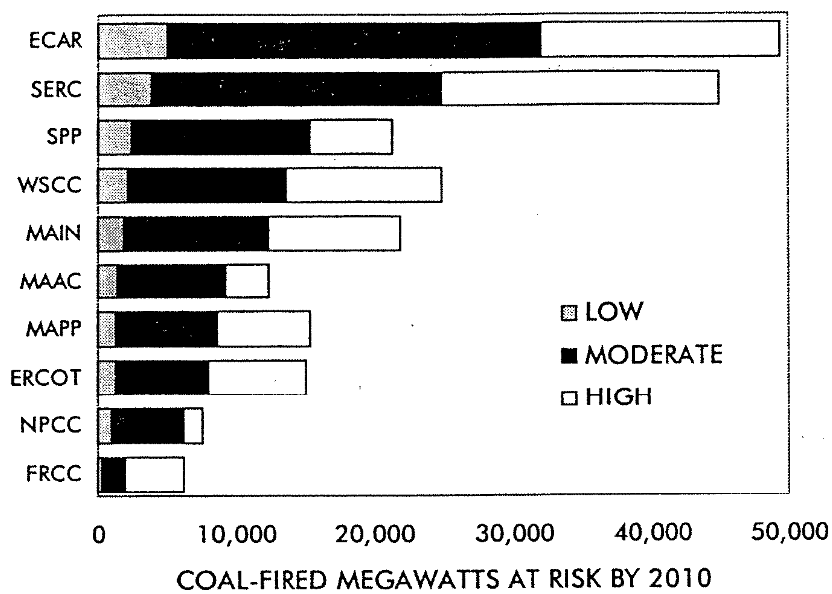
Implementation of the Kyoto Protocol under any of the scenarios examined by RDI would require a substantial turnover and replacement of U.S. electricity generation capital stock and a dramatic increase in the consumption of natural gas – and all within ten years. Furthermore, the effects would not be uniform across the country. While all areas would be affected, some would likely replace a sizeable portion of their generating capacity and dramatically expand pipeline capacity. **The ECAR and SERC regions would become the largest consumers of gas.** Key findings include:

- By 2010, the ECAR and SERC regions of the North American Electric Reliability Council (NERC) would idle at least 25,000 MW of coal-fired generation capacity in the Moderate Case and 50,000 MW in the High Case. RDI projects that total coal-fired capacity at risk in the U.S. would amount to at least 130,000 MW in the Moderate Case and 220,000 MW in the High Case. Existing coal-fired capacity stands at approximately 315,000 MW.

- ECAR would grow from among the lowest gas-consuming regions to become the third largest gas-consuming region by 2010 under the Kyoto cases. RDI projects that the ECAR gas-fired generating capacity will reach 16,925 MW under the Base Case, but would expand 88% further, to 29,924 MW, under the High Case.

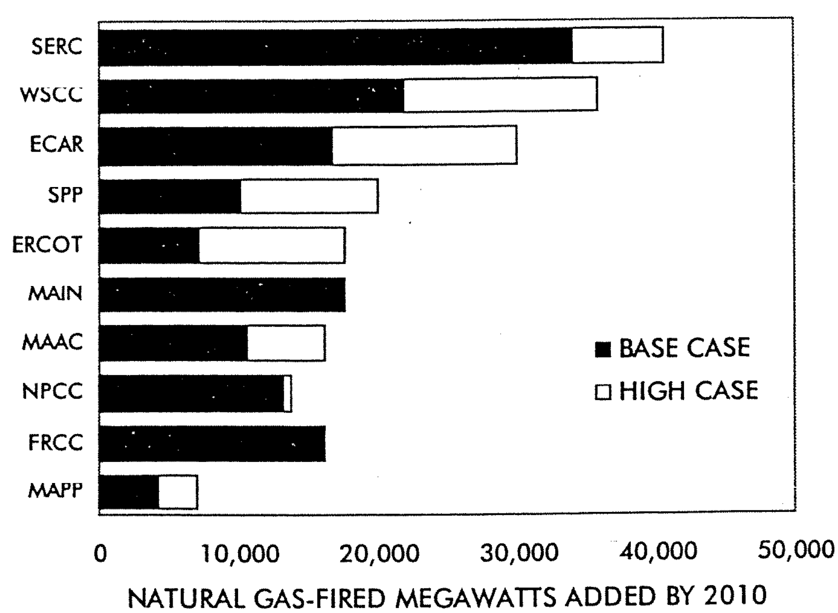
- In 1998, only ERCOT consumed more than 1 Tcf in total gas demand. By 2010, RDI projects that SERC and WSCC will also exceed 1 Tcf each under the Base Case. However, every region but MAPP would exceed 1 Tcf under the High Case in 2010, and four regions would exceed 2 Tcf each.

**COAL POWER AT RISK, 2010 - MODERATE AND HIGH CASES**
FIGURE ES-9




SOURCE: RDI

**NEW GAS-FIRED CAPACITY, 2010 - BASE CASE AND HIGH CASE**
FIGURE ES-10




SOURCE: RDI

# Introduction

## STUDY SCOPE

The Kyoto Protocol, if implemented in the United States, would create tremendous stresses on all segments of the economy, but particularly on natural gas, coal, and electricity markets. Increased reliance on lower emitting natural gas would be central to any near-term carbon reduction strategy for the electric utility industry.[1] Yet, questions persist regarding the ability of the natural gas industry to respond seamlessly to the large demand increases that would follow Kyoto Protocol implementation. To address these questions, the Edison Electric Institute (EEI) commissioned Resource Data International, Inc. (RDI) to quantify gas demand under the Kyoto Protocol; to assess the adequacy of natural gas reserves, production, and transmission capacity; and to project gas price and regional impacts.

Contrary to the general perception, natural gas reserves do not provide the most useful indication of the gas industry's ability to meet growing demand. Rather, reserves are merely the starting point in a complex infrastructure chain that consists of reserve exploration, production, gathering, processing, transportation, storage, distribution, and regulatory links. Each link must expand in concert to meet growing demand, a factor that would be complicated by dramatically steep growth and a tight timetable under the Kyoto Protocol. Further, the breakneck pace of expansion for Kyoto Protocol compliance would leave little to no excess capacity, such that each link would be required to operate at peak levels indefinitely. Failure by any link of the supply chain to expand and operate at levels consistent with demand could negatively impact the national carbon reduction strategy, the operation of gas and electricity markets, and even the national economy.

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[1] "Carbon" as used in this study reflects all greenhouse gases on a carbon-equivalent basis.

This study consequently examines the full length of the North American natural gas supply chain and the effort required to meet projected Kyoto Protocol demand in the less than ten years available to reach compliance, with a focus on the electricity sector as the primary driver of new demand. Even outside of the current proposed schedule for compliance, this study provides an understanding of the complications that would attend a less than ten-year planning horizon.

**CARBON REDUCTION SCENARIOS**

Great uncertainty surrounds the potential implementation of the Kyoto Protocol. Perhaps the greatest area of uncertainty would be the scope and nature of any international carbon trading and offset regime that might eventually be agreed upon. The United States favors broad flexibility in trading emissions and offsets both among Annex I nations and among Annex I and non-Annex I nations.[2] However, other nations are less enthusiastic, such that many of the trading proposals to date would impose a bureaucratized and rigid system. The European Union, for example, has proposed that trading be limited to no more than about 50% of a nation's carbon reduction requirement. Whatever form any final trading regime might take, it will be critical to the economic outcome of carbon reduction in the U.S.

To explore the level of uncertainty flowing from the potential range of trading regimes, this study examines a number of scenarios based on U.S. net domestic carbon reductions. That is, although the Kyoto Protocol calls for the U.S. to reduce emissions to 7% below 1990 levels, the acquisition of offshore carbon credits and offsets could alter the actual, or net, domestic reductions required. For consistency of comparison, RDI and EEI selected three net domestic reduction scenarios based on analyses by the U.S. Energy Information Agency (EIA) in its own modeling of the Kyoto Protocol.[3] Each of these scenarios, in addition to our Base Case, is described below.

---

[2] Annex I nations include the U.S., Canada, the European Union, Australia, New Zealand, and Japan, and nations in Eastern Europe and the Former Soviet Union. Emissions from the non-OECD nations are lower than the 1990 baseline as the result of economic contraction in their transition to market-based economies. These nations could sell surplus carbon credits under an international trading scenario. Non-Annex I nation, i.e., developing countries, could participate in the Clean Development Mechanism.

[3] Energy Information Agency, Office of Integrated Analysis and Forecasting, U.S. Department of Energy. *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity* (SR/OIAF/98-03). October 1998.

Base Case: Assumes business-as-usual, with no national or international effort to reduce carbon emissions. Demand growth assumptions derived from EIA model. Also assumes full implementation of new EPA air quality regulations at coal-fired power plants.

Low Case: Assumes that a substantial number of carbon credits and offsets acquired from abroad under a liberal trading regime lower the U.S. net domestic carbon reduction effort to 24% above 1990 levels. This case is based on the EIA +24% scenario.

Moderate Case: Assumes that carbon credits and offsets acquired from abroad lessen the U.S. net domestic carbon reduction effort to 9% above 1990 levels. This case is based on the EIA +9% scenario and assumes an active international trading regime.

High Case: Assumes that certain offsets result in a high U.S. net domestic carbon reduction effort to 3% below 1990 levels. This case is based on the EIA -3% scenario and assumes a rigid international carbon-trading regime.

## METHODOLOGY

To conduct this study, RDI utilized an integrated power and natural gas market modeling system to project gas and power demand, fuel and power production costs, generating resource mix, generating capacity additions, and natural gas production and transmission capacity additions. The system yields market-clearing results across both the natural gas and electric sectors for each carbon-reduction scenario and our Base Case.[4]

Key modeling assumptions are drawn from the EIA Kyoto Protocol report, including those for average annual growth in electricity demand and generation from non-hydroelectric renewable generators, and RDI's Base Case modeling results have been calibrated to the EIA Reference Case. Correspondence to the EIA work positions this study to build on that prior work and is intended to focus review of this study on its findings, rather than on its assumptions.

Differences in assumptions between this study and the EIA work include nuclear retirement projections and the implementation of new air quality regulations. Our Base Case assumes that nuclear generation capacity decreases during 1998-2020 with the expiration of many 40-year nuclear operating licenses. Over 13,000

[4] See Volume II of this study for a more complete description of the RDI modeling system.

megaWatts (MW) of nuclear capacity are retired by 2010, and almost 20,000 MW are brought off-line by 2020. These are conservative assumptions compared to the EIA study. The EIA assumes 23,000 MW retired by 2010, and 56,000 MW by 2020. In the Kyoto cases, all available nuclear units are life extended through 2020.

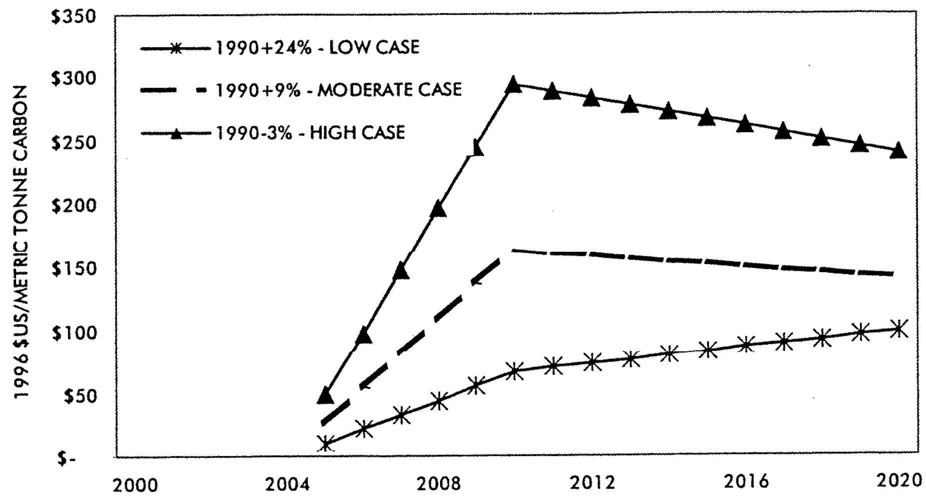
RDI's modeling also assumes effects from compliance with environmental regulations at coal-fired power plants. These include acid rain regulation under the Clean Air Act Amendments of 1990, new national ambient air quality standards (NAAQS) for fine particulate matter and ozone, ozone transport rules under the Ozone Transport Commission (OTC) and the EPA $NO_X$ SIP Call, and new regional haze rules. These regulations effectively require the installation of emission controls for sulfur dioxide ($SO_2$) and nitrogen oxide ($NO_X$). A number of higher cost plants might retire because they cannot economically justify the capital investment. Compliance actions are scheduled to take effect between 1999 and 2007.[5] EIA modeling accounts only for Phase II acid rain compliance.

RDI utilized carbon price projections taken from the EIA work to implement the carbon reduction cases, as described above, for the electricity sector. See Figure 1. For example, in the year 2010, the RDI modeling system imposes a $160 cost for each metric tonne of carbon emitted under the Moderate Case by individual electric generators. This additional cost re-orders the economic dispatch of plants to shift baseload generation to gas and away from coal. Increased gas demand for generation iterates through the gas component of the modeling system to drive new gas production and infrastructure expansions, as well as price changes. This shift to gas implicitly reduced carbon emissions. See Figure 2.

Currently about 86% of $CO_2$ emissions from the U.S. electric generation sector comes from coal-fired power plants. At the carbon prices utilized in the study carbon emissions would decline from 565 million metric tons (MMT) in the Base Case in 1998 to 511, 362, and 371 MMT in 2020 for the Low, Moderate and High cases, respectively. These results are in line with those of the EIA report.

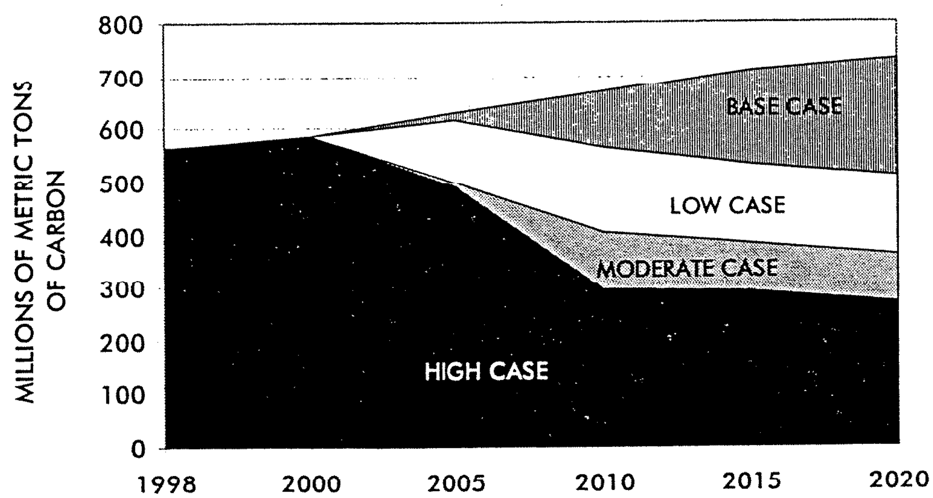
[5] Uncertainty surrounds many of these regulations. Fine particulate matter compliance could start between 2007 and 2014. Further, a federal Court remanded the fine particulate matter and ozone NAAQS to EPA during May 1999, and the 22-State SIP Call could face a court hearing toward the end of 1999.

**EIA CARBON PRICE PROJECTIONS BY SCENARIO**
FIGURE 1




SOURCE: EIA

**CARBON EMMSSIONS FROM ELECTRIC GENERATORS, 1998-2020**
FIGURE 2




SOURCE: RDI

## ORGANIZATION

This study consists of two volumes. Volume I focuses on the stresses of Kyoto Protocol compliance that would be particular to the natural gas industry, and assesses the ability of the gas industry to respond to a dramatic realignment of energy markets. Sections are divided between gas demand, supply, transportation, pricing, and regional impacts. Volume II provides detailed modeling outputs for both the natural gas and electricity markets, as well as a detailed description of RDI's power and natural gas modeling system.

# Natural Gas Demand

## INTRODUCTION AND KEY FINDINGS

U.S. natural gas consumption is poised to climb to unprecedented levels, driven by electric generation demand, even without implementation of the Kyoto Protocol. Total annual U.S. consumption currently totals about 22 trillion cubic feet (Tcf) and is anticipated to reach 30 Tcf by 2015 under Base Case conditions. Implementation of the Kyoto Protocol would push demand beyond these already high projected levels, led by wholesale shifts away from coal-fired electric generation and toward gas-fired technologies. Key findings include:

- Gas will provide a projected 25% of the U.S. generation mix in 2010 under our Base Case, while coal will provide 50%. Gas would rise to 31% and coal would fall to 42%of the mix under the Low Case, while gas would rise to 55% and coal would slip to 13% under the High Case.

- Electric sector natural gas demand is projected to increase by 100% under our Base Case by 2010, to become the second largest gas-consuming sector next to the industrial sector. In all of the Kyoto cases electric generation sector becomes the largest end-user of gas by 2008. The Low Case demand would stand at 40% and High Case demand would stand at 118% over our Base Case in 2010.

- Led by the electric sector, total Base Case U.S. gas demand will grow by a projected 24% between 1998 and 2010 and 36% by 2015, reaching a 30 Tcf threshold. Demand under the Low Case would reach the 30 Tcf threshold by 2010, and would arrive at 30 Tcf under the High Case by 2007.

- Gas demand in other sectors would fall dramatically in the Kyoto Protocol cases, as massive increases in generation demand would cause higher prices that drive down gas consumption. High Case residential and commercial demand in 2010, for example, would fall to 24% below our Base Case.

**OVERVIEW**

Natural gas demand is divided between industrial, residential and commercial, and electric generation consumers. While the industrial sector currently accounts for the largest share of U.S. demand at 37%, it will likely be challenged by the electric generation sector within the next 11 years, assuming Base Case conditions. Electric generators today consume 17% of all gas in the market, but are projected to account for 27% by 2010. This rapid growth in Base Case electric sector consumption sets the stage for tremendous stresses under even greater growth with the Kyoto Protocol.

This growing electric sector gas demand is expected to lead to higher prices. Pressures attendant with these higher prices could cause the residential and commercial sector to invest in end-use efficiency, relocate heavy manufacturing to offshore locales, or otherwise reduce their consumption.

**ELECTRIC SECTOR DEMAND**

Falling capital costs for gas-fired generating technologies, in conjunction with utility restructuring, favor natural gas as the fuel of choice for meeting new electricity demand. Low capital costs per kiloWatt of capacity and the modularity of gas turbines limit investment exposure, a key concern in the deregulating electric utility industry. Electric generating companies are, in fact, relying on natural gas-fired power plants for almost all of their new capacity requirements. At the same time, generating companies rely on existing coal-fired capacity to meet more than half of their demand. **Under the Kyoto Protocol, these companies would build gas plants to not only meet new demand, but also to replace coal-fired capacity.**

**U.S. Generation Mix** Compliance with the Kyoto Protocol would force a wholesale shift from coal-fired to gas-fired electric generation. Coal plants currently provide more than half of the U.S. electricity supply, but account for more than 80% of electric sector carbon emissions. Natural gas is 40% lower in carbon content than coal on an equivalent heat basis, and efficient combined cycle gas generators emit 60% less carbon than coal plants. Therefore, the imposition of a carbon cost would make existing coal-fired generation more expensive than new gas-fired generation, forcing a shift in the U.S. generation mix.

Across each of the carbon reduction scenarios and over time, natural gas is projected to fuel a larger portion of the generation mix. In the Moderate and

High Cases, natural gas generation would supply 50% of the U.S. generation market by 2010 and would contribute more than 60% by 2020. This compares with a 25% market share in 2010 under our Base Case and a current share of about 15%. Offsetting the rise in gas generation in the Kyoto cases would be a decline in coal generation. High Case coal generation is projected to plummet to 13% of the generation mix by 2010.

Currently, greater than 50% of the nation's electricity comes from coal power. In the Base Case, coal generation contributes 50% of the supply in 2010. Nuclear generation retains an 18% share of the market in all of the Kyoto cases, but declines to 14% of the generation mix in our Base Case. Renewable energy sources fill about 10% of the generation mix by 2020 in the High Case. See Figures 3A and 3B on the following pages.

At the same time, higher prices would serve to lower overall electricity demand and generation, somewhat reducing the amount of gas required for meeting new demand. Projected generation in 2010 of 4.1 million megaWatt-hours (MWh) would slip to 4.0 million MWh under the Low Case, 3.8 million MWh under the Moderate Case, and 3.5 million MWh under the High Case. These cases would be 3%, 7% and 15% lower than the Base Case, respectively, such that shifts within the generation mix would occur within a smaller pie. See Table 1.

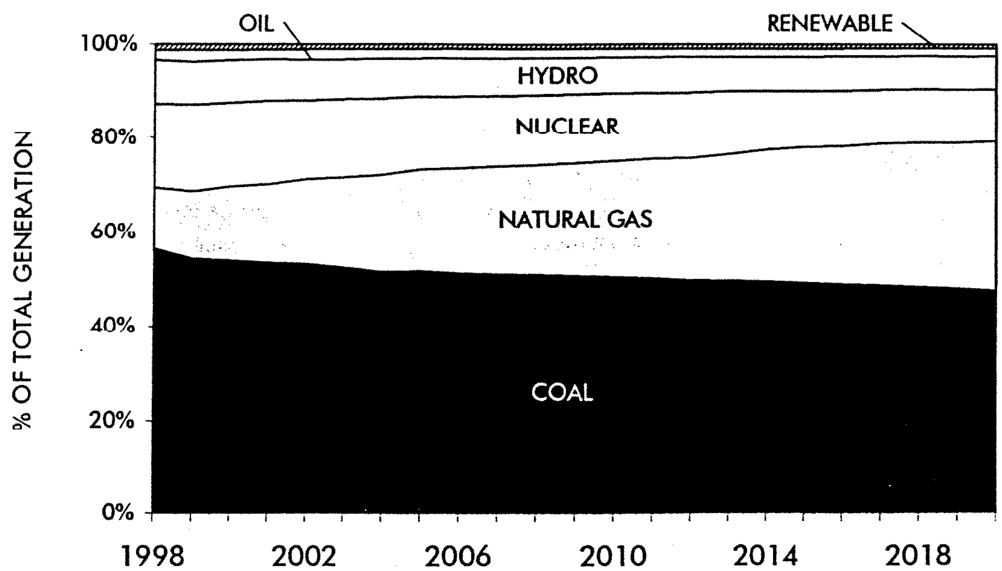
**U.S. TOTAL ELECTRIC GENERATION**
TABLE 1

| TOTAL GENERATION (MWH) | | | | | % BELOW BASE | | |
|---|---|---|---|---|---|---|---|
| | 1998 | 2005 | 2010 | 2020 | 2005 | 2010 | 2020 |
| BASE CASE | 3,423,634 | 3,870,017 | 4,140,972 | 4,573,672 | | | |
| LOW CASE | | 3,881,952 | 4,021,998 | 4,346,512 | 0% | -3% | -5% |
| MODERATE CASE | | 3,698,902 | 3,837,282 | 4,216,473 | -4% | -7% | -8% |
| HIGH CASE | | 3,651,508 | 3,529,231 | 4,041,650 | -6% | -15% | -12% |

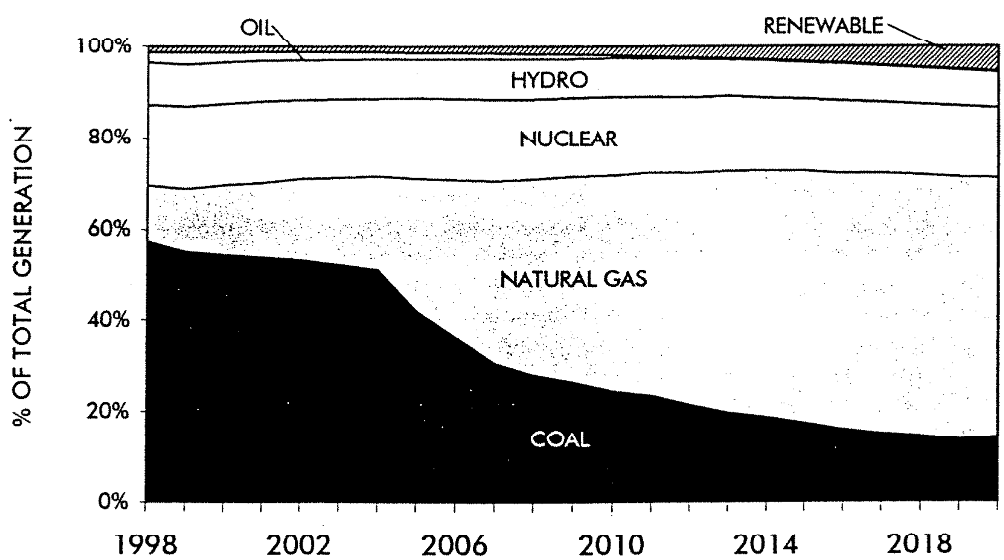
SOURCE: RDI

**U.S. GENERATION MIX BY FUEL TYPE AND BY CASE, 1998-2020**
FIGURE 3A

BASE CASE

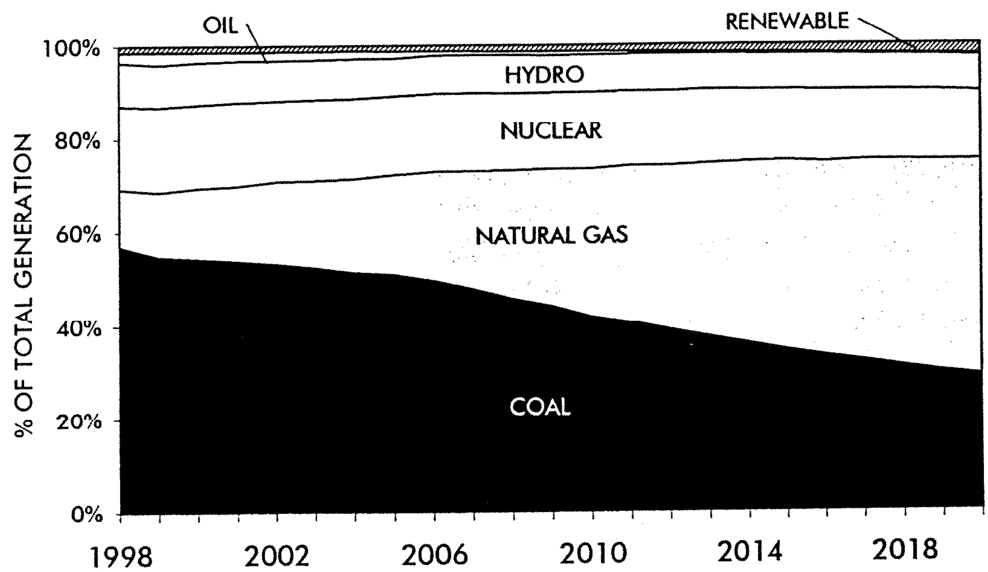



MODERATE CASE

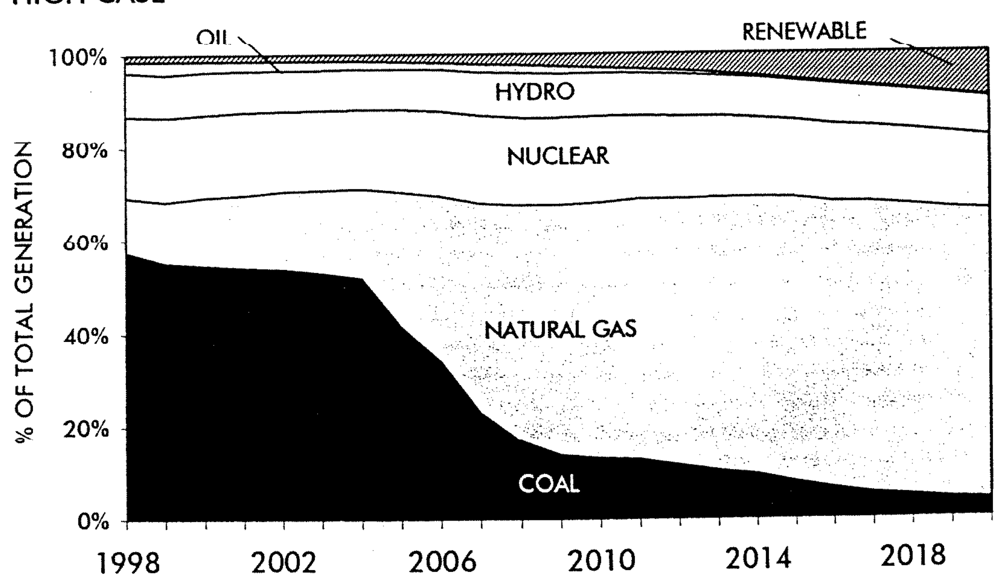


**U.S. GENERATION MIX BY FUEL TYPE AND BY CASE, 1998-2020**
FIGURE 3B

LOW CASE




HIGH CASE

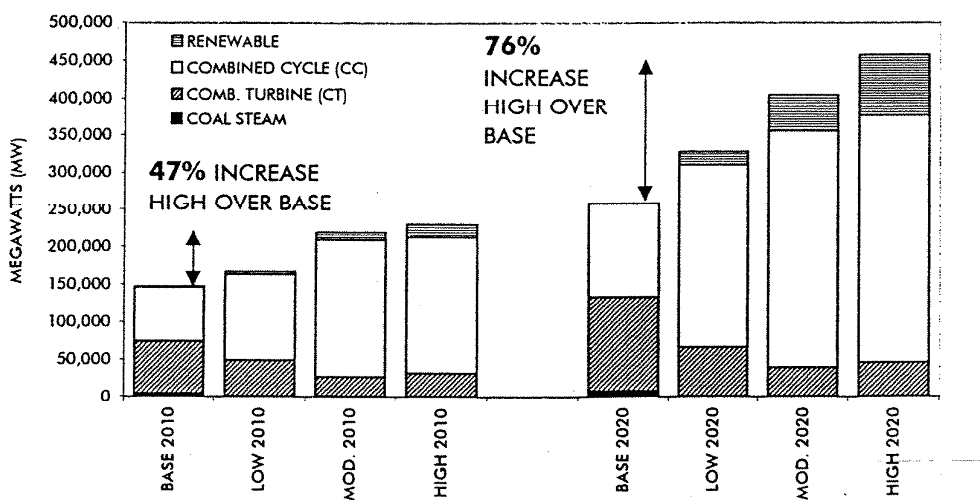


**Generating Capacity Additions** The rise in natural gas consumption for electricity generation would require the idling or retirement of coal-fired capacity and the construction of a new fleet of gas-fired power plants. Under our Base Case, RDI projects that 146,096 MW of gas-fired capacity will be built cumulatively by 2010 and 257,448 MW by 2020. In the Moderate and High Cases an additional 65,000 to 70,000 MW of gas capacity above our Base Case would be built by 2010, and 20,000 MW under the Low Case over the same period. See Figure 4.

These additions would not be evenly distributed across the country. A disproportionate amount would be built in the regions that today rely predominantly on coal-fired generation. The current installed capacity for the national coal fleet, which provides more than half of the electricity supply, is about 315,000 MW. **This capacity was built over the course of five decades, rather than a few years as is projected for gas under the carbon reduction cases.**

Although natural gas-fired generation would provide the bulk of the new additions, non-hydro renewable sources; such as wind, biomass and solar would also be increasingly called upon to provide electricity. In the Base Case about 5,000 MW of renewable capacity are expected to be built by 2020. This contrasts with over 50,000 MW and 80,000 MW of renewable capacity in the Moderate and High Cases.

**PROJECTED CUMULATIVE U.S. GENERATING CAPACITY ADDITIONS BY TECHNOLOGY**
FIGURE 4



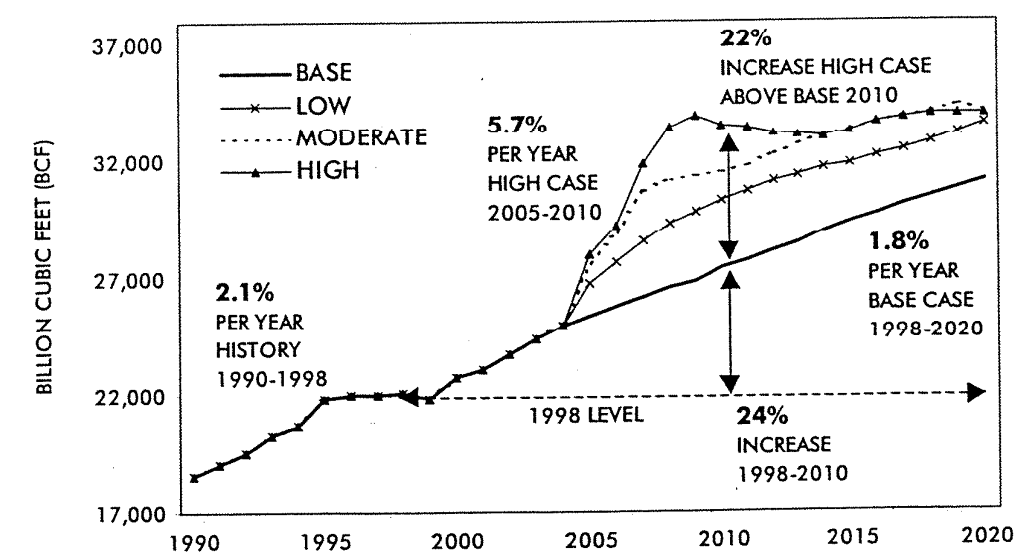

SOURCE: RDI
NOTES: COMBINED CYCLE (CC) AND COMBUSTION TURBINE (CT) ARE GAS-FIRED GENERATION TECHNOLOGIES.
RENEWABLE INCLUDES WIND, SOLAR, BIOMASS, GEOTHERMAL AND OTHER NON-HYDRO TECHNOLOGIES.

**U.S. NATURAL GAS DEMAND**

Spurred by the surge in gas-fired electricity generation, the North American gas industry would be challenged under the Kyoto Protocol to supply the market with more than 30 Tcf by 2007 under the Moderate and High Cases and by 2010 under the Low Case. The gas industry generally views 30 Tcf as a key threshold. Under Base Case conditions, RDI projects that the threshold will be crossed by 2015. See Figure 5.

Through the 1990s, U.S. natural gas demand has averaged annual growth of about 2.1% per year. RDI projects that Base Case demand in 2010 will be 24% over 1998 levels of about 22 Tcf. Average annual growth is expected to be 1.8% from 1998 through 2020. This strong growth would be spurred even higher under the Kyoto Protocol. RDI projects High Case gas demand to be 22% higher than our Base Case projection in 2010, while the Low and Moderate Cases are projected to be 10% and 15% higher, respectively. Annual growth from 2005 to 2010 would increase by more than 5.7% in the High Case, a level significantly higher than historic growth.

**U.S. NATURAL GAS DEMAND, 1990 – 2020, BASE CASE AND KYOTO CASES**
FIGURE 5




SOURCE: RDI, HISTORY EIA

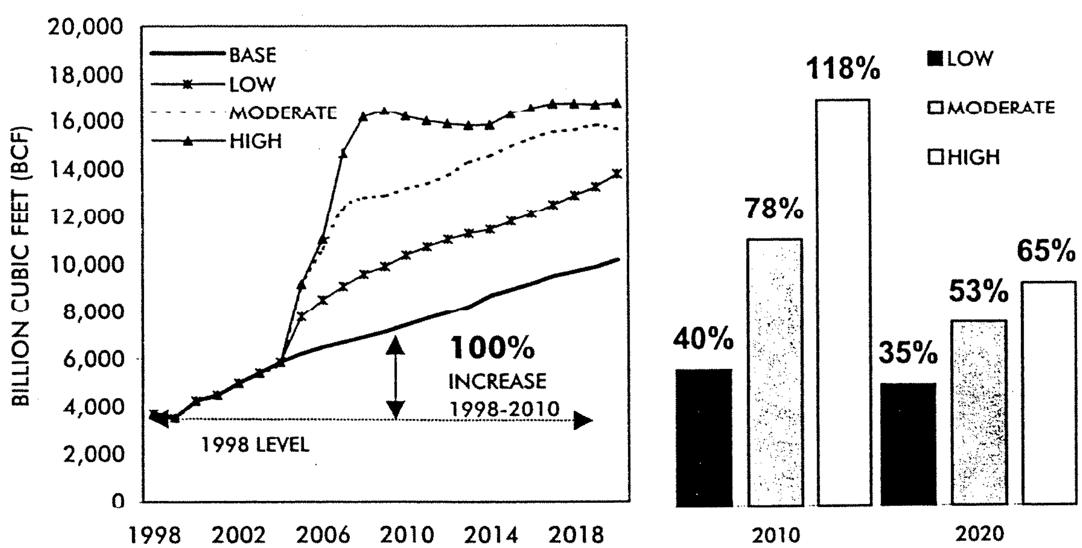
The primary driver of total gas demand growth comes from increasing use in the electric generation sector. Demand in this sector increases at close to 8% per year through 2010 in our Base Case. RDI projects electricity sector gas consumption, including grid-connected cogeneration, to grow from 3.7 Tcf in 1998 to 7.4 Tcf in 2010. This equates to a 100% increase from 1998 levels.

Gas consumption is expected to increase to substantially higher levels in the carbon reduction cases. In the High Case, gas use would more than double to about 16 Tcf of annual consumption. The Low and Moderate Cases are projected to track 40% and 78% higher than our Base Case by 2010, respectively. See Figure 6.

Under the High and Moderate Cases, electric sector demand growth tapers off through the end of the forecast period for a number of reasons. First, older less efficient gas units, primarily older steam turbine systems, are replaced with advanced combined-cycles.[6]

**U.S. ELECTRIC GENERATION GAS DEMAND, 1990 – 2020**
FIGURE 6

**% INC. U.S. ELEC. GAS DEM. ABOVE BASE**



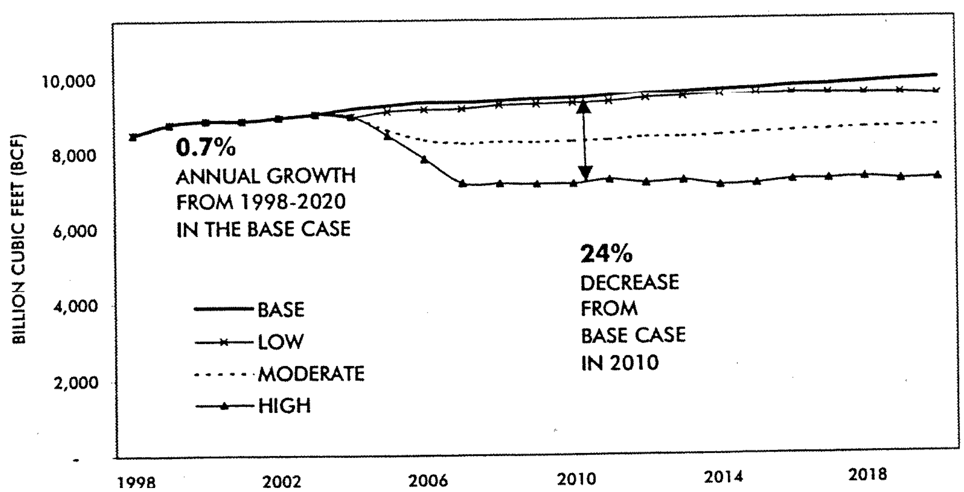

[6] New combined cycle technology, which currently has a heat-rate of 6,900 Btu/kWh, is assumed to achieve a heat-rate of 6,300 Btu/kWh by 2010.

Second, declines in economic growth, end-use efficiency gains, and increased price sensitivity are expected to create a leveling effect on electricity demand.

Residential gas demand is driven primarily by space-heating load and in the long-term by economic growth, population growth, and the average efficiency of furnaces and gas appliances. The commercial sector has significant heating load, as well as, a variety of non-heating gas applications. Natural gas is the preferred fuel source when a high degree of temperature control is required, as is necessary in many cooking and fluid heating applications. The growth in commercial demand is highly correlated with residential demand, as growth in households increases the demand for commercial services.

Residential and commercial gas demand is rapidly pushed to lower levels in the Kyoto cases because of price effects and projected efficiency gains in new gas-burning durable goods.[7] Price and efficiency effects are significant in the Moderate and High Cases, reducing demand by 1 to 2 Tcf, or 12% to 24% below our Base Case. Residential and commercial gas demand is forecast to grow at about 0.7% annually through 2020 in our Base Case.

**U.S. RESIDENTIAL- COMMERCIAL GAS DEMAND, 1990 – 2020**
FIGURE 7




SOURCE: RDI

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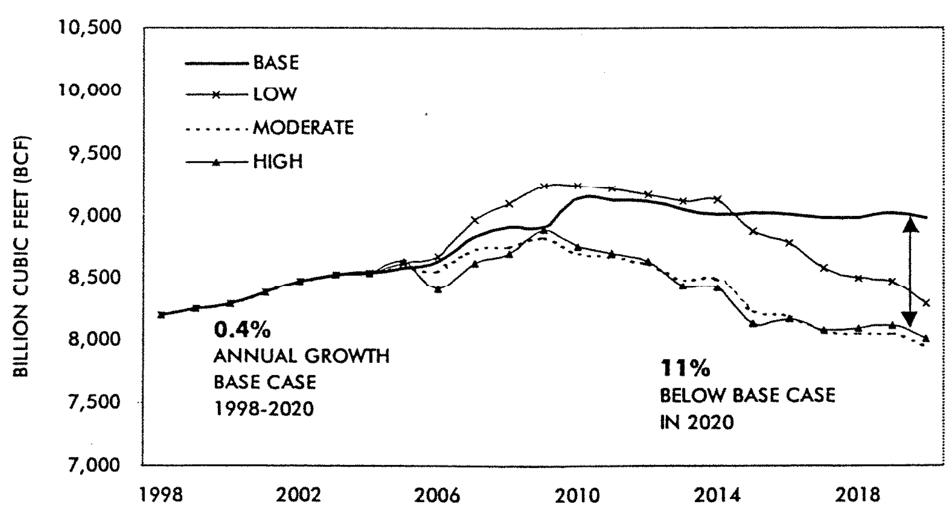
[7] Assumptions about energy efficiency gains and price elasticity of demand are adopted from the EIA work. Also, this study does not model potential effects of distributed generation on central power station construction or gas consumption behind the city-gate.

Figure 7 illustrates the steady growth projected in the residential and commercial demand sector under our Base Case and the rapid decline and leveling off that is expected in the Kyoto cases.

Industrial gas use primarily takes one of two forms, either as a feedstock for an industrial process or as energy input for space-heating, cooling, raising steam, electric generation, or other uses. The largest industrial consumer of natural gas is the chemical industry. A variety of new chemical applications and the growth in micro-chemical facilities are expected to drive growth in this sector. Metal durables, primary metals, refining, food processing, and pulp and paper mills are major contributors to natural gas demand in the industrial sector. The manufacturing of durable metal products is expected to grow in the U.S. and gas use in refining is expected to decline.

Figure 8 shows industrial gas demand within our Base Case and under the Kyoto Protocol. RDI includes grid-connected cogeneration in its definition of the electric generation sector. In our Base Case, demand increases through 2010 and then stabilizes in the vicinity of 9 Tcf per year. This result is a function of energy efficiency gains, which lower gas demand.

**U.S. INDUSTRIAL GAS DEMAND, 1990 – 2020**
FIGURE 8




SOURCE: RDI

The changing composition of the U.S. economy is also expected to limit industrial gas demand growth. The future U.S. economy is expected to have a smaller portion of energy-intensive heavy manufacturing. However, certain technologies such as gas injection for blast furnaces in steel making, and cofiring natural gas in industrial boilers should create increased gas demand. One key uncertainty is how the competition between electro-technologies and gas applications will alter industrial demand. Should electricity-based technologies permeate the market, lower growth in industrial gas demand may be offset by increases in electric sector gas demand.

Within RDI's modeling process some industrial demand growth is captured in the electric sector as most new cogeneration will be connected to the grid, potentially to earn profits selling both steam and electricity.[8] These new cogeneration projects would probably be designed to serve an industrial role first and a merchant power role second.

Under the Kyoto Protocol, RDI projects industrial gas demand will not follow a smooth, consistent trend, as several countervailing forces are at work. During the initial years of the Kyoto Protocol, industrial gas demand would increase by 1.3 Tcf to displace industrial coal. In the Low Case, fuel switching from coal to gas would actually drive gas demand to a level above our Base Case for several years. In the period after 2010, RDI forecasts a sharp decline in industrial gas demand, returning it to 1998 levels of 8 Tcf. These modeled declines result from price elasticity effects, dramatic gains in energy efficiency, and migration of industrial firms out of the country.[9] By 2020 in the Moderate and High Cases, industrial gas demand would be 11% lower than our Base Case projection.

[8] RDI's electric generation additions include an assumption of 1.4% annual growth in U.S. cogeneration gas demand. About12% of the estimated U.S. combined cycle additions that are assumed to be cogeneration systems.

[9] It is difficult to estimate that portion of the industrial base that would move to other countries. To proxy this effect, RDI removed an increasing percentage - up to 33% - of the incremental growth in chemicals sector gas demand by 2010. For example, if gas demand were expected to grow by 300 Bcf in 2010, 100 Bcf were removed. Similarly a maximum 25% of the growth in refining and primary metals gas demand was assumed to migrate. These percentages roughly align to the percent decreases in industrial output, as outlined under Industrial Composition on page 58 of the EIA Kyoto study.

# Natural Gas Supply

## INTRODUCTION AND KEY FINDINGS

**Gas supply is a critical question for Kyoto Protocol compliance.** The North American natural gas reserve base is adequate to meet even High Case demand through 2020, but achieving the necessary levels of production would be difficult. Furthermore, access to the reserve base itself requires environmental trade-offs and continued technological advancement. Key findings include:

- Gas deliverability in the Moderate and High Cases would need to grow by 5% per year for three consecutive years, 2005-2007. Average production growth in the 1990s has been less than 1% per year. Further, gas supply itself is fairly uncertain beyond a twenty-year horizon.

- Canada and the Gulf of Mexico would provide half of the incremental gas supply under the Kyoto Protocol cases. The primary sources of supply would be pushed into two supply basins, lessening diversity of supply and increasing risk of supply interruptions. These regions have similar shares of growth under each of the cases, but the risk potential is exacerbated under Kyoto, because volumes increase substantially.

- The Kyoto Protocol could force difficult environmental trade-offs. Much of the gas reserve base exists in or near environmentally sensitive offshore and wilderness areas for drilling.

- Annual well completions will need to increase by as much as 33% by 2010 to reach projected Base Case production levels. Kyoto Protocol implementation would force an additional 19% increase in well completions above Base Case levels in 2010.

- U.S. wells are depleting at an increasing rate, requiring accelerated development of new wells to maintain existing production levels. This growth of the "decline rate" will increase the burden and stress of expanding production under our Base Case and the carbon reduction cases.

**OVERVIEW**

The potential natural gas reserve base in North America has continued to grow over the last 20 years. The conventional view is that supplies will be available at a moderate cost for the next 50 to 80 years. Resource estimates indicate a strong future for natural gas production. The 1997 Potential Gas Committee places the ultimate gas recovery potential of the U.S. lower 48 states at over 800 Tcf, while the Gas Research Institute (GRI) estimates more than 1,400 Tcf. Canadian reserve estimates indicate that over 250 Tcf is extractable from conventional sources in traditional basins, and at least another 250 Tcf from coalbed methane.

While a growing gas reserve base is vital, the key issue in analyzing the potential to meet Kyoto-driven demand is not reserves, but gas deliverability and the price that will bring sufficient supply to market. Aside from a few new gas fields that are under development, notably the deep waters of the Gulf of Mexico and offshore Eastern Canada, a great deal of the gas industry activity in the 1990s has been focused on using advanced technologies on currently producing gas basins.[10] These new technologies have allowed increased production at moderate gas prices. The Kyoto Protocol would place enormous stress on the natural gas exploration and production (E&P) business, as massive increases in gas production would be required. This policy would likely force producers to seek out large gas accumulations, while simultaneously increasing drilling rates on every North American gas source. Recent finds have indicated that the offshore Gulf region holds the best hope for large gas pools, but many difficulties and uncertainties exist in tapping these sources.

Some of the best prospects for offshore drilling, like the sub-salt and deepwater regions, are complex plays requiring growth in operator knowledge and increased use of technologies that are still in their infancy. A commitment to the Kyoto Protocol would bet that these new regions could be fully developed, adding large blocks of incremental production in as little as six years.

Technology has opened the door to greater utilization of natural gas resources, and these offshore Gulf regions should be excellent production sites for many years to come. But the fact remains that many years are required to bring new fields up to high production levels. It has taken ten years, for example, for deepwater producers to reach current rates of about 800 billion cubic feet (Bcf) per year. A typical project may involve 6 to 12 months to mature from exploratory drilling to initial development.

[10] For example, 3-D seismic, horizontal drilling, and enhanced gas recovery systems.

Many gas industry participants see new technology as critical to achieving the necessary levels of growth in gas supply. Gas Research Institute (GRI) has stated that by 2015 about 30% of the U.S. gas supply depends on the availability of new technology, and that absent technological advances projected growth in gas consumption could not occur. GRI says, "Growth can only be accomplished with continued investment of a share of total industry revenues consistent with historical experience, gas supply technology improvement at levels also similar to historical experience, and significant (but not heroic) increase in drilling activity."[11]

The Interstate Natural Gas Association of America (INGAA) has also noted advancing oil and gas exploration and production technology as an important necessity. INGAA said, "Although oil and gas production often is perceived as an old-line, mature industry, its adoption of a wide range of new technologies in recent years has kept the industry at the forefront of technological innovation and dramatically reduced the effects of resource depletion. The 30 Tcf market goal is not achievable by 2010 without continued development and adoption of new technologies to improve drilling success rates, reduce factor costs and improve production efficiencies.[12]

Meeting projected gas demand growth under the Kyoto Protocol poses a greater challenge, given the restricted timetable for creating substantial increases in productive deliverability. Furthermore, the industry would have to perform at peak levels for many years into the future. The primary issues are meeting peak-year demand growth, gas reserves access, and the industry ability to drill new wells.

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[11] "Forecast highlight link between technology advances and long-term gas supply." *Gas Research Institute-GAStips*. Feb, 1998, P. 6.

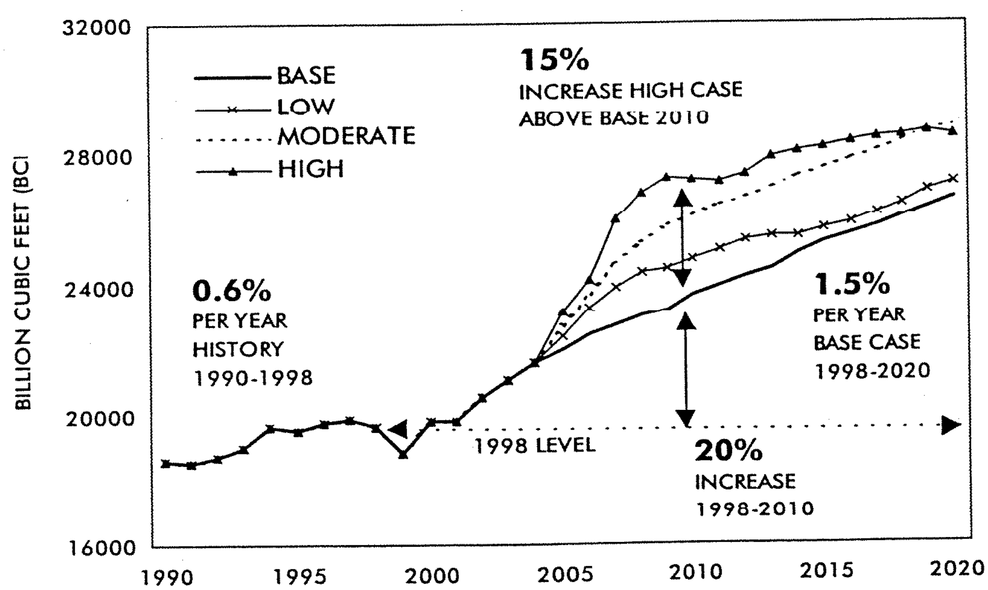
[12] "Pipeline and Storage Infrastructure Requirements for a 30 Tcf U.S. Gas Market." *The INGAA Foundation*. March 1999. P. 39.

## NATURAL GAS SUPPLY AVAILABILITY

Gas production from the mainland U.S. must grow substantially in our Base Case and Kyoto Protocol scenarios. Figure 9 shows the level of lower 48 U.S. natural gas production achieved through the 1990s and the level of production necessary to meet Base and Kyoto-driven demand. Through the 1990s, U.S. gas production has averaged about 0.7% growth per year. In the Base Case, gas production increases at an annual average rate of 1.5% per year through 2020, essentially doubling.

Doubling the annual growth rate of gas production in our Base Case over the next 20 years at moderate prices will be challenging for several reasons. The industry faces high production decline rates on existing wells, deeper drilling horizons in remote locations, and a need for continued advances in E&P technology.

**U.S. LOWER 48 NATURAL GAS PRODUCTION, 1990 - 2020**
FIGURE 9




SOURCE: RDI, EIA

An even greater challenge is represented in the accelerated production trajectories in the various carbon reduction scenarios. In the Kyoto cases, gas production would increase by about 2.0% per year through 2020. In addition, the more severe carbon reduction cases display a 1.2 to 1.5 Tcf surge in gas production in 2005. These increases are followed by successive years of growth near or well above 1 Tcf per year through 2008, after which the growth in annual gas production levelizes. The feasibility of rapidly increasing gas production in the Kyoto cases is debatable, especially given the difficulties of expanding gas production in our Base Case.

Gas production levels have remained essentially flat at about 19 Tcf annually since 1994. Even increases in drilling compelled by the strong gas prices of 1996 and 1997 did little to increase gas production. The average annual U.S. count of active rigs drilling for natural gas, a subset of the U.S. rig count (which also includes oil drilling), has climbed from around 400 per year in 1994 and 1995 to more than 500 in the last three years. This suggests that the industry has had to work harder to produce the same amount of gas. If the industry is working harder to simply maintain production, then increasing production should be viewed as that much more difficult.

**"The single most controversial issue to the industry today is gas supply."** This quote from Paul Ziff, CEO of Ziff Energy citing results from an industry survey highlights the level of supply uncertainty in the gas industry.[13] EIA has echoed these sentiments regarding Kyoto Protocol implementation by stating, **"Increasing natural gas production during the initial phases of a carbon emissions reduction program may be the biggest challenge facing the oil and gas industry."**[14]

If historic performance is any indicator of future ability, gas producers will be severely stressed to meet the gas production challenges of a carbon reduction policy. To meet forecast demand in the Moderate and High Cases during 2005 to 2007, increases will need to exceed 1 Tcf per year for three consecutive years.

Increases of that magnitude have not been accomplished since 1968-1970. Furthermore, it is uncertain that these gains could be repeated given the

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[13] "Production Drop, Demand Gains Seen Likely to Push up Prices." *Natural Gas Week.* April 29, 1999, p. 2.

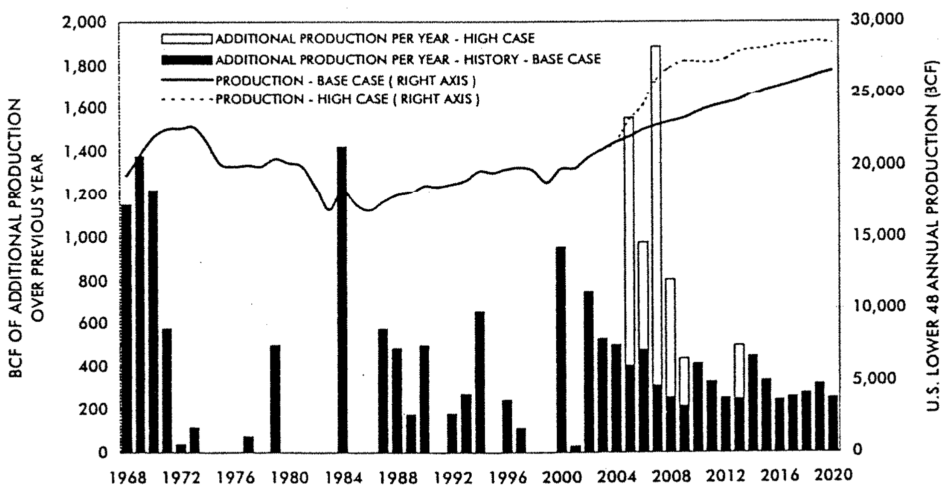
[14] *EIA Kyoto Protocol study. p. 97.*

numerous recent changes in the structure of the oil and gas industry. For example, most of the easy-to-reach reserves have been tapped; tax incentives for exploration; which existed in the 1980s, have been removed; and employment levels in the industry are much lower today.

The difficulties associated with successive production increases are displayed in Figure 10. The black bars on the graph show annual increases in production, both historically, and in our Base Case forecast. The white bars show the increases in production necessary in the High Case. The line graphs chart the annual gas production in each case. **The necessary increases in additional U.S. lower 48 gas production in the High Case substantially exceed Base Case levels and surpass the levels of historic growth ever achieved in one year.**

Increases in annual production rarely exceed 500 Bcf per year in our Base Case, while in the High Case average annual production increases during 2005-2010 are projected at 950 Bcf. This compares to average increases in production between 1968-1997 of 500 Bcf. Furthermore, the largest increase of 1,400 Bcf in 1984 was a recovery in gas demand to prior levels -- *not* an increase in productive and transmission capacity.

**THE CHALLENGE OF KYOTO TO GAS PRODUCTION IN A HISTORIC CONTEXT, 1968 - 2020**
FIGURE 10




NOTE: HISTORIC YEARS WITHOUT A BAR SHOWED PRODUCTON DECLINES.
THE PRODUCTION INCREASES THAT OCCURRED IN 1984 ARE A RESULT OF RECOVERY OF GAS DEMAND.
FORECAST INCREASES IN 2000 ARE PREDICATED ON A DRILLING RECOVERY BY THE END OF 1999.

SOURCE: RDI, EIA

**Sources of Incremental Gas Supply** Increasing gas production rapidly requires every supply source in North America to grow. Starting from current U.S. gas supply of about 23 Tcf annually, producers will need to increase gas flow by about 5.2 Tcf annually by 2010, in our Base Case. In the Moderate and High Cases, between 9.5 to 10.6 Tcf of additional supply would be required, a doubling of annual output over Base Case needs. See Table 2.

Of all the new gas production projected, about 50% is expected to be sourced from the Gulf-offshore and Canada, making these regions critical to meeting projections in any of the cases. The Texas onshore-Gulf region and the Rocky Mountain-San Juan region combine for another 25%, and the final 25% is supplied by a variety of sources primarily the Anadarko/ Hugoton and the Permian basin. In the Kyoto cases, Mexican and Liquefied Natural Gas (LNG) imports account for about 3% of the incremental supply mix. In any productive basins there are usually a variety of shallow and deep prospects. There is a trade-off between potential yield and costs of development. The overall contribution from each basin increases as gas prices allow more drilling prospects to become viable. This accounts for the relatively stable growth of gas production across the cases from each basin.

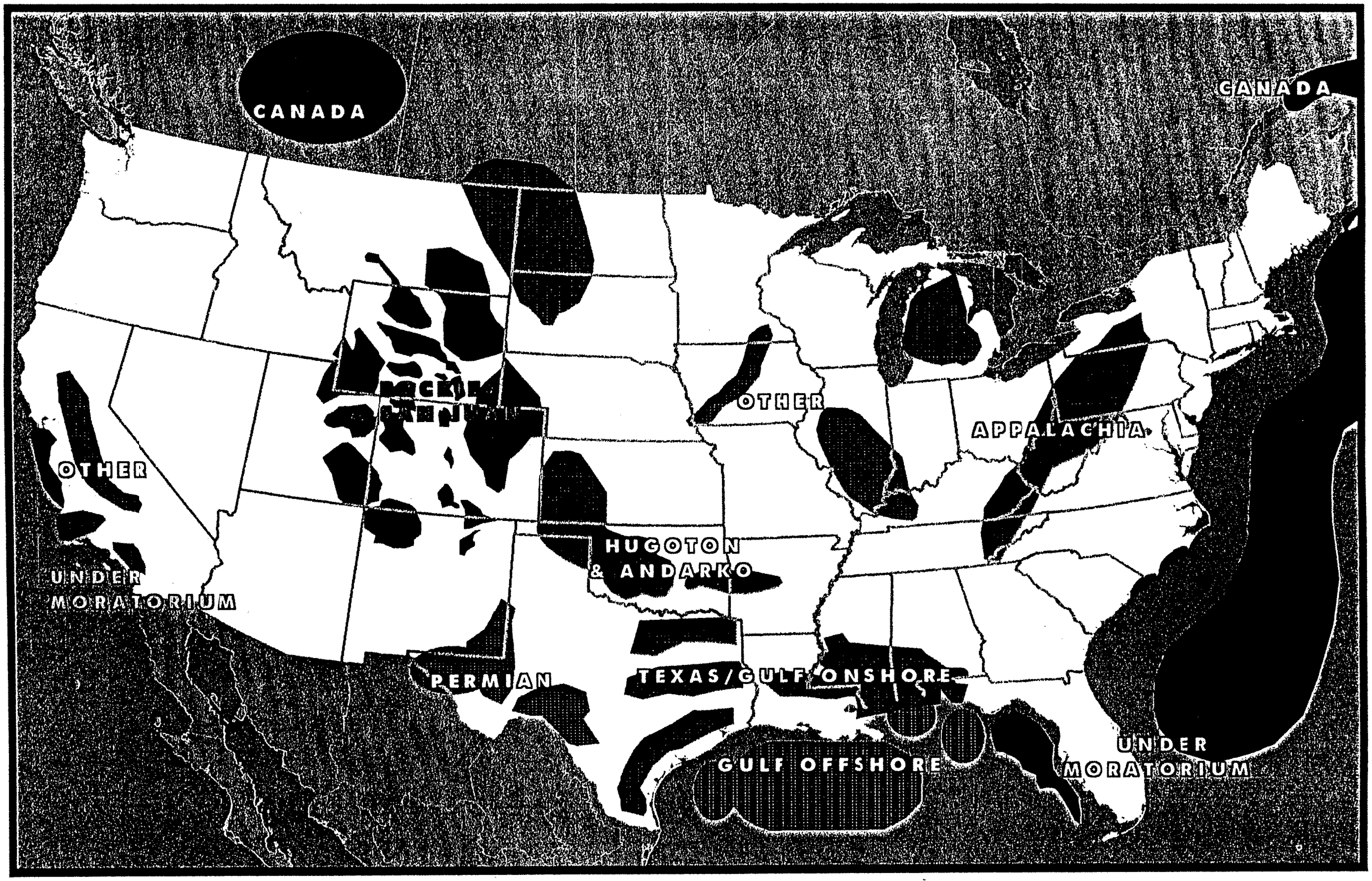
**SOURCES OF INCREMENTAL GAS SUPPLY**
TABLE 2

| **1998 U.S. GAS SUPPLY 23 TCF** | **BASE** | **LOW** | **MOD.** | **HIGH** |
|---|---|---|---|---|
| **ADDITIONAL PRODUCTION NEEDED BY 2010 (TCF)** | **5.2** | **8.5** | **9.5** | **10.6** |
| **% INCREASE ABOVE 1998 LEVELS** | **23%** | **37%** | **41%** | **46%** |
| **% FROM EACH SUPPLY SOURCE** | | | | |
| ANADARKO-HUGOTON | 7% | 8% | 8% | 9% |
| APPALACHAIN | 3% | 3% | 3% | 3% |
| GULF ONSHORE | 2% | 3% | 3% | 4% |
| GULF-OFFSHORE | 26% | 28% | 27% | 28% |
| OTHER U.S. SUPPLY | 6% | 5% | 4% | 4% |
| ROCKIES- SAN JUAN | 14% | 7% | 12% | 8% |
| TEXAS GULF | 13% | 12% | 12% | 13% |
| PERMIAN REGION | 6% | 6% | 6% | 7% |
| CANADIAN IMPORTS | 22% | 26% | 22% | 21% |
| OTHER IMPORTS | 1% | 3% | 3% | 3% |
| ALL SOURCES | 100% | 100% | 100% | 100% |

SOURCE: RDI

**MAJOR NORTH AMERICAN NATURAL GAS SUPPLY BASINS**

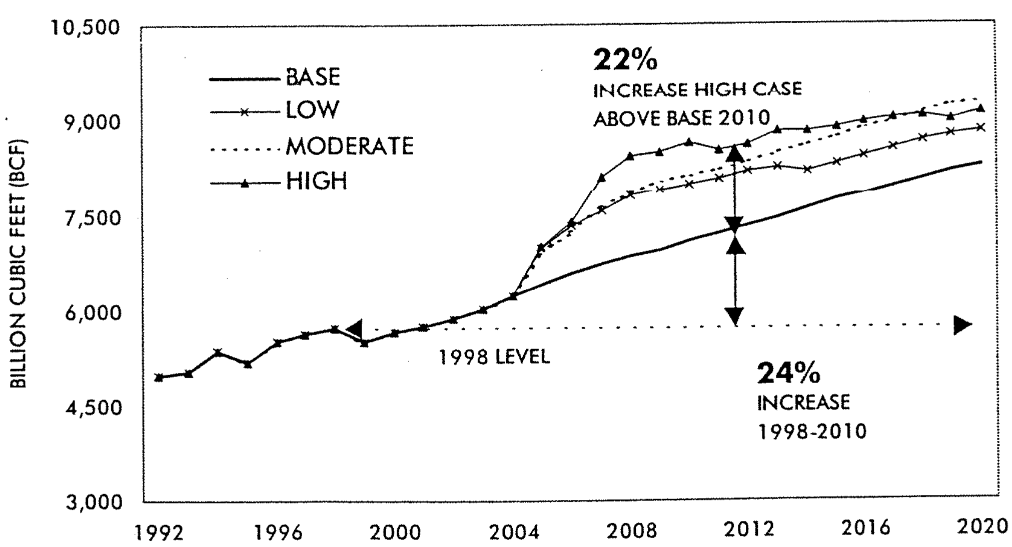
GAS SUPPLY MAP 1



Gulf-offshore: The Gulf-offshore region is projected to be one of the two primary sources of gas supply both in our Base Case and in the carbon reduction cases. The region currently accounts for 28% of U.S. gas production. Rather than being a single basin, the area has complex geology with a variety of folds, fractures and domes where hydrocarbons accumulate. Potential gas sources are sometimes called trends or plays. Areas within the Gulf-offshore region include the shallow waters, the Norphlet trend, sub-salt trend, and the deepwater.

The primary supply area in the Gulf is the shallow water, which is typically defined as waters with a depth less than 1,000 feet. This mature area currently accounts for about 85% of offshore gulf production. The other supply areas, which are discussed in detail in Volume II, tend to be deeper prospects, with unique difficulties. For example, the Norphlet trend has large wells, but they occur with high levels of corrosive by-products and hydrogen-sulfide ($H_2S$). The sub-salt trend contains sheets of salt that obscure seismic readings. Deepwater plays require specialized equipment, which lead to high capital costs. The concern related to Kyoto implementation is that these alternative supply areas in the Gulf would be taken for granted as sources of incremental production. RDI's forecast for offshore gas production increases at about 1.8% per year in our Base Case, from an initial production level of about 5.6 Tcf to a 2010 level of 7.0 Tcf, a 24% increase. In the High Case, gas production from the Gulf must reach 8.6 Tcf by 2010, a 22% increase above Base Case levels in 2010. See Figure 11.

**GULF OFFSHORE GAS PRODUCTION, 1992 - 2020**
FIGURE 11

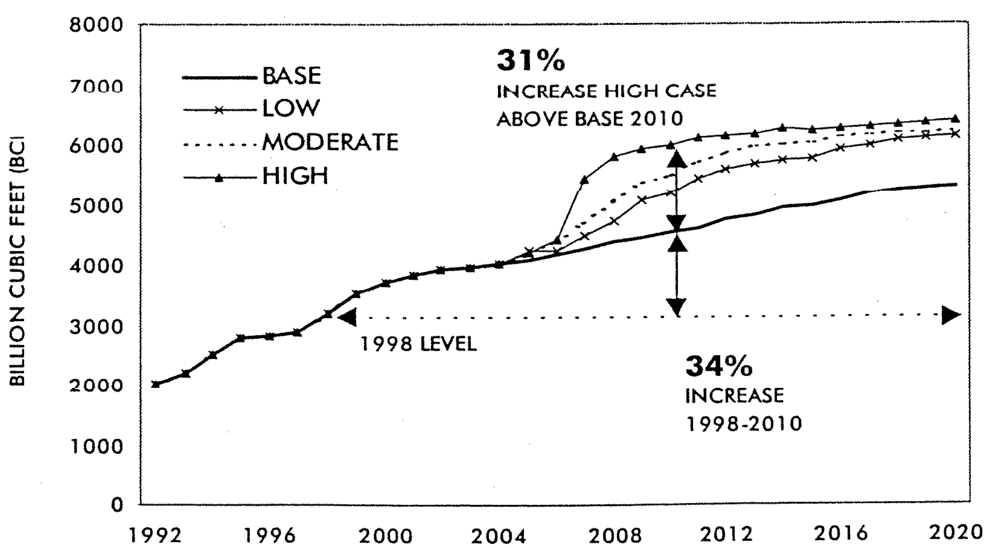



SOURCE: RDI

Canada: Reliance on Canadian natural gas would be a vital part of Kyoto Protocol compliance. To meet Kyoto-driven demand, the U.S. would need to nearly double imports of Canadian natural gas by 2010. Just as in the U.S., rapidly increasing Canadian production would be a challenge. Canadian producers would likely be willing to sell more gas to the U.S., however, Canada has the power to limit flows abroad in order to reserve supplies for its own needs or for other reasons, including environmental concerns.

Canadian production currently totals about 6 Tcf, annually, with 50% of this exported to the U.S. Canada's primary producing region is the Western Canadian Sedimentary Basin (WCSB), which stretches across the plains and foothills of Alberta and British Columbia. A recent settlement with Indian tribes in the Northwest Territories has allowed exploration and development to occur just north of the Alberta-British Columbia border, where several large gas finds have touched off a flurry of development. As these supplies are connected to the pipeline system, the Canadian gas industry will be one step closer to tapping the 55 Tcf of potential gas reserves in the Mackenzie Delta/Beaufort Sea region in far Northwest Canada. RDI assumes that connection of gas reserves in the Mackenzie Delta and other Arctic sources would not occur until after 2020 in all the scenarios. The other new source of Canadian supply is Offshore Eastern Canada, which has proved reserves of 3 Tcf and potential reserves above 60 Tcf.

**CANADIAN GAS IMPORTS**
FIGURE 12

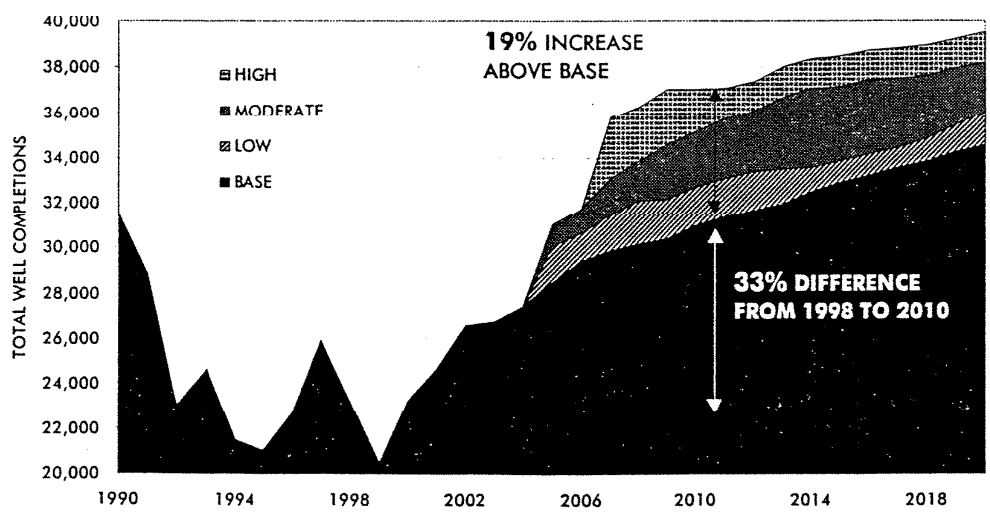



SOURCE: RDI

**Well Completions and Drilling Rigs** Reaching the levels of supply necessary under Kyoto would require large increases in the number of wells drilled each year. Well completions are projected to increase by 33% by 2010 in our Base Case and an additional 19% to meet levels projected for the High Case. In our Base Case, about half of the completions would target natural gas, rather than oil (oil wells can also produce natural gas). In the Kyoto cases on average during 2005-2010, 65% of the completions would be gas wells as oil completions decline and gas drilling increases. Figure 11 shows historic and forecast well completions for both oil and gas in the Base and Kyoto cases. Oil and gas drilling must be examined together because they share the same infrastructure and services and because Kyoto related impacts affect all aspects of the drilling business. See Figure 13.

Generating significant increases in well completions is difficult for two major reasons: equipment and staffing. RDI discussions with supply service personnel have pointed to delays in obtaining sufficient quantities of drill pipe as a potential constraint. This is especially the case for high-strength corrosive resistant piping for deep, high-pressure wells. The drilling industry has been hard hit by waves of downsizing in the oil and gas business. Many of the older workers have been forced into retirement, significantly reducing the knowledge base that can be passed on to the new generation of workers.

**TOTAL U.S. WELL COMPLETIONS, 1990 - 2020**
FIGURE 13



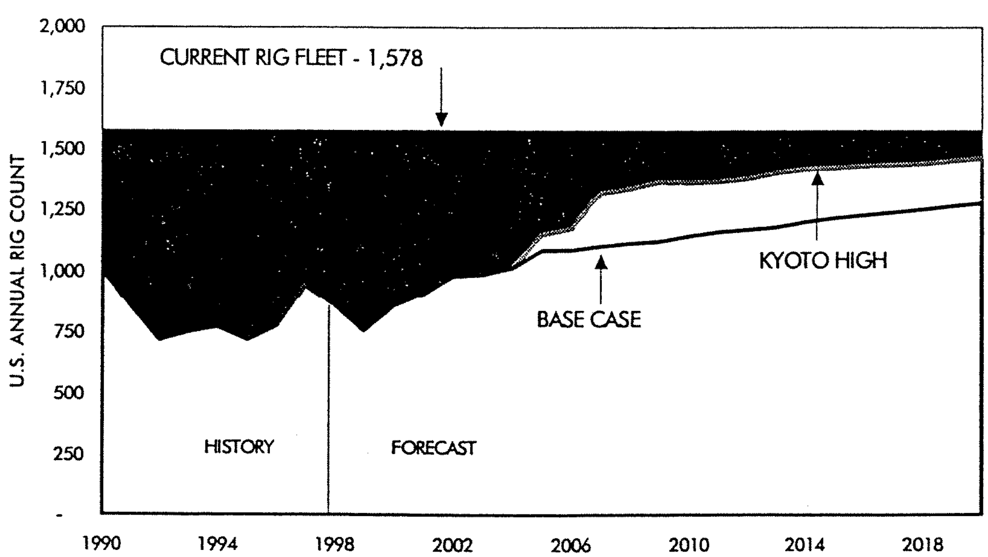

SOURCE: RDI, HISTORY EIA

Richard Mason of the Land Rig Newsletter has been reported saying that many of the employees hired in the 1996-97 drilling market upturn, were released again in 1998 -- "Employees that returned basically received a slap in the face as they were let go again." In January 1998, 1,500 drilling rigs were drilling in the U.S. this number dropped to 488 in April 1999 and has since increased to about 750. Assuming an estimate of 21 employees/rig the drilling work force has declined by about 15,000 employees since the beginning of 1998.

Mason also said, "Fortunately, because rig activity [in the second half of 1999] is ramping up slowly, there has not been an acute labor shortage. If we encounter a step level change, say 10 to 15% in the near term, we may be in trouble".[15]

The rig count describes the number of drill rigs actually drilling for gas or oil at particular time, in this case over one year. Rigs will be moved from site to site as wells are completed. The Reed rig census, a drilling industry survey, has placed the current total rig fleet at over 1,705, while the Gas Research Institute (GRI) has reported the land rig fleet at around 1,400 and the available offshore Gulf rig fleet at 178. The forecasted rig utilization rate is shown in Figure 14.

**AVERAGE U.S. RIG COUNT, 1990 - 2020**
FIGURE 14




SOURCE: RDI, HISTORY BAKER HUGHES INC.

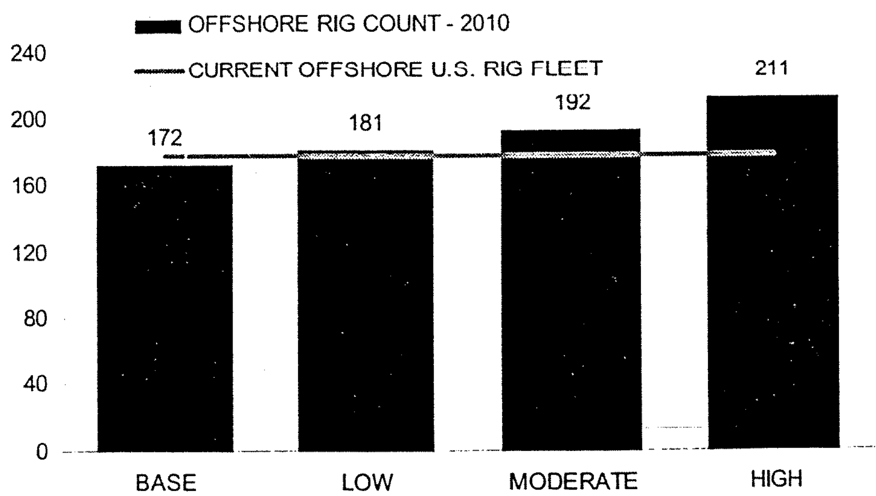
[15] "Rig activity fails to bounce back..." *Oil & Gas Journal.* Sept. 20, 1999. P.46

The rig rate moves in concert with the rate of well completions. In our Base Case, rig count estimates show activity rising from below 800 operating rigs in 1999 to over 1,000 rigs per year by 2004 and gradually increasing to over 1,200 rigs per year by 2020. Each of the Kyoto cases chart slightly higher trajectories, with High Case reaching near 1,400 operating rigs per year by 2007.

At first glance it appears that the rig fleet is sufficient to meet the challenge of the Kyoto Protocol. A more thorough examination of the rig fleet raises some concerns. Much of the rig fleet was built during the oil boom of the 1980s. Years of decay and cannibalization have led to average rig fleet reductions of about 180 per year since 1988. Furthermore, though older rigs may be available, demand under the Kyoto cases would be for heavy rigs that can drill deep land formations, or for specialized offshore drillships that can probe the deep and ultra-deep waters of the Gulf. Potential safety regulations, such as pre-contracting back-up rigs to drill emergency relief wells, could tie up more of the existing rig fleet.

Excess offshore rig capacity currently exists, but only a few of these rigs can operate in the deepwater. This means the offshore rig fleet would need to grow well before 2010. Estimates of offshore rig counts are shown in Figure 15.

**GULF OF MEXICO OFFSHORE RIG COUNTS, 2010**
FIGURE 15




SOURCE: RDI

The current offshore Gulf rig count is about 133. In the Base Case, Gulf rig counts are projected to reach about 160 by 2005 and 172 operating rigs per year in 2010. In contrast, estimates from the Moderate and High Cases indicate the need for a rig rate above 192 in 2010. The rig market may be tight as projected rig rates exceed the current offshore rig availability of 178.

Uncertainty in the rig market under Kyoto implementation revolves around being able to use the existing rig fleet and the need for additional rigs for difficult drilling environments. For the most part, new rigs will only be built if day rates for contracting drill equipment increase to levels that support the financing of rig construction. Day rates have not supported new rig construction for the last few years. The exception is offshore rigs, which serve a specialized market and have recently experienced a wave of construction. Global Marine, a offshore drilling company, has report that 44 new offshore rigs, including 14 new drillships suitable for deepwater drilling, will enter the world fleet by 2001.[16] Offshore rigs serve the global market such that rig capacity moves to the highest valued market. Kyoto implementation may encourage rig migration to the U.S. Gulf, but this depends on the conditions in global oil and gas markets under Kyoto, which is beyond the scope of this study.

The structural problems of placing labor and equipment for drilling is an issue, but it is internal to the E&P industry, which is a competitive global market. Gas price increases should stimulate industry activity and bring resources to their highest valued use. For this reason, drilling constraints are less of an issue in our Base Case. That being said, the compressed timetable for Kyoto implementation raises concerns. Without planning and capital programs set forth several years in advance of actual drilling, the ramp up to meet the surge in Kyoto demand may not be possible.

**Relationship to the Oil Markets** The E&P portion of the gas business is inextricably tied to the oil market. Gas supply development is linked to the price of gas and oil, and the current investment climate. This gives the industry a 1- 3 year focus, as projects are designed to maximize cash-flow in the current market. About 14% of onshore gas production, and 16% of offshore gas production, originate from oil wells. This gas is termed "associated" and "dissolved," as well as "casinghead" gas. The state of the oil industry at the time when the ramp up for Kyoto would be

[16] "Oil Prices, Mergers Change Drilling Markets." *Oil & Gas Journal*. Jan 25, 1999. P.33

slated to begin could create difficulties for the gas industry's ability to respond. A downturn, as in 1999, in the world oil market would decrease the level of investment in the industry, lowering oil drilling and therefore the flows of new, associated gas coming to the market. In addition, gas and oil production companies share the same services sector -- seismic crews, well control specialists, drilling contractors, etc. A poor oil market would cause these service companies to contract, leaving them poorly prepared for the Kyoto Protocol.

Drilling began to slow during 1998 as oil prices fell. As discussed above, from a gas production perspective and in the minds of investors, the natural gas industry is still linked fairly closely to the oil business. Low oil prices have caused a disincentive to exploration that has driven drilling activity to historic lows. While oil prices have recovered in recent months, the damage to exploration budgets has already been done. The downturn has hit independent producers, which is important because independents have traditionally been important in drilling exploratory wells in immature geologic formations with consequent higher risk which have often lead to new gas plays that the major producers then exploit. In the context of being in position to meet Kyoto-driven demand in a few years, the industry is moving in the opposite direction — laying off workers and decreasing drilling budgets.

**The Difficulties of Increased Production Decline** Well production naturally decreases as hydrocarbons are extracted, as represented by the decline rate. The average decline rate for U.S. wells was 14% per year in 1990 but 23% for 1997. Offshore wells decline faster than land wells as a result of water pressure on the formations. This phenomenon is especially severe in the shallow water regions of the Gulf. Offshore decline has climbed from around 21% in 1990 to almost 40% in 1997. Analysts project decline rates for offshore gas to reach 50% or even 60% by the middle of next decade.

Two factors have led to an increase in the average decline rate of wells. First, combinations of flow enhancing technologies have been developed to increase production rates. Second, 3D seismic and horizontal drilling have made smaller fields within the primary production regions economic to drill. These smaller fields naturally drain quickly, contributing to the overall basin decline rate. The bottom line is that if decline rates increase, the industry must drill more wells just to keep the same levels of production. In a Kyoto Protocol world, producers would fight steep decline rates while attempting to increase deliverability. Analysis presented in Volume II of this study indicates that well completions may need to increase by an additional 20% in the Moderate Case if decline rates are higher than expected.

The costs of additional completions could raise the price of gas supply above forecast levels.

The E&P industry is leaner and more efficient than at any time in its history, but it is highly unlikely given the current state of the industry that large, consecutive annual increases in gas production are possible. When all of the factors are taken into account, gas supply capability under Kyoto Protocol implementation is a critical question.

**Gas Reserve Access and Environmental Concerns** Access to gas reserves is an issue in the Gulf-offshore, Canada, and the Rocky Mountains regions that adds a final uncertainty to the prospect of increasing production from North American sources. The desire to increase gas production at a low cost for air quality reasons directly conflicts with policies to limit drilling in environmentally sensitive regions. Executive order prevents any drilling on federal offshore waters in most U.S. coastal regions outside of the Texas/Louisiana coast. Currently, an exemption to this order exists for existing drilling leases. This exemption has recently become an issue in presidential politics, as Al Gore would like to revoke this exemption and prevent all drilling in those offshore regions.[17] The foremost of these restricted regions is in the Gulf of Mexico west of Florida. The region is considered to have excellent resource potential, as supported by several large finds that include the Destin Dome. Other restricted areas include Atlantic coastal waters and most of the California Coast. In California, legislators have sought termination on a number of offshore drilling leases in the desire to expand marine sanctuaries.[18]

Environmental concerns are not limited to offshore. Onshore regions of the Rocky Mountains also have significant tracts of public land that are potential flashpoints for policy conflict. Environmentalists have already opposed the leasing of tracts for exploration. Recently, Earthjustice, the Wilderness Society, and the Sierra Club intervened on an appeal to the Forest Service by the oil and gas industry to offer leases in Lewis and Clark National Forest.

Another environmental issue that has emerged in the West is water management associated with increased oil and gas drilling. Coalbed methane producers pump thousands of gallons of water out of formations before gas starts flowing. In some cases, water produced from oil and gas drilling is intelligently routed for irrigation

[17] "Gore to ban drilling off key states if elected U.S. president" *Oil & Gas Journal*. Nov. 1, 1999. P.37

[18] "Drilling off California hits new roadblocks" *Oil & Gas Journal*. Nov. 1, 1999. P.36

or ranching, but more often it is allowed to run-off into the arroyos and drainages, and wasted. The produced water may also contain undesirable heavy elements or toxins. The high levels of gas production required in the Kyoto cases create concern about a lowering of aquifer levels for water wells and other purposes. In addition, the extra water often supports weed growth, which can result in the encroachment of noxious weeds into agricultural areas, and natural grasslands. In the Canadian Northwest, stringent environmental restrictions on production activity are enforced in parts of Alberta and British Columbia. [19] Furthermore, eco-terrorism in Western Canada has raised concerns over well and pipeline sabotage and wider public opposition.[20]

Producers have voiced concerns about reaching a 30 Tcf market without broader access to these public lands. One reason is that purchasing land from a small pool of private holdings drives up development costs. From an environmentalist perspective, the aesthetic and recreational value of leaving these areas untouched by the drill bit outweighs the resource value of these lands.

RDI assumes a high likelihood that drilling would be permitted in the Eastern Gulf and in other sensitive region under the Moderate and High Cases, but this assumption is at odds with current policy. The ultimate resolution of these environmental trade-offs is unclear.

[19] Heavy equipment is restricted in tundra regions during springtime because the terrain is muddy and fragile as the ground thaws.
[20] Over 160 acts of well vandalism occurred in Alberta in 1998. This resulted in over $1.5 Million in damages. Natural Gas Week, January 19,1999. P.1.

# Natural Gas Transmission

## INTRODUCTION AND KEY FINDINGS

Kyoto Protocol implementation would present a unique shock to gas markets. There is no historical parallel to the scale and focus of expansion that would need to be undertaken on the North American pipeline system in such a short time frame. The combination of construction requirements, regulatory and environmental delays, and market dynamics would make adding pipeline capacity under the Kyoto Protocol a daunting challenge. Key findings include:

- More than 24,000 miles of additional pipeline would need to be laid in the U.S. in the High Case between 2005-2010 compared to 12,000 miles in the Base Case. Only 15,000 miles of pipeline were constructed between 1990-1998.

- Peak-year requirements for additional capacity of more than 7,000 miles of pipe per year would force construction levels to three times the current industry average of 2,000 miles per year.

- Landowner opposition, regulatory hurdles, and contractual issues have slowed pipeline construction in recent years. Such delays could not be tolerated in the tight timeframe for Kyoto Protocol implementation and would jeopardize U.S. compliance and gas deliverability.

- As the largest and fastest growing gas consuming sector, electric generators would likely be forced to finance pipeline expansions under the Kyoto Protocol, either via commitment to firm contracts or even direct investment. Reluctance to commit to firm contracts could delay timely pipeline construction.

- The electric sector shift to using gas for baseload generation under the Kyoto cases would limit the seasonal transportation flexibility afforded by gas storage, because year-round pipeline utilization is higher. The loss of this flexibility would amplify pressures for pipeline expansions.

**OVERVIEW**

Kyoto Protocol implementation would reshape the gas market to such a degree that it is difficult to understand what the true pipeline requirements may be. However, by developing estimates of gas demand by sub-state region and carefully identifying pipeline-customer connections, RDI determined the potential impacts on individual sections of the pipeline grid. This modeling provides an indication of overall gas transportation capacity needs in various regions of the country.

In the Base Case, increasing gas flows from supply regions, in conjunction with rising electric sector gas demand, result in pipeline constraints. As the costs of carbon are recognized under the Kyoto Protocol, coal-fired generation would likely shut down or otherwise curtail generation. This would cause gas generation to serve more of the electric baseload. **The increase in gas demand for baseload electric generation would occur simultaneously with seasonal space-heating gas demand and lead to pipeline constraints.**

In general, four types of gas infrastructure expansions would be required in both the Base Case and the Kyoto cases.

- Lateral - Additional lateral pipeline would be needed to bring gas from the interstate mainlines to power plants. This may mean expansion of an existing lateral line or an entirely new pipeline to the generation site.

- Consumption Area - Interstate capacity expansions would be necessary in the gas consumption regions to serve the new laterals. These expansions are primarily driven by changes in electric generation demand for natural gas.

- Production Area - Capacity would be necessary to allow increased production to flow from gas supply regions. Access to new supplies, primarily Canadian, provides flexibility to gas customers in our Base Case, but is essential to meet gas demand in the Kyoto cases.

- Storage - New gas storage facilities would be required to balance pipeline pressures, and provide peaking services, and store production increases in off-peak periods.

Pipeline expansions are a region specific engineering task. The size and costs of expansions are determined by a series of factors. Pipeline companies encounter constraints on parts of their systems, an "open season" is conducted to determine shipper interest in a new pipeline; and a project is configured based the appropriate pipe sizes, pressure, and system needs. After an expansion receives regulatory approval, an environmental review will need to occur before the project can begin construction.

The most time-consuming portions of pipeline construction are trenching and welding of pipeline segments. Difficult terrain can substantially add to the cost of a pipeline. A single river crossing can cost as much as many miles of open ground pipe laying. Some advances have been made using robotic welding techniques, but the final welds on a pipeline must generally be done manually. After the pipe is welded and placed in the ground, a rigorous pressure testing process must be completed before it can go into service. The key constraint on pipe building is availability of high-grade steel that can handle pressures in excess of 1,200 pounds/square inch at atmospheric pressure (psia). Some of the latest pipeline projects are attempting to operate above 1,700 psia. The older existing U.S. interstate pipelines typically operate between 800-1,000 psia.

The time required to bring a project from proposal to service varies with the size of the project. For example, the new Discovery pipeline from the offshore Gulf region and its associated gas processing plants in Louisiana took a little under one year to build. On the other hand, the massive Alliance Pipeline Project from Canada to Chicago has been on the table for two years and is now under construction for a late 2000 start up. Major pipeline expansions commonly take one to three years to bring into service.

The 1990s have seen a good deal of pipeline construction, with major "greenfield" pipeline projects such as Kern River and Mohave into California, Iroquois pipeline in the Northeast, and new offshore Gulf pipelines. In addition, a number of large system expansions, such as PG&E Northwest and Northern Border moving gas from Canada into the U.S., were placed into service.

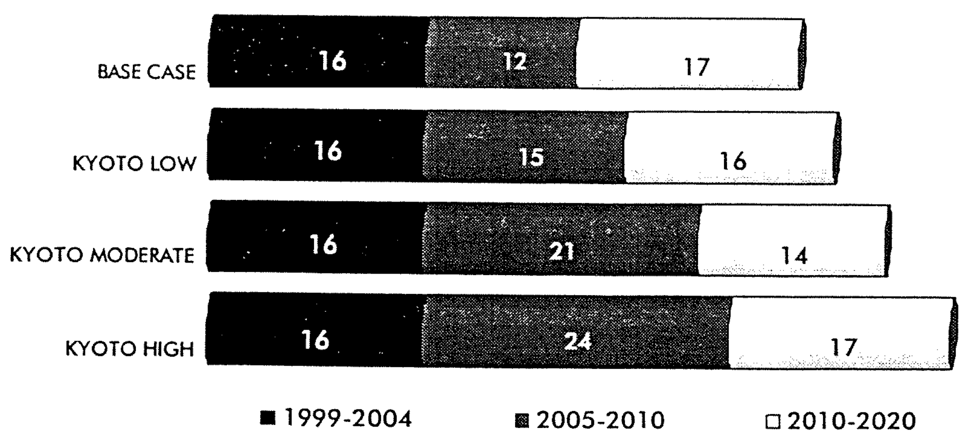
Major expansions will occur over the next several years to increase pipeline capacity from Canada and the Gulf of Mexico. The major new pipelines include the Alliance pipeline from British Columbia to Chicago and the Maritimes and Northeast Pipeline from Nova Scotia. In addition, several competing pipelines are proposed to bring supplies from the Midwest to the Northeast. Furthermore, gulf pipelines are expanding in places like Mobile Bay, Alabama to access offshore production, and several projects are proposed to serve growing natural gas markets in the Southeast U.S.

## ESTIMATED GAS PIPELINE EXPANSIONS

Several general trends in the pipeline industry have emerged that drive the expansion activity in our Base Case projection. First, 1999-2000 is expected to be a peak construction period that will give end-users unprecedented access to Canadian supplies. Second, the construction activity in the next several decades will primarily be expansion and replacement of pipeline along existing routes. Fewer new projects are anticipated through virgin corridors because of environmental concerns. Finally, activities will likely center around upgrading facilities to meet the needs of electric generators.

Projections of new pipeline construction including replacements are shown in Figure 16.[21] Our Base Case has 16,000 miles of pipeline in the period between 1999-2004. This compares with about 15,000 miles built between 1990 and 1998. The period between 2005 and 2010 is expected to see 12,000 miles of expansion. RDI projects that sharp increases in natural gas pipeline construction would occur during 2005–2010 under the Kyoto cases. Over 21,000 miles of new pipeline would be required between 2005-2010 in the Moderate and High Cases.

**U.S. CUMULATIVE PIPELINE MILEAGE BY TIME PERIOD AND CASE**
FIGURE 16. THOUSANDS OF MILES OF PIPELINE




SOURCE: RDI

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[21] Segments of pipeline periodically need to be replaced, due to corrosion, leakage and accidental damage. INGAA Foundation has reported that replacements have averaged about 0.5% of operated mileage per year. This equates to 1,300 miles of replacements per year assuming total U.S. transmission pipeline mileage of 260,000 miles.

Expansions of this magnitude would amount to a doubling of construction activity over Base Case levels. Furthermore, much of the pipeline capacity would need to be available in the 2005-2008 time period. This means construction would have to begin several years before capacity was required. Furthermore, some of these pipeline expansions could only be planned after a detailed understanding of where new power plants would be located, resulting in a shorter planning horizon.

**Peak-Year Requirements** RDI's projections for pipeline capacity expansion show that significant pipeline capacity would be required to meet carbon reduction targets. Over 40,000 miles of pipeline expansion would be required in the High Case between 1998 and 2010, up from a 28,000 miles required in our Base Case over the same time period. Furthermore, the initial years of Kyoto implementation should force pipeline construction to levels significantly above historic efforts.

Of the concerns voiced about meeting the pipe capacity requirements of our Base Case, most forecasts do not cite actual physical ability to build pipeline as an issue. The Interstate Natural Gas Association of America (INGAA) projects about 25,000 miles of pipeline expansion between 1999–2010. Further, INGAA says that its forecast of 2,000 to 2,100 miles of pipe per year is within the levels of pipeline construction historically achieved.[22] INGAA stated, however, that the industry will be a challenged to meet those levels if pipelines are not able to earn a higher return on pipeline investments than currently allowed.

INGAA also has also noted that there needs to be a balance between environmental concerns and the energy needs of the growing U.S. economy – a tension point under the Kyoto Protocol. RDI's Base Case forecast of 28,000 miles by 2010 is slightly higher than INGAA's as a result of fairly aggressive assumptions about currently proposed pipeline projects. Volume II of this report provides additional detail on all aspects of RDI's pipeline projections.

The stress on the pipeline industry is illustrated in Figure 17. The black bars show the annual miles of pipeline construction both historically and in the Base Case projection.[23] The white bars show the additional pipeline mileage that is necessary

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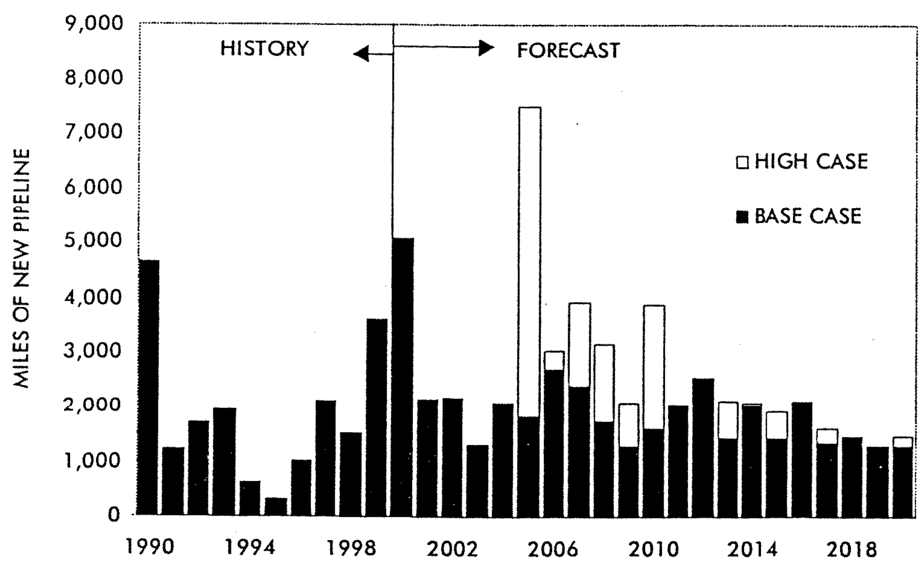
[22] "Pipeline and Storage Infrastructure Requirements for a 30 Tcf U.S. Gas Market." *The INGAA Foundation*. March 1999. P. 37-38.

[23] The historic construction data shown are from Oil and Gas Journal's *Pipeline Economics Issues.* The Oil and Gas journal uses a methodology that counts any pipeline that is under construction, initiating construction, or has a high potential of beginning construction that

in the Kyoto Case. The more than 7,000 miles of pipeline necessary in 2005 surpasses the levels of construction achieved in the last 10 years. In addition, the levels of construction forecasts for the period between 2005 to 2010 are significantly higher than the 2,000 miles per year that INGAA characterized as a challenge.

**The set of expansions required under the Moderate and High Cases is a challenge without historic precedent.** The pipeline industry's ability to place sufficient pipeline capacity in service will be stressed. This stress would come partially from physical construction constraints, but also delays from contracting, financing, siting, and regulatory issues.

**MILES OF PIPELINE CONSTRUCTION PER YEAR – BASE CASE AND KYOTO HIGH**
FIGURE 17




SOURCE: RDI

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year. This can lead to double counting when a project takes several years to complete. The historic data presented here are adjusted for double counting.

**Logistics** The bulk of the gas pipeline required for Kyoto Protocol compliance would need to be laid during 2005–2010 and would be characterized by pipeline constraints. RDI's modeling points to 2005 as being the peak year for construction. As the cost of carbon is recognized, gas becomes the most economic option for generation and demand surges. The fact that the Kyoto compliance period begins in 2008 is less important.

Existing pipeline capacity through the Canadian and offshore Gulf corridors would become stressed in 2005 as the build-up begins. **Difficulties for energy market could be possible in the event that pipeline projects cannot be placed into service in time as a result of shortages of high-grade steel, skilled welders, or capital or other critical components.**

To make a rapid sequence of natural gas capacity expansions occur, the electric and gas industries would need to work together very closely. Power producers essentially would be forced to plan simultaneously all of the gas generation projects in a region, then rapidly determine the lateral expansion paths and mainline sources of gas. Next, a capacity assessment would be needed to determine how much capacity might be released from existing shippers and how much pipeline expansion is necessary. Electric generators would then probably be required to sign long-term contracts for capacity, prior to submitting the expansion before FERC.

At that time opposition to the project would be voiced and alternative plans would be entertained. Right of way and landowner issues would be dealt with, along with other environmental concerns. FERC would then review the necessity of the project and issue a certificate. Project developers can finally begin construction, clearing land, trenching, and laying pipeline. After passing all construction inspections and rigorous hydrostatic testing, the system will be ready for service. This entire process would have to be repeated for a multitude of major expansions across the U.S. and Canada over a period of several years.

**Electric Sector Contracting for Pipeline Capacity** A disconnect exists between the short-term nature of the gas market and the long-term contracts necessary to finance pipeline construction. To expand the pipeline grid at a rapid pace in the Kyoto cases, electricity generators would likely need to make long-term commitments to pipeline capacity. In the past, generators have been reluctant to make those sorts of commitments, and they will continue to be discouraged to do so under deregulation.

Natural gas generators seek arbitrage opportunities between the price of gas and the price of power. The cost of gas transportation is a factor in the dispatch price of the generating unit. Currently, gas-fired generators often look to the interruptible or capacity release markets for discounted capacity during the slack periods of pipeline utilization, which correspond with the summer peaks of the electric market. These practices will likely change under the Kyoto Protocol, as gas units will become baseload.

In 1998, local distribution companies (LDCs) held 56% of the long-term firm pipeline contracts, while electric utilities held less than 5%. As LDCs face the prospect of state-level unbundling, they realize that today's long-term contracts may be tomorrow's stranded costs. Thus the LDCs may be increasingly reluctant to continue these sorts of commitments.

If LDCs are looking for shorter contract terms because of regulatory uncertainty, and if pipelines are encouraged to be risk averse because of the provisions of FERC policy, the question becomes: who will bear the risk associated with the vast expansion of infrastructure needed to meet projected gas demand under Kyoto? The burden would most likely fall on three industry sectors -- producers, marketers or the electric generators.

Pipeline projects in recent years have tended to be projects with clearly identifiable beneficiaries, most often bottlenecked producers. Producers have been prominent among the sponsoring shippers for the construction of Kern River out of the Rocky Mountains, the PG&E Gas Transmission NW expansion, the Alliance project, and the Maritimes and Northeast. These producers clearly benefit from market access for their supplies.

Natural gas marketers would be other potential pipeline investment contributors. These entities have recently begun take a larger role in supporting pipeline projects, such as the Independence Pipeline Project and others. Unregulated affiliates of larger energy service companies or independent marketers might also be expected to provide investment for some of the natural gas pipeline expansions that would be driven by higher demand under implementation of the Kyoto Protocol.

**Given that natural gas producers and marketers will play a role in pipeline construction, electric generators will likely bear a majority of the investment costs of pipeline expansion, given that they will require a majority of the new capacity.** Costs would include both direct costs of building pipeline to natural gas-fired power plants, and a portion of the interstate gas pipeline expansions, through the firm supply contracts that they would likely hold. Without electric generator sponsorship, rapid increases in natural gas pipeline capacity would become unlikely.

Electric sector contracting for pipeline capacity is a tension point between the merchant power plant developers that our trying to secure the lowest gas transmission prices possible to better justify the economics of their projects, and the pipelines which need the revenue assurances that firm contracts provide. It is unclear how these tensions would resolve themselves under the Kyoto Protocol.

## THE ROLE OF GAS STORAGE

Storage facilities are a vital part of the reliable delivery of natural gas to end-users. Under Kyoto, the need for storage to serve power production would intensify. In some cases, market area storage may be a substitute for pipeline capacity, and therefore an alternative to new pipeline capacity. Gas storage can best substitute for pipeline capacity when there is high variation in gas demand or price. Variation in demand allows suppliers to move gas into storage during slack periods, then in peak periods both storage and interregional pipeline capacity can be used to serve gas customers.

Variation in price can allow a shipper to buy natural gas when it is relatively inexpensive, store the gas, and sell back to the market when prices are high. Gas storage would be a key issue under Kyoto Protocol compliance, in terms of changes in its use and requirements for additional capacity. U.S. natural gas storage capacity is currently about 3.7 Tcf, or 16% of annual consumption, and withdrawal capacity is 75 billion cubic feet per day (Bcfd). Approximately half of this storage availability is in consumption regions; the rest is located near gas production.

The value of storage is tied to the flexibility it provides in meeting changes in natural gas demand. Within the market environment of our Base Case, natural gas storage supports pipeline capacity by providing LDCs with the flexibility needed to meet winter heating demand. That is, storage lessens the LDCs exposure to pipeline transportation constraints during the high demand winter months. Conversely, electric generators face peak conditions during the summer when pipeline capacity is slack, at which time inexpensive interruptible pipeline transportation is often available. Electric generators may sometimes, but not always, be able to avoid firm pipeline contracts by a combination of interruptible transportation and natural gas storage. Further, there is potential for coincident gas and electric load in Florida and the Northwest.

The gas market under the Kyoto Protocol would be much different. In general, gas-fired electric generation units would serve more of the year-round electricity baseload demand. This means that firm pipeline transportation contracts would be required, which would diminish the usefulness of storage and create pressure for pipeline capacity expansions.

In our Base Case and all of the Kyoto cases, gas storage will be important to electric generators for daily load balancing and meeting peak-day requirements. In addition, storage will serve as a short-term emergency source of supply in case of pipeline outages. These functions are best served by high-deliverability salt cavern storage. But high deliverability storage can only be developed in certain locations and is subject to many of the same environmental concerns and regulation as pipelines, including certification and opposition from nearby landowners. In addition, salt caverns have salt and brine disposal issues that are unique to storage operations.

Existing storage would be used differently under the Kyoto Protocol to serve some of the electric sector needs. Additional high-deliverability storage capacity should be required to support peaking and balancing needs because of the variability of electric load and generation dispatch, but this type of storage capacity is not a substitute for pipeline capacity.

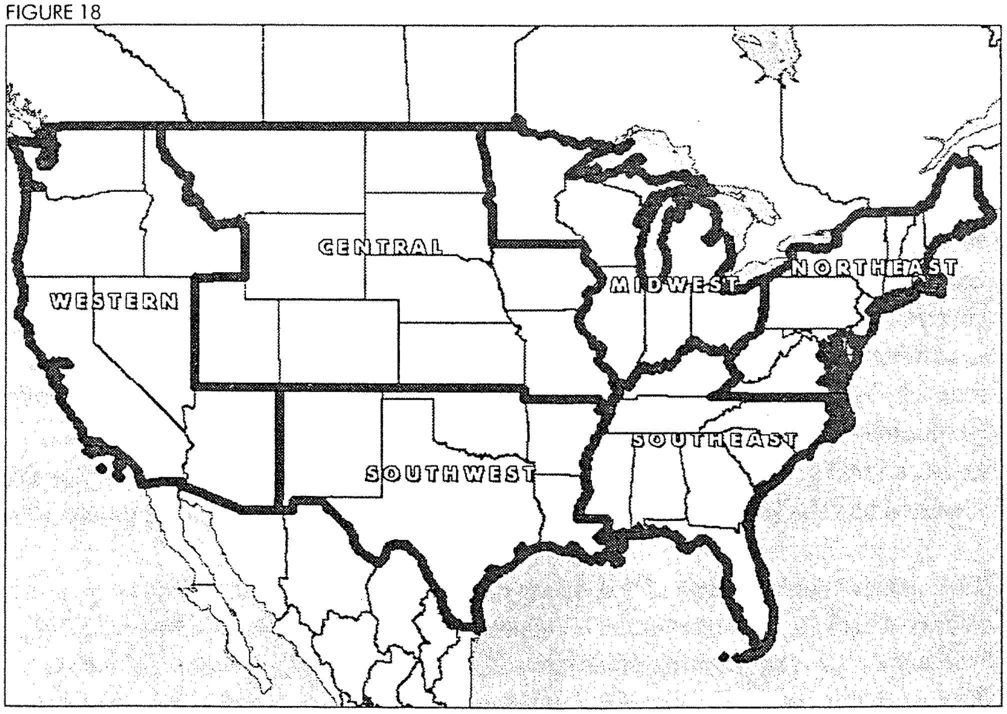
**GAS TRANSPORTATION REGION PROFILES**

Without timely expansion of the interstate pipeline grid, implementation of the Kyoto Protocol would lead to capacity constraints. Therefore, Kyoto-driven expansions need to be placed in the context of the existing pipeline grid and current interregional gas flow. The following regional profiles of pipeline capacity detail the stresses associated with the 2005–2010 build-out of natural gas pipeline capacity.

Two maps detailing gas pipeline capacity, demand, production, and storage are presented for each region – one map depicting current infrastructure and flows and the other projecting the situation under the Moderate Case in 2010. See appendix for full color maps of pipeline infrastructure in each region.

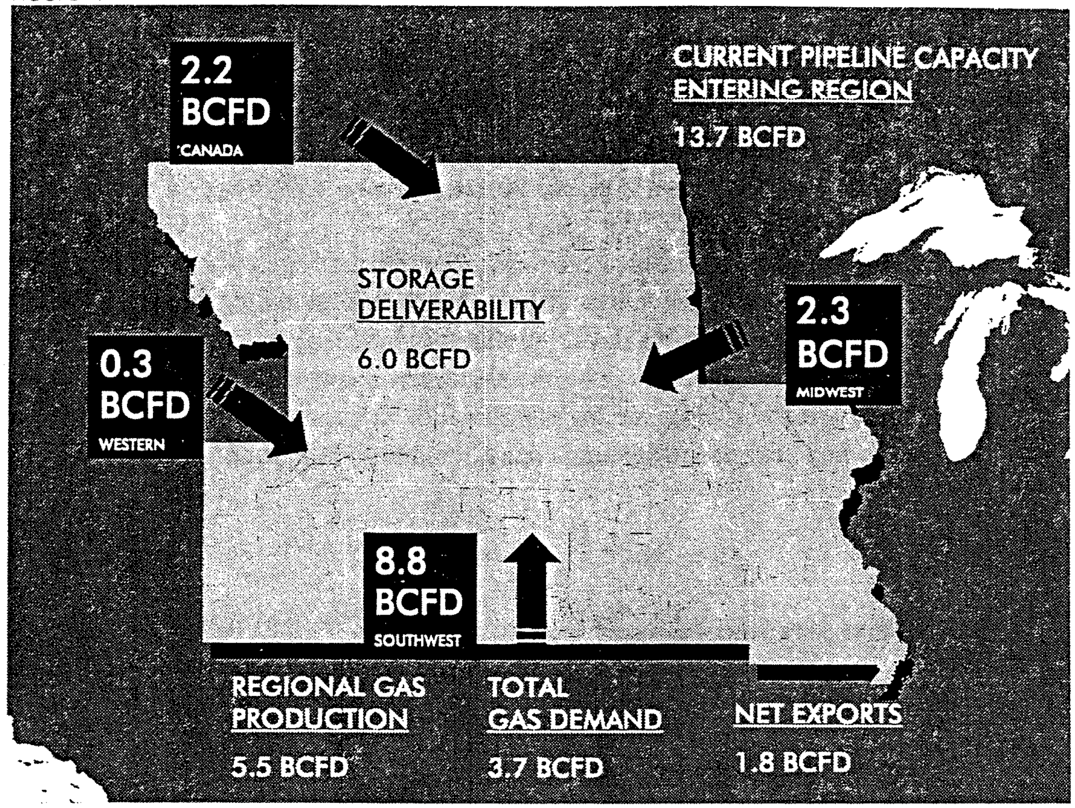
All numbers are stated in Bcfd of gas flow. Total natural gas demand and production are average daily numbers for that year, derived by taking the annual numbers and dividing by 365 days. Note that pipeline capacity and storage deliverability are designed to serve the peak-day requirements for natural gas and consequently exceed average daily gas demand. Depending on the region, peak-day gas demand can exceed average daily demand by 50% to 150%.

**U.S. GAS TRANSPORTATION REGIONS**
FIGURE 18




SOURCE: RDI SPATIAL SERVICES

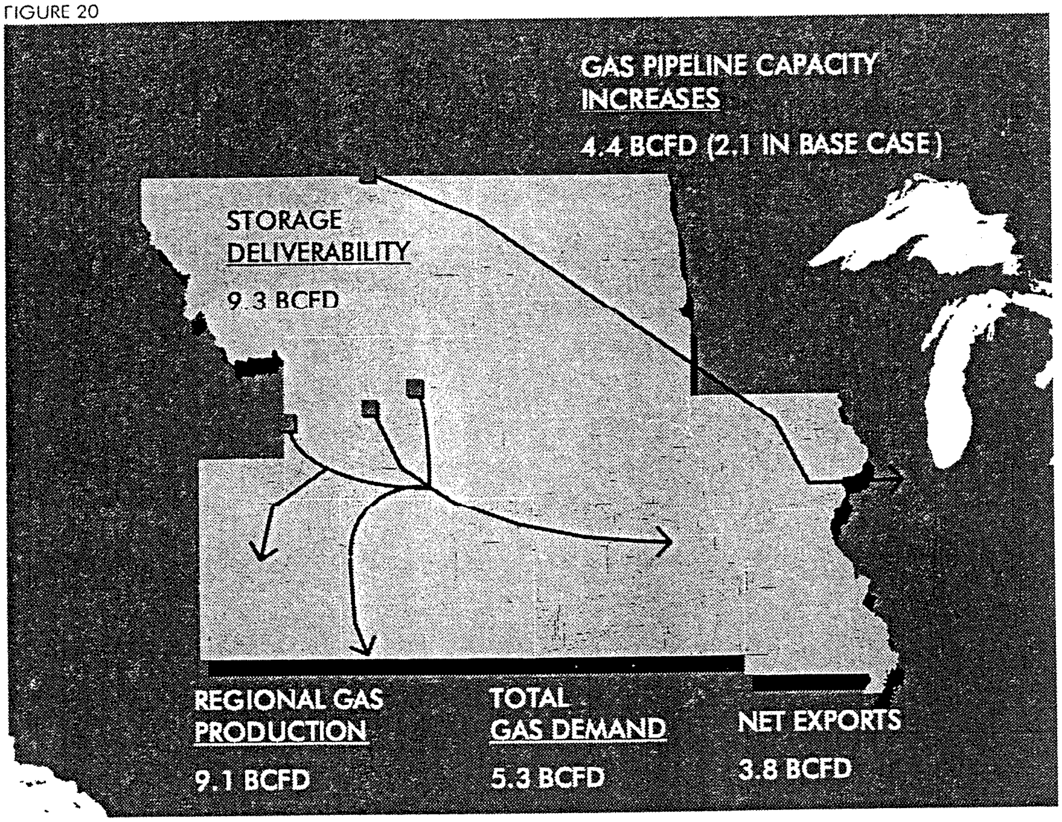
**CURRENT PIPELINE CAPACITY – CENTRAL REGION - 1998**
FIGURE 19




**Central Transport Region** The Central region is the source region for gas production from the Rocky Mountains and Kansas. The region is a net exporter of gas given that production exceeds consumption in the region by about 48%. Pipeline capacity is sufficient to meet regional demand and allow gas to flow to Midwest markets from the Southwest and Canada. Total capacity into the region is about 14 Bcfd, the majority of which allows gas to move northward from Texas and Oklahoma. Over the last several years, gas flow between the Central and Midwest regions has increased as the Pony Express and Trailblazer systems have been brought on-line.

The Central region is one of the colder regions of the country and has large peaks in space-heating gas demand. EIA reports 1996 peak-day levels of over 10 Bcfd. The region has large storage facilities in Montana, Utah, Colorado, and Kansas. Storage in this region is primarily designed to hold excess production rather than serve as supply to local markets.

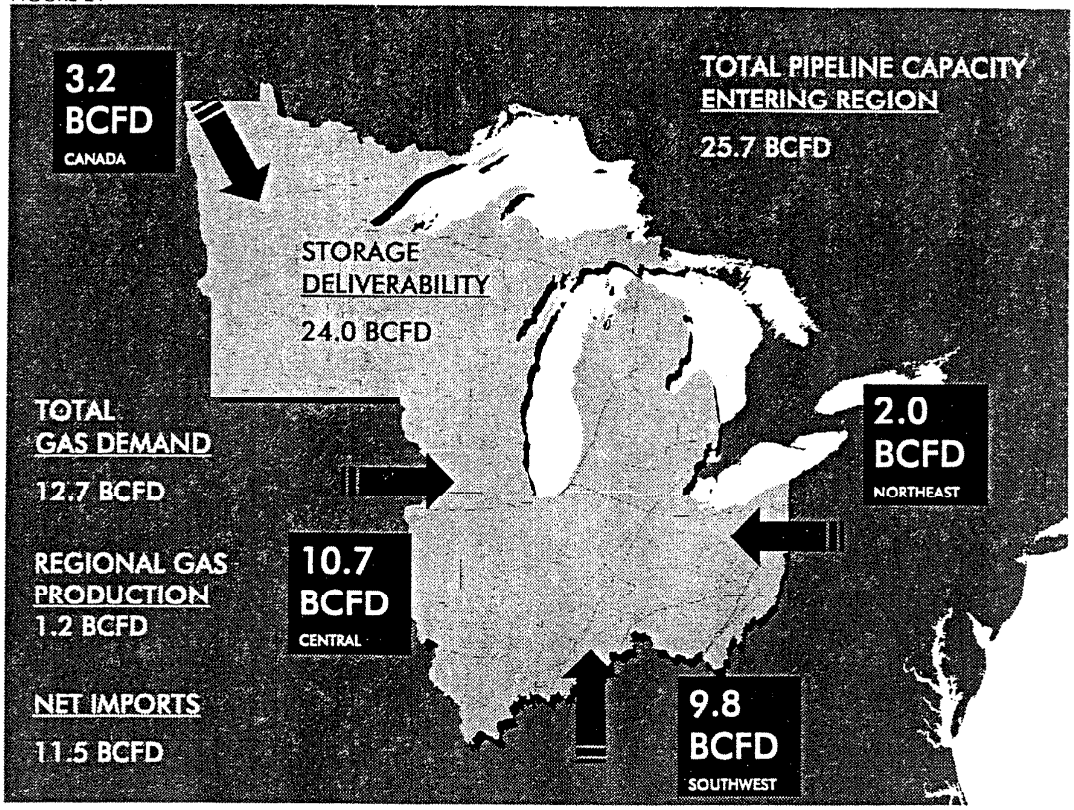
**IMPACTS ON THE CENTRAL REGION–MODERATE CASE - 2010**
FIGURE 20




With Kyoto implementation, gas transportation capacity would be forced to grow in the Central region as production increases from Rocky Mountain sources. Daily production would almost double by 2010 in the Kyoto cases, as would gas exports from the region. Average daily gas demand would increase to 5.3 Bcfd in the Moderate Case and as high as 5.7 Bcfd in the High Case, which compares with 4.6 Bcfd projected for 2010 in our Base Case.

Most of the pipeline projects in this region are designed to free up those supplies so they can enter either Western or Midwest markets. In the Kyoto cases, expansions would primarily occur on Wyoming-based systems, Trailblazer, and other KN interstate zones. A 0.9 Bcfd expansion of Northern Border and Natural Gas Pipeline Co. of America (NGPL) into Chicago is projected in 2007 to increase Canadian imports. These pipelines were already expanded in 1998. Several expansions of the Northern Natural system are required after 2010. Storage deliverability is also projected to increase to handle increases in gas production.

CURRENT PIPELINE CAPACITY - MIDWEST REGION - 1998
FIGURE 21

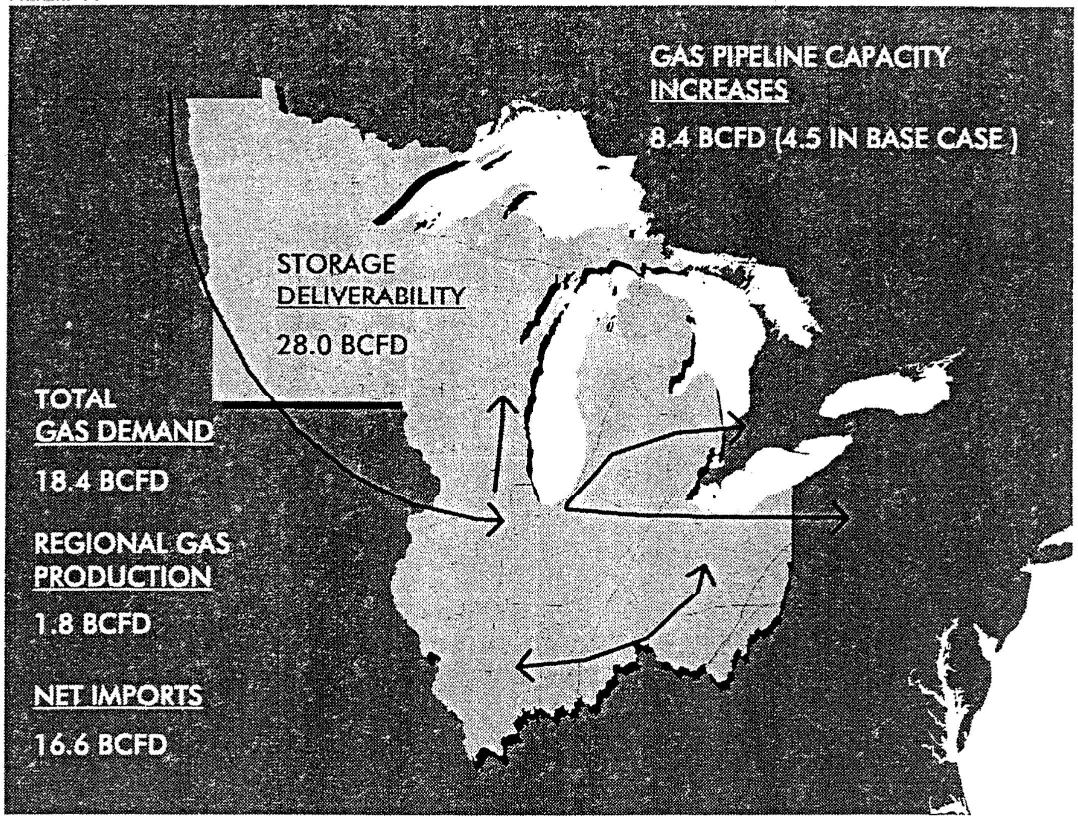



**Midwest Transport Region**

The Midwest region is a large importer of natural gas, with about 11.5 Bcfd of gas originating from outside the region. Chicago is rapidly becoming a major hub for natural gas trade as supplies from Canada increase. A second major hub in the region is located east of Detroit in Dawn, Ontario. About 25 Bcfd of pipeline capacity is currently available to move gas into the region.

The Midwest region has large seasonal heating requirements and a stable industrial gas load. Peak-day demand is estimated to be about 20 Bcfd, or 60% greater than average daily demand of 12.7 Bcfd. The Midwest region has 26 Bcfd of storage withdrawal capacity, more than any other region. Facilities are primarily located in Michigan, Ohio, and Illinois. Some of the storage capacity in the Midwest is used by customers in the Northeast market.

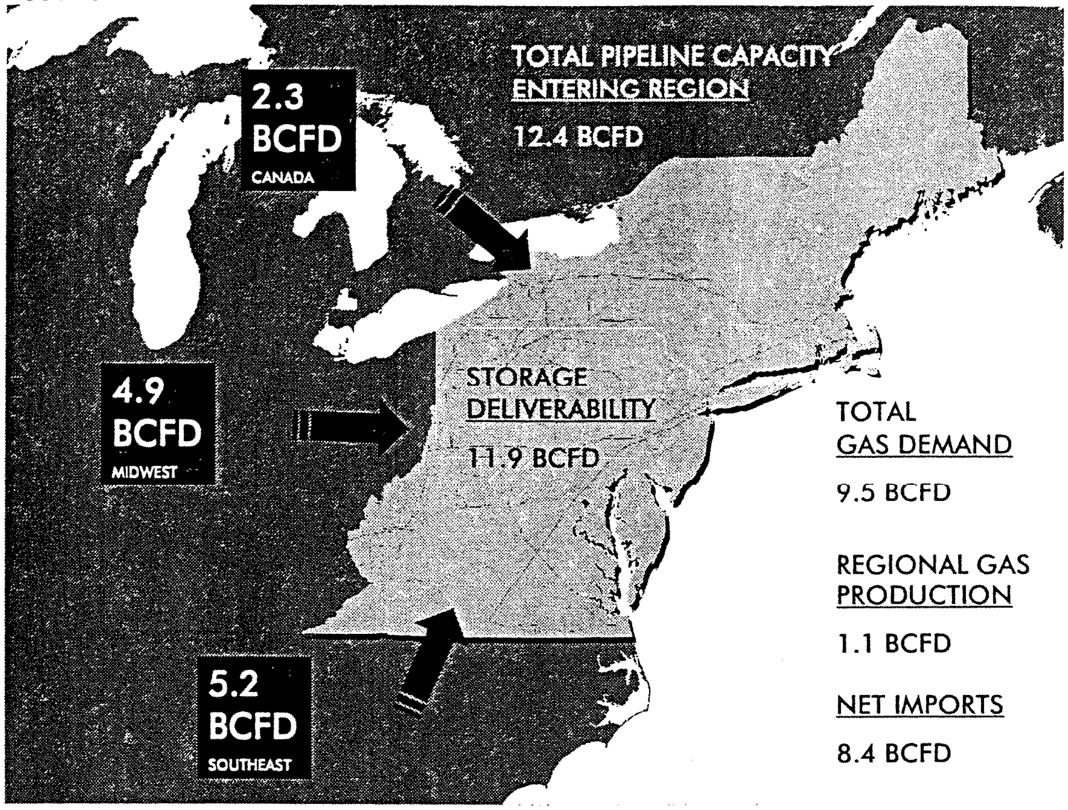
**IMPACTS ON THE MIDWEST REGION–MODERATE CASE - 2010**
FIGURE 22




In the Moderate Case, average daily demand would increase substantially, from about 13 Bcfd in 1998 to over 18 Bcfd in 2010. Average daily gas demand in the High Case would reach 20 Bcfd. This compares to 14.5 Bcfd by 2010 in the Base Case. Gas-fired generation is the primary driver of gas demand in the Kyoto cases, and baseload electric generation, coupled with strong seasonal demand, could force peak-day gas demand above 30 Bcfd in the Moderate and High Cases. Daily demand at this level may stress projected pipeline capacity as a portion of regional capacity is primarily designed to flow gas into the Northeast.

The Midwest region is heavily impacted by the Alliance pipeline project in all of the scenarios examined. In addition, the 1 Bcfd Vector project, Crossroads, and Independence are assumed to be built or expanded to move gas from the Midwest to the Northeast. In the Kyoto cases, a compression expansion is assumed to occur on Alliance in 2005. The other major interstate pipeline expansions in the region are assumed to occur on ANR's system in Indiana, Illinois, Ohio, and Wisconsin.

**CURRENT PIPELINE CAPACITY – NORTHEAST REGION - 1998**
FIGURE 23

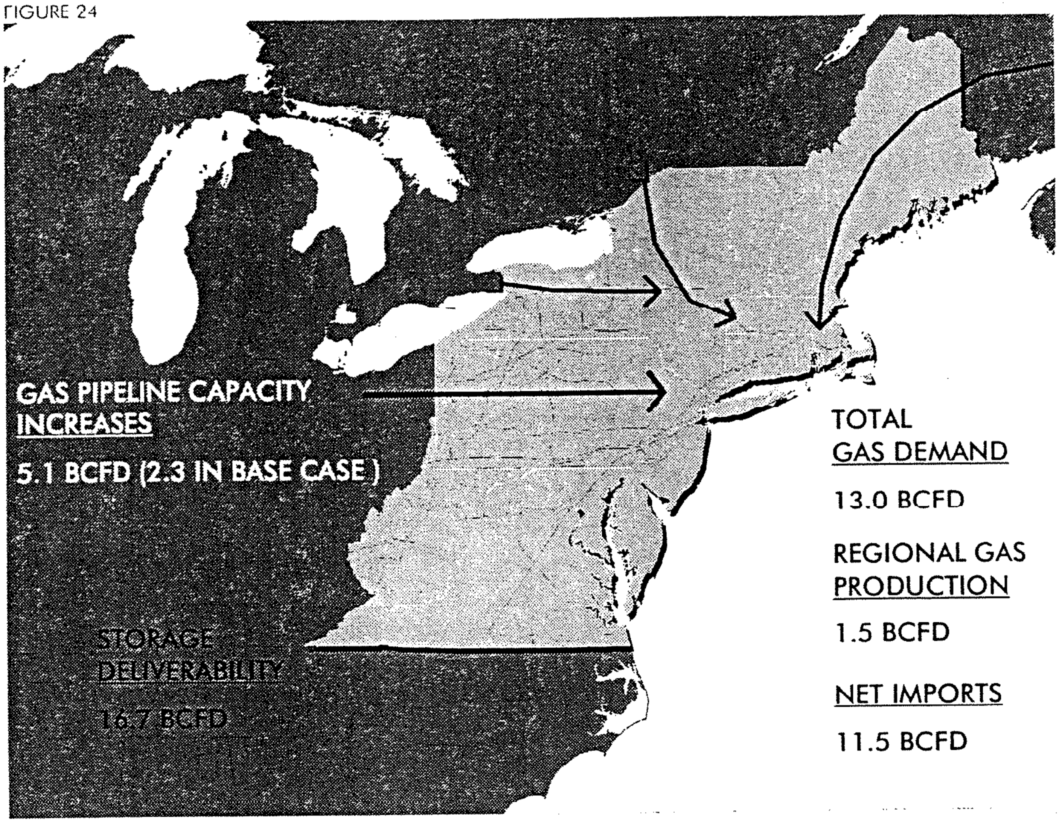



**Northeast Transport Region** The Northeast region is the most densely populated in the country and also one of the coldest. This creates high levels of winter gas demand on Northeast region pipelines. Peak-day demand is estimated to be in excess of 20 Bcfd. Like the Midwest, the region is a large importer of gas. Almost 90% of the 9.5 Bcfd of daily gas demand is met by imports into the region, and native production totals only 1.1 Bcfd. Storage withdrawal capability is estimated to be about 11.9 Bcfd. Most of the storage locations and gas wells are located in the western half of the Northeast region. Gas storage is vital in this region to meet peak period needs.

The Northeast region is the focus of several major expansions over the next few years, including Millennium, Tennessee Eastern Express, Maritimes and Northeast. The Maritimes system extends from Nova Scotia and will connect into the Tennessee pipeline in Massachusetts through joint facilities owned by Maritimes and Portland Gas Transmission. These in turn extend from Northern Massachusetts to the Canadian border.

**IMPACTS ON THE NORTHEAST REGION–MODERATE CASE - 2010**

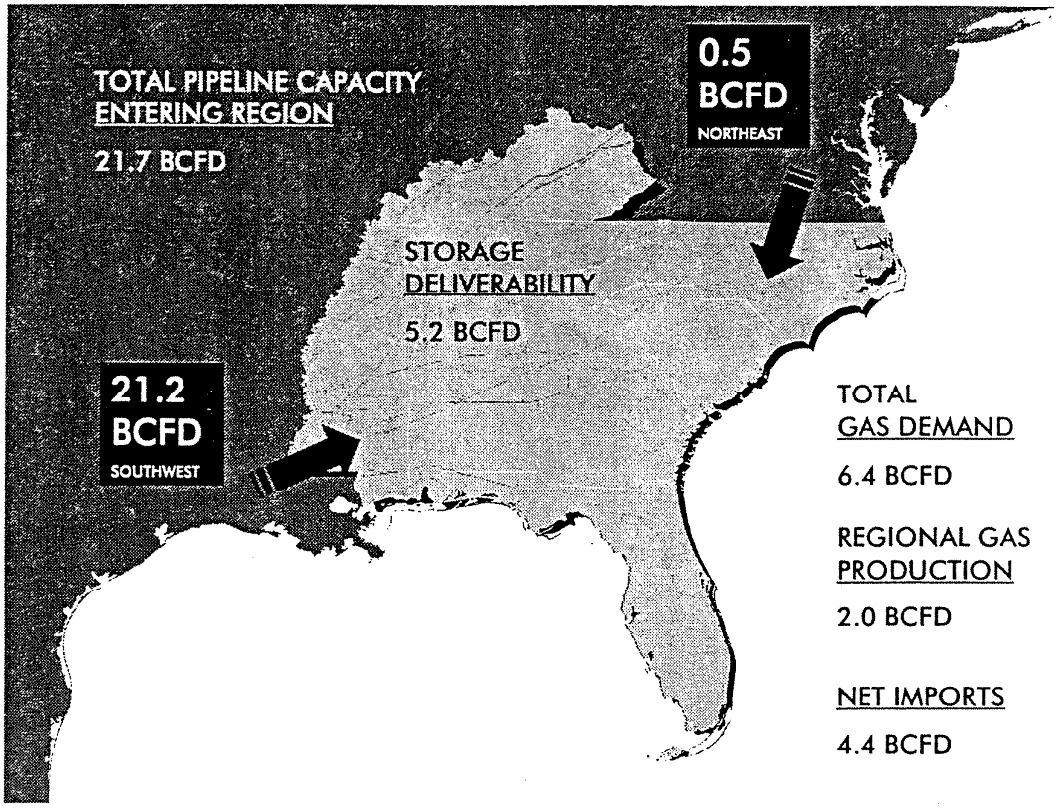
FIGURE 24




Under the Kyoto cases, most of the new capacity into the Northeast would allow access for new Canadian supplies. Expansions are projected to occur on Iroquois in upstate New York, Tennessee at Niagara Falls, and Maritimes from Sable Island. Average daily gas demand would reach 13 Bcfd in the Moderate Case, compared to 11 Bcfd in the Base Case by 2010. Storage deliverability is projected to increase by more than 4 Bcfd.

It should be noted that most storage capacity is located in the western portion of the region, while the load centers are on the Atlantic seaboard, making cross-regional capacity important. This is intensified by the fact that many developers are currently opting away designing new gas power plants with duel-fuel capabilities, which makes pipeline capacity even more critical to electric service reliability.

**CURRENT PIPELINE CAPACITY – SOUTHEAST REGION - 1998**
FIGURE 25

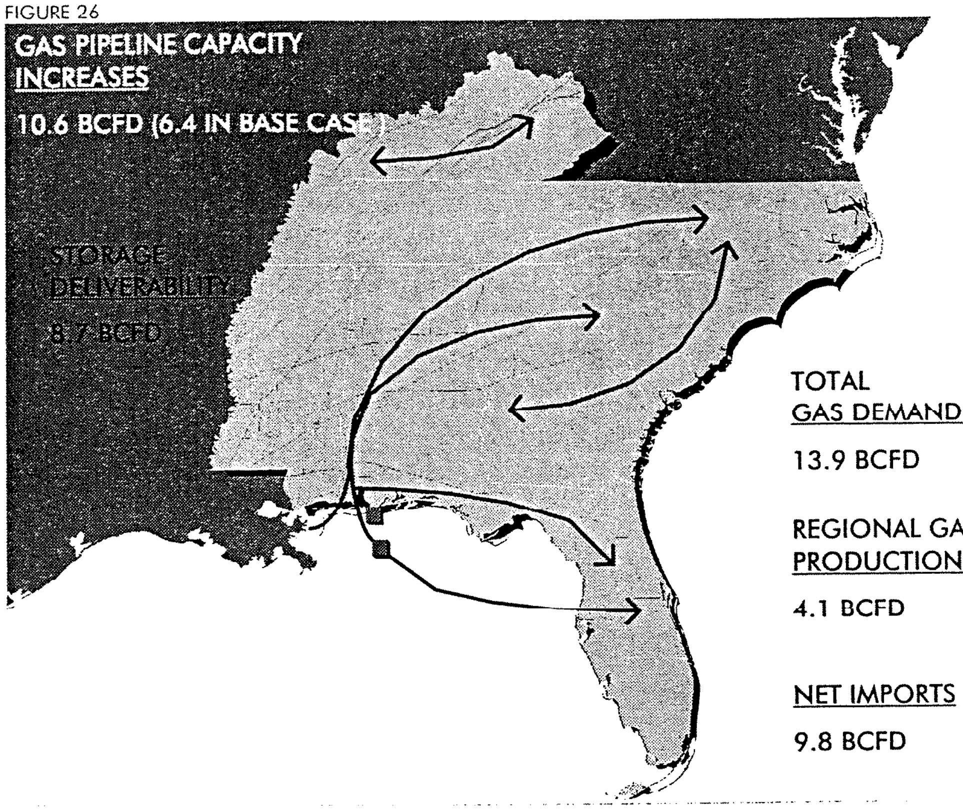



**Southeast Transport Region** Current gas demand in the Southeast region is about 6.4 Bcfd. Demand is anchored by gas use in the industrial sector. Weather conditions in the region are generally mild such that swings in residential and commercial demand are minimal. Peak-day demand is estimated to be only 50% greater than average demand. The region currently has very low gas demand for electric generation, but growth in that sector will make up the bulk of overall gas demand growth in the years ahead.

The Southeast region currently receives most of its gas from the Southwest region, and much of the pipeline capacity in the region allows supplies to flow to the Midwest and Northeast. Four pipelines make the bulk of interstate gas deliveries in the region: Transco, Southern Natural (Sonat), Florida Gas Transmission (FGT), and Tennessee. Storage deliverability is relatively limited, but a majority of facilities in the region are salt-canyon storage sites, which have much higher deliverability rates than conventional depleted field storage.

**IMPACTS ON THE SOUTHEAST REGION–MODERATE CASE - 2010**

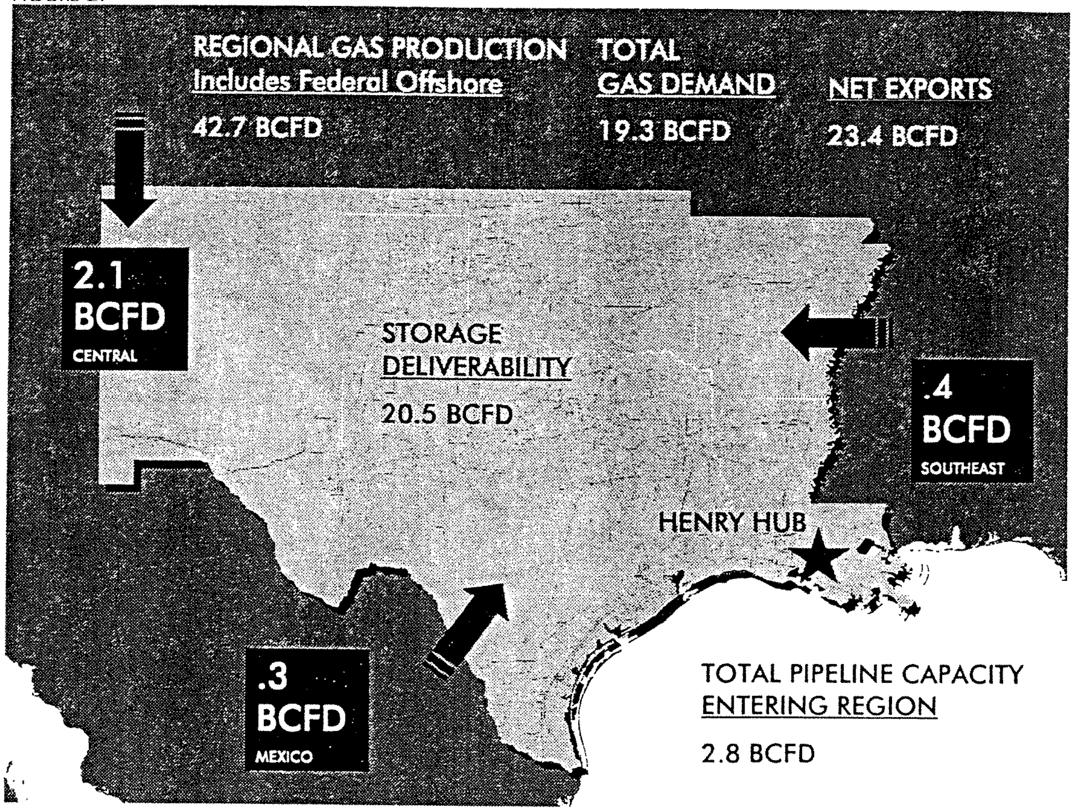
FIGURE 26




The Southeast would be heavily impacted by the Kyoto Protocol, but the region would also require significant pipeline expansion in our Base Case. Total gas demand would increase to 14 Bcfd in the Moderate Case, and reach 15.5 Bcfd in the High Case in 2010. This compares with a Base Case projection of 10 Bcfd.

In our Base Case, a variety of pipeline expansions will occur between 2000 to 2010, including major expansions for FGT, Transco at Mobile Bay, Alabama, and the mainline through Georgia and the Carolinas. Each pipeline is expected to add more than 1 Bcfd by 2010. Expansions are also projected for Columbia Gulf, which will provide gas to Tennessee Valley Authority (TVA) electric generation projects. Under Kyoto, additional expansions greater than 600 million cubic feet per day (MMcfd) are projected for both Transco and Sonat. One controversial project included in our Base Case is an expansion from the offshore Gulf to Florida. RDI includes a 600 MMcfd expansion from the Gulf in 2004 as an alternative to continued expansions to FGT. This project hinges on Florida regulatory approval.

**CURRENT PIPELINE CAPACITY – SOUTHWEST REGION – 1998**
FIGURE 27

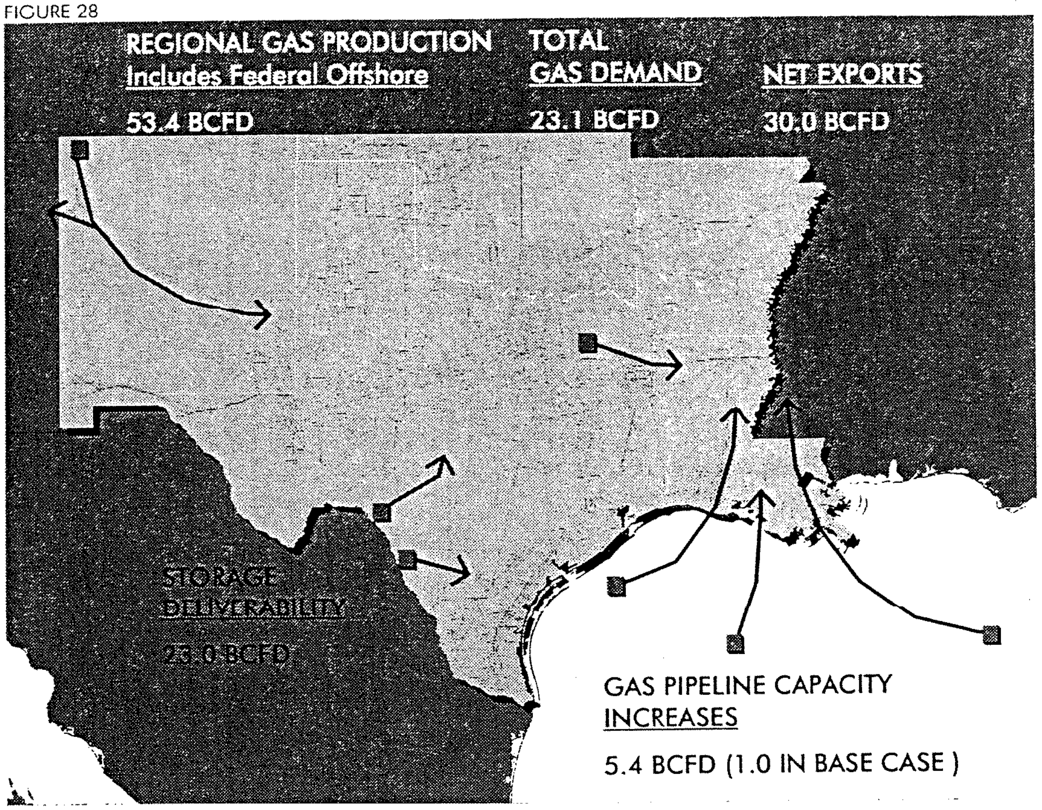



**Southwest Transport Region** The Southwest is the primary gas supply region for the country. Multitudes of interstate and intrastate pipeline systems cross the region. Most gas consumption in the region is supplied by intrastate pipeline systems, while the interstate systems are primarily used for interregional transport. For that reason, capacity entering the region is small. The exception is capacity to allow gas to flow from Western Colorado into the San Juan Basin of New Mexico.

Average daily gas demand currently exceeds 19 Bcfd, making it the largest gas-consuming region in the country. Demand is driven by a high proportion of gas-fired electric generation. In addition, industrial gas load, primarily the petrochemical industry, constitutes about half of total demand. The Southwest has more than 20 Bcfd of storage deliverability. Many of these storage facilities are linked to market hubs like Henry Hub, Louisiana. This hub is a primary market point for the gas business and the delivery point for the New York Mercantile Exchange (NYMEX) natural gas futures contract.

**IMPACTS ON THE SOUTHWEST REGION–MODERATE CASE - 2010**

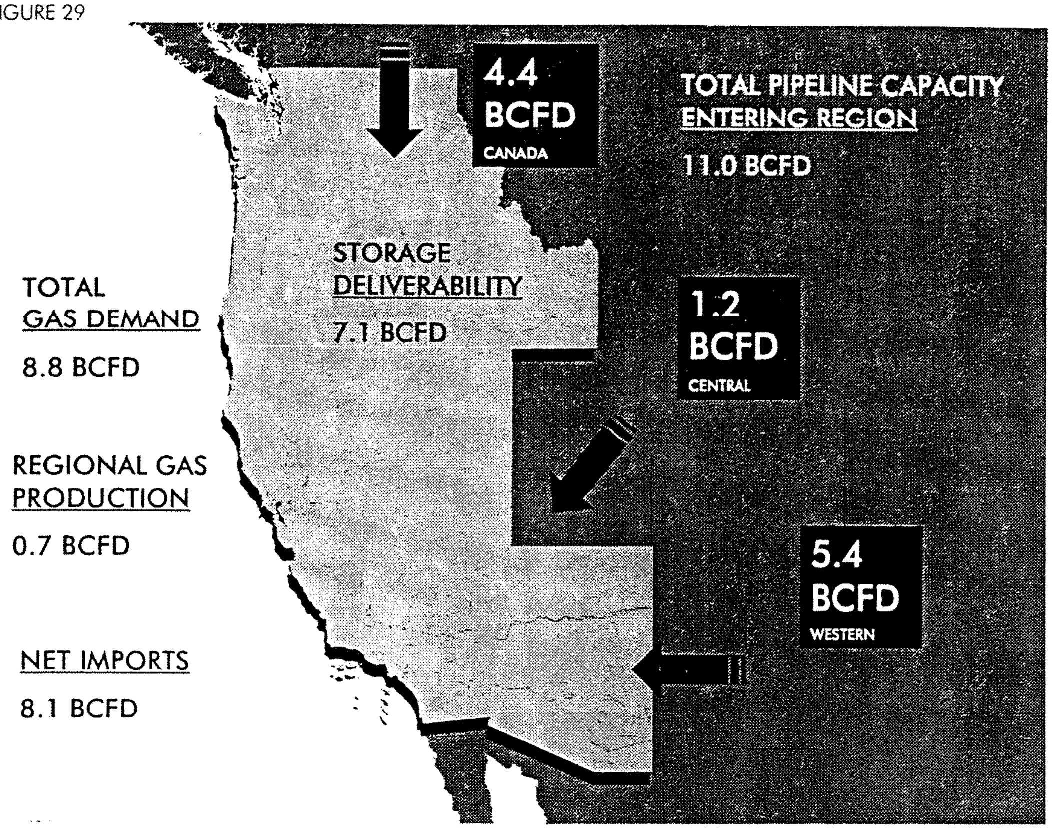
FIGURE 28




Southwest gas production would increase from current levels of about 43 Bcfd to more than 53 Bcfd by 2010 under the Moderate Case and 57 Bcfd under our High Case. This is significantly higher than the 49 Bcfd forecast by 2010 under the Base Case. As discussed in the gas supply section, the majority of this additional deliverablity must come from the offshore Gulf areas. As a result of these production increases, most of the expansions forecast in the Southwest are related to releasing offshore Gulf production. In the Kyoto cases, the expansions occur on some of the longest pipelines in the country. ANR, Tennessee, and Texas Eastern all expand connections to the Gulf. In the Permian, or West Texas, region Northern Natural and Transwestern are projected to expand capacity.

Projected Kyoto gas demand in the region displays an interesting dynamic. During the projected transition to carbon reductions, the steam turbine units would dispatch at high utilization rates and gas demand would surge. However, demand would wane in later years as the less efficient steam units are replaced with increasingly efficient gas combined-cycle generation.

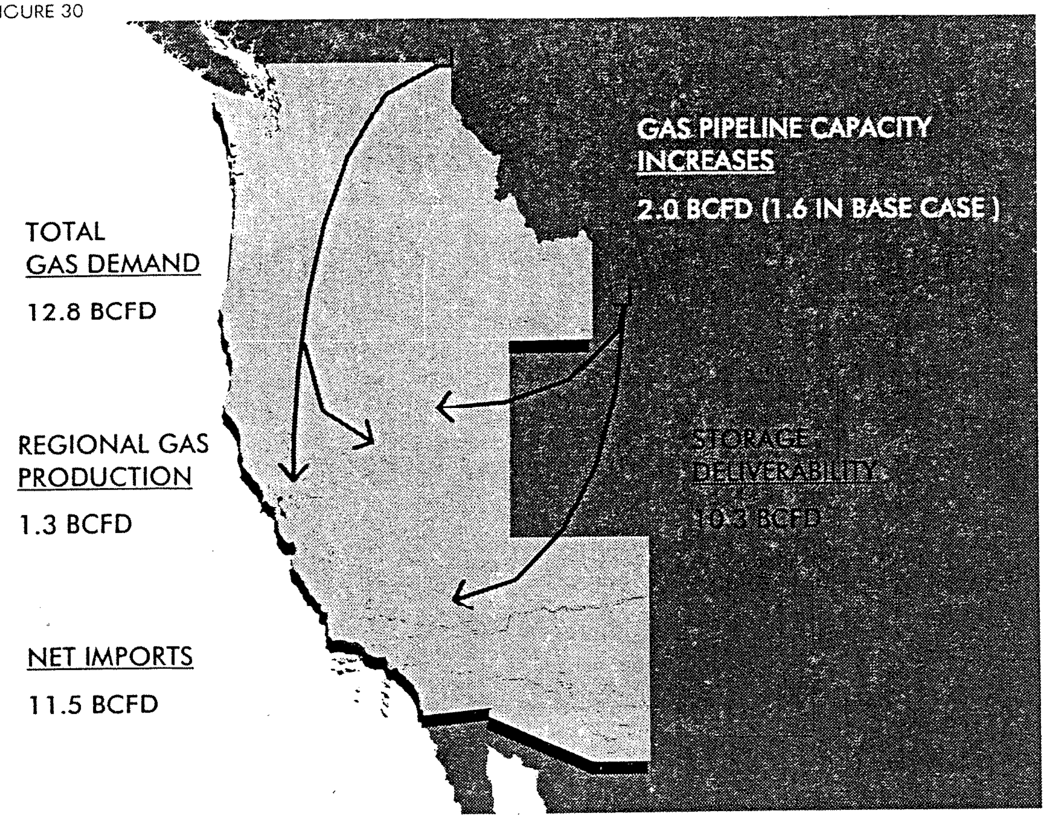
**CURRENT PIPELINE CAPACITY – WESTERN REGION - 1998**
FIGURE 29




**Western Transport Region** Natural gas is widely used in the Western region as a result of environmental initiatives legislated by California. Under these initiatives, fuel oil use is restricted for power generation while gas is used year round. High population levels in California also drive strong residential and commercial gas demand. Average daily gas demand in the Western region is 8.8 Bcfd. Demand is almost totally met by gas supplied from pipeline imports.

Almost half of the pipeline capacity for the region moves gas sourced from Canada. Supplies from the Rocky Mountains, the San Juan Basin, and West Texas provide the balance of Western gas imports. The region was the focus of several new pipeline projects in the early 1990s that increased capacity from Canada on PG&E Gas Transmission-NW (PGT) and from the Rockies on Kern River. These projects have generally left the Western region with excess pipeline capacity for the time being.

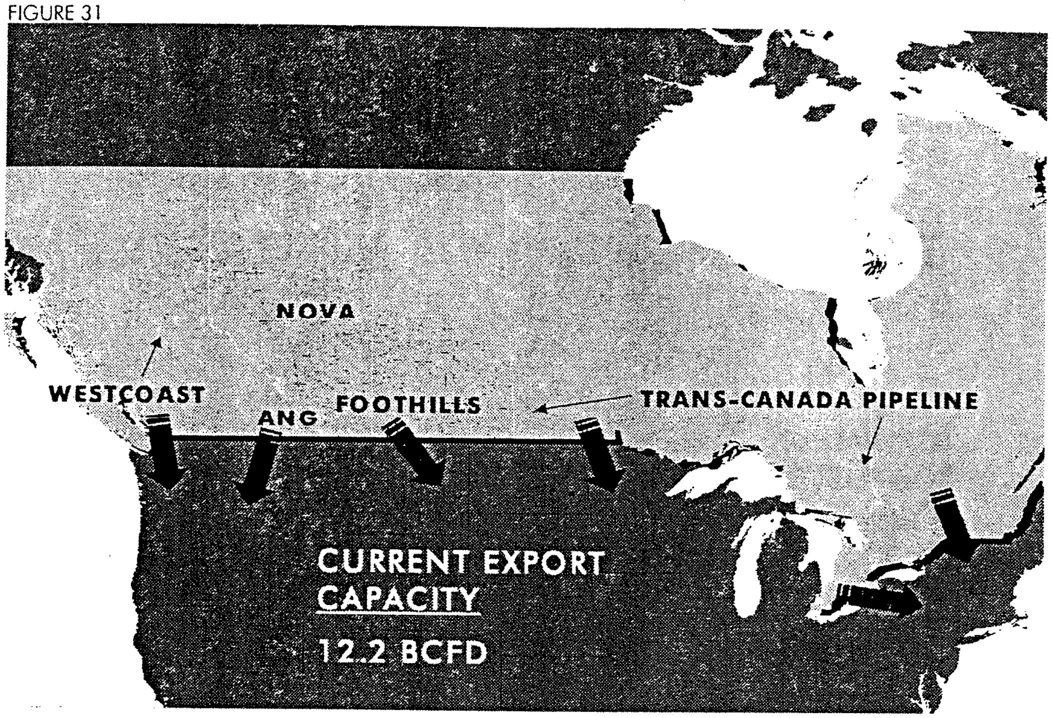
**IMPACTS ON THE WESTERN REGION–MODERATE CASE - 2010**
FIGURE 30




The Western region is the least affected area in RDI's projections because it already has surplus pipeline capacity and already relies on natural gas (along with hydropower) for much of its generation needs. Nuclear units are retired and replaced by gas in our Base Case, but given life extensions in the Kyoto cases. The end result is that nearly as many pipeline expansions occur in our Base Case as in the Kyoto cases. In our Base Case, two new pipelines are proposed out of the Rockies and the San Juan basin -- Southern Trails, a 140 MMcfd converted oil line that flows from New Mexico to Long Beach, California and Ruby pipeline, a 250 MMcfd system from Western Colorado through Nevada.

Carbon reductions under the Kyoto Protocol would tend to pull San Juan and Rocky Mountain gas supplies eastward for use by Midwest and Central electric generators. This diversion would require expansions along PGT. In the Moderate and High Cases, 0.9 and 1.7 Bcfd of capacity, respectively, would be added on PGT over the forecast period. Our analysis assumes static hydroelectric availability, but dam removal could increase the pressure on gas capacity requirements.

**MAJOR CANADIAN PIPELINES**
FIGURE 31




**Canada** Canada plays a major role in satiating U.S. demand for natural gas in all of the scenarios examined by RDI. Current imports of 9 Bcfd are projected grow to 12 Bcfd under our Base Case. Under the High Case, Canadian imports increase by about 7 Bcfd by 2010, or more than twice our Base Case growth. The Low and Moderate Cases are projected to grow by 5 and 6 Bcfd, respectively, by 2010.

Kyoto Protocol compliance would drive U.S. consumers to increase reliance on Canadian natural gas. Current pipeline export capacity from Canada is about 12.2 Bcfd and should increase to over 18 Bcfd by 2010 in our Base Case. To bring sufficient gas volumes to market under Kyoto, massive expansions of Canadian pipeline capacity equivalent to about 2 Bcfd per year, or three Alliance pipelines, would be necessary between 2005 and 2010 in the Moderate and High Cases. In both of these cases, Canadian export capacity grows to about 23 Bcfd by 2010. To achieve this, a variety of expansions within Canada must occur. The NOVA pipeline system in Alberta is projected to expand by more than 3 Bcfd by 2020 in the Base Case. In the Moderate and High Cases, more than 3 Bcfd of capacity is needed by 2005 or 2006. Other expansions include the Canadian portion of Alliance Foothills (the connection to Northern Border), ANG (Alberta Natural Gas, the connection to PGT), and a major expansion to Trans-Canada pipeline in 2008.

More than 80% of Canada's current electricity production is generated by non-fossil fuel sources, primarily hydro and nuclear power. Natural gas use in Canada primarily revolves around residential-commercial space heating and industrial applications. Gas use in electric generation should also grow as combined cycle plants in Ontario and the Atlantic provinces serve electricity demand growth. RDI assumes one major hydro capacity addition in Quebec in 2007 and continued use of Ontario's nuclear capacity in the Base Case. Because Canadian's don't have the same level of reliance on fossil fuel sources as the U.S., Kyoto Protocol compliance should require significantly lower levels of fuel switching between coal and gas.

Our Base Case calls for internal Canadian total gas demand to grow from current levels of about 3.0 Tcf at 1.8% per year to 3.5 Tcf in 2010. In the Kyoto Cases total gas demand is projected to grow at a faster pace in the range of 2.1% to 2.5% per year to 2010. Therefore, a portion of new pipeline capacity, at least 1.8 Bcfd, should be required to serve internal Canadian demand by 2010. These expansions are assumed to occur on Trans-Canada pipeline.

**A CHALLENGE**

The Kyoto Protocol would place high levels of stress on the North American natural gas pipeline and storage infrastructure. A variety of projects would be necessary across the continent, most within the period 2005-2010. The uncertainty of having adequate pipeline capacity would be compounded by the fact that many potential problems come to light only as a project is underway. **Given sufficient time, the pipeline industry could successfully expand infrastructure, but concerns such as the current requirements for environmental review, landowner objections to pipeline and compressor station siting, and unresolved contractual issues within the industry would make it difficult to achieve the required levels of infrastructure expansion on schedule.**

A timely case study is the 460 MMcfd Maritimes and Northeast pipeline. The pipeline project is designed to draw on gas production from new field development at Sable Island off the coast of Nova Scotia, transporting it to markets in the Northeast U.S. The president of the Duke Energy subsidiary building the pipeline has stated that "setbacks are typical for a project of [Maritimes'] scope."[24] As the pipeline has been under construction it has faced contracting and local opposition problems. Earlier in 1999, project lenders became nervous demanding payments

[24] "Gas Pipeline Struggling toward Start." *Wall Street Journal.* May 12, 1999.

one year in advance from those potential shippers that do not have "investment grade" credit. This resulted in a reduction in the planned pipeline capacity for a time. Next, landowners' advocate, the GASP coalition, questioned the need for the project. GASP stated, "[Supporters of the project] still expect landowners and others who care about the environment to tolerate the tearing up of mile after mile of countryside in anticipation of the possibility that if Maritimes is allowed to build it, the customers will come."[25] As the pipeline neared completion construction delays occurred and testing found several leaks that were repaired. This forced the start-up date back one-month. Most recently, the National Energy Board (NEB) has decided to delay the start-up of the pipeline until issues with Canadian natives are sorted out. An Eastern Canadian tribe, the Mi'kmaq, has raised environmental and archaeological issues, requesting $100 million in compensation.[26]

Similar stories can be found on most major pipelines that have been proposed in the U.S. in recent years. In other examples, the Independence Pipeline project through Ohio received a record number of landowner complaints, and construction was delayed on a small pipeline project in North Alabama as a result of environmental concerns. PNGT in New England was fined nearly $1 million dollars by the U.S. Department of Labor's Occupational Health and Safety Administration (OSHA), as a result of construction practice violations. Pipeline contractors argue that OSHA is scrutinizing pipeline projects more closely, holding pipeline projects to the standards that other construction sites must follow. But pipeline builders maintain it is not possible to hold those standards given the limited rights-of-way in which contractors operate. The contractors subsequently assert that strict adherence to OSHA standards could lead to higher construction costs and dramatic increases in the time it takes to complete projects.[27]

Clearly, pipeline construction is not simply a matter of corporate will, and even a national commitment to the Kyoto Protocol would not put every facet of society and the regulatory community "on the same page." The forces that increasingly oppose pipeline construction today would be around under any Kyoto Protocol scenario and would form a major obstacle to the rapid and seamless expansion required for compliance.

[25] "GASP Jumps into the Fray over the Need for Maritimes and Northeast Project." *Inside FERC.* April 5, 1999. P. 15.
[26] "NEB puts Maritimes and Northeast debut on hold." *Gas Daily.* Nov 1, 1999. P.1.
[27] "Pipeline Contractors caught between FERC, OSHA on Right-of-way rules." *Inside FERC.* April 12, 1999. P.2.

# Natural Gas Prices

## INTRODUCTION AND KEY FINDINGS

A growing body of analysis points to vastly higher fuel and power prices under any Kyoto Protocol compliance scenario. This study adds to that analysis by finding that natural gas prices under the Moderate and High Cases would rise by about one-third above the Base Case in 2010, without considering the cost of carbon associated with gas combustion. Wholesale non-firm electricity prices would rise by a factor of three in the High Case. Therefore, compliance with the Kyoto Protocol would be not only difficult to achieve, but also very costly. Key findings include:

- U.S. average annual prices for natural gas delivered to power plants are forecast to escalate by 2% per year through the forecast period. Prices reach $2.86 per million Btu (mmBtu) in constant 1997 dollars by 2010 in the Base Case. High and Moderate case market dynamics would force prices to levels 26% to 32% above the Base Case in 2010. These price projections do not include the cost of carbon credits.

- Gas prices at Henry Hub would increase in the Kyoto cases as the costs of gas production climb. Beginning in 2005 gas prices are forecasts to rise by more than 6% per year, climbing past $3.00 mmBtu by 2010 of the Moderate and High Cases. In the Base Case gas prices at Henry Hub are forecasted be $2.40 mmBtu in 2010. Annual growth is projected to increase at 1.2% per year from 1998 to 2020 in the Base Case.

- Natural gas prices drive electricity prices under all of the scenarios, including the Base Case. RDI projects electricity prices to rise by 22% between 1998 and 2010 under the Base Case, but are 187% and 120% higher than the Base Case under the Moderate and High Cases.

## OVERVIEW

Implementation of the Kyoto Protocol would create tremendous tension between supply and demand in the gas market. The mechanism that would resolve that tension is price. Price ensures that supply and demand balance in each period and provides a measure of value. In a Kyoto Protocol world, natural gas would gain in value as a result of both tighter supplies and the carbon disadvantage attached to coal, currently the nation's lowest cost fossil fuel.

**Higher gas prices under the Kyoto Protocol would be doubly significant for consumers, who would pay more for both gas and electricity.** This is because gas generation would set the marginal cost of electricity supply under all of the scenarios projected by RDI, including the Base Case. The effect would be greatly amplified under the Kyoto Protocol since the factors that typically keep gas prices in check, particularly oil and coal prices, would be neutralized by high carbon costs. Alternatives to gas would largely be limited to investment in energy efficiency.

Nevertheless, gas price increases would not be a function of only competition. Rising production costs, driven by the strains of keeping pace with skyrocketing demand, would also play a major role. Factors such as higher levels of well completions, deeper drilling depths, and production decline rates would all contribute to higher gas production costs.

## GAS PRICE FORECAST: DELIVERED TO POWER PLANTS

Gas prices under the Kyoto Protocol in 2010 could be 40% higher than Base Case projections. The price of natural gas in real terms is expected to grow at about 1.6% per year through 2020 in the Base Case.[28] Figure 32 shows the U.S. annual average natural gas price delivered to power plants for our Base Case and the Kyoto cases. These gas prices do not include the cost of carbon since those costs are captured in the cost of generation and vary by plant efficiency.

The Base Case gas projection shows prices rising to $2.86/mmBtu in 2010, a 2% annual increase. In the Moderate and High Cases, gas prices would jump to $3.77 and $3.60/mmBtu, respectively, in 2010. This represents a 32% and 26% increase over Base Case levels in the same period. Furthermore, annual price increases would average about 6.4% per year between 2005 and 2010 in the Moderate and High Cases. Price increases in the Low Case are expected to reach $3/mmBtu by 2010.

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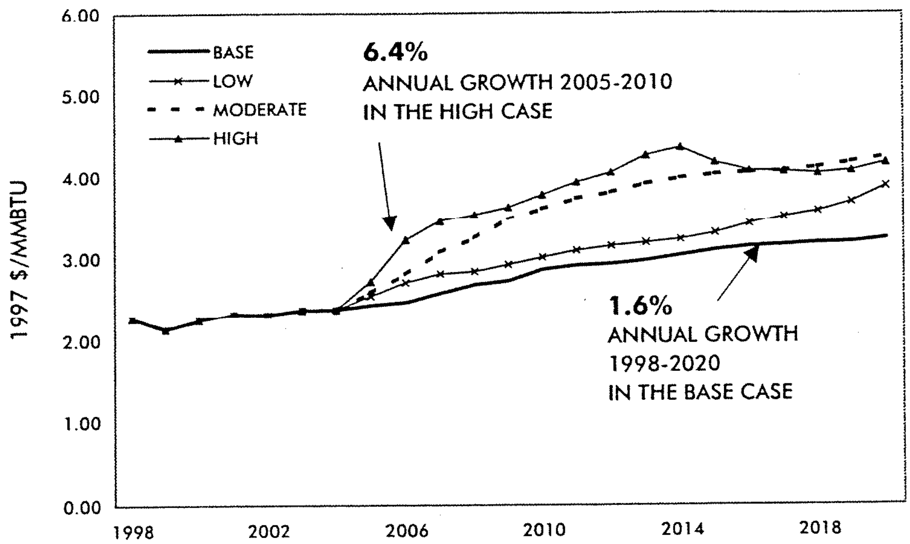
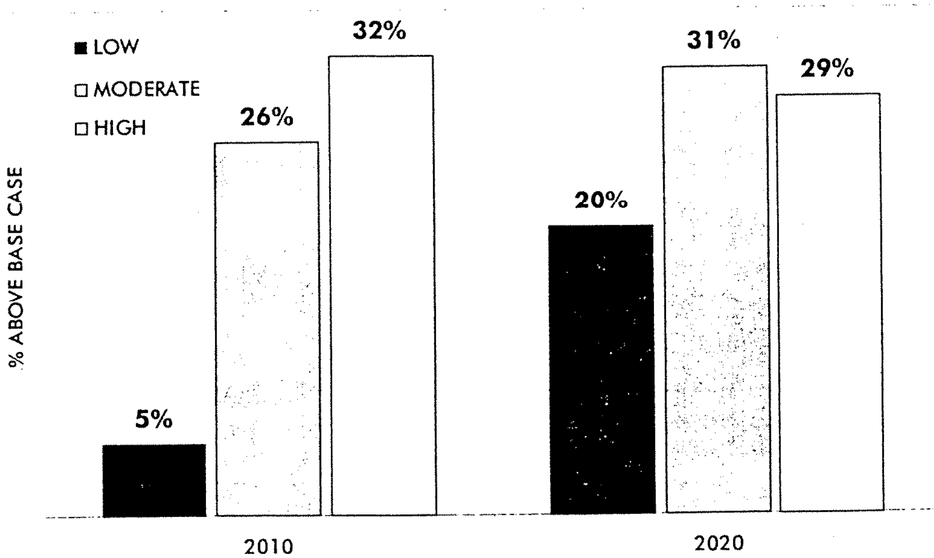
[21] All prices are reported in real terms in 1997 dollars per mmBtu.

**PROJECTED NATURAL GAS PRICES DELIVERED TO POWER PLANTS, 1998-2020**
FIGURE 32




SOURCE: RDI

**DELIVERED TO POWER PLANT PRICE INCREASES ABOVE THE BASE CASE IN 2010 AND 2020**
FIGURE 33




SOURCE: RDI

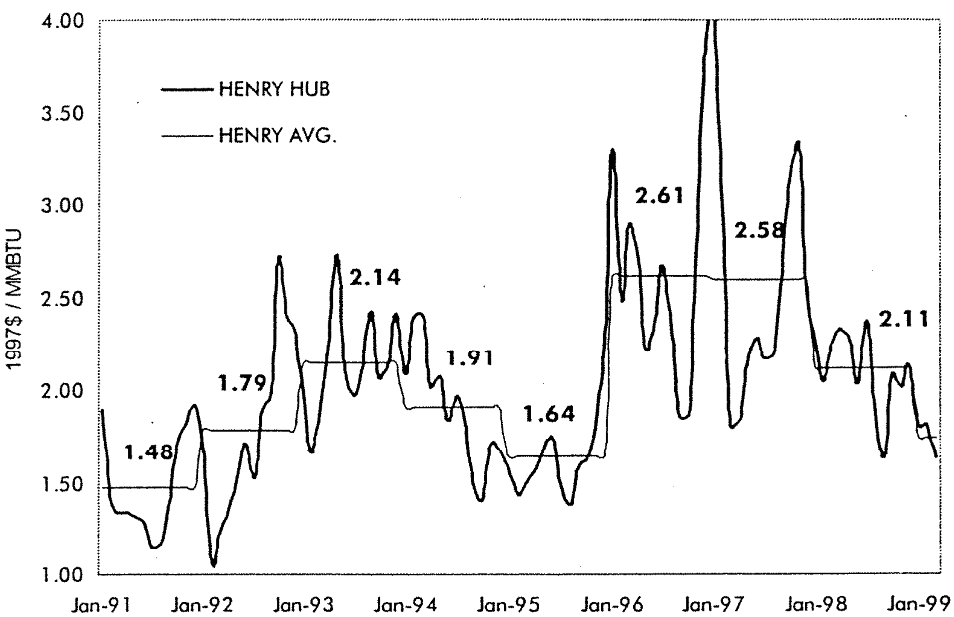
Projected gas prices in the High Case fall to levels that are near the Moderate Case by 2017. This results from the dampening of non-electric sector gas demand by very high prices. Specifically, High Case gas demand would be so strong that projected peak prices of $4.35/mmBtu in 2014 would be necessary to stimulate additional supply. These high prices would also force some industrial and residential and commercial consumers out of the market, allowing the market to soften in later years.

Price increases of this magnitude represent a substantial increase in fuel cost for electric generation. Placed in perspective, U.S. electric generators spent $8 billion for natural gas in 1998. In the Base Case, over $21 billion is projected to be spent in 2010 — 7.4 Tcf of natural gas consumed annually at an average price of $2.93 per thousand cubic foot (Mcf). This compares with 2010 costs of over $60 billion in the High Case. In addition, the price paid at the city-gate by LDCs and industrial customers would similarly increase. The final price to gas end-users in the residential and commercial sectors would increase by the additional costs of bringing gas to the city-gate and the additional retail gas service charges.

**Price Volatility** Gas prices in the past have exhibited a great deal of volatility. A variety of factors contribute to this price fluctuation -- primarily seasonal shifts in the weather, variations in gas available from storage sites, capacity constraints on pipelines, and supply-side operational difficulties resulting from hurricanes, frozen well valves, or other such events. Deregulation of the gas market has lowered average annual prices, but has also increased the level of short-term price volatility. Kyoto implementation would potentially increase short-term imbalances between gas supply and demand. This may translate into increased price volatility.

The additional uncertainty that volatility brings to the gas market should increase the need for skilled risk management. Henry Hub, Louisiana is a primary market center for gas trading and benchmarking for gas supply prices. Figure 34 illustrates the volatility of monthly gas prices at Henry Hub. Prices have been greater than $4.00/mmBtu and as low as $1.00/mmBtu, but the annual average has stayed between $1.50 and $2.50/mmBtu.

**HISTORIC GAS SUPPLY PRICES AT HENRY HUB, 1990-1999**
FIGURE 34



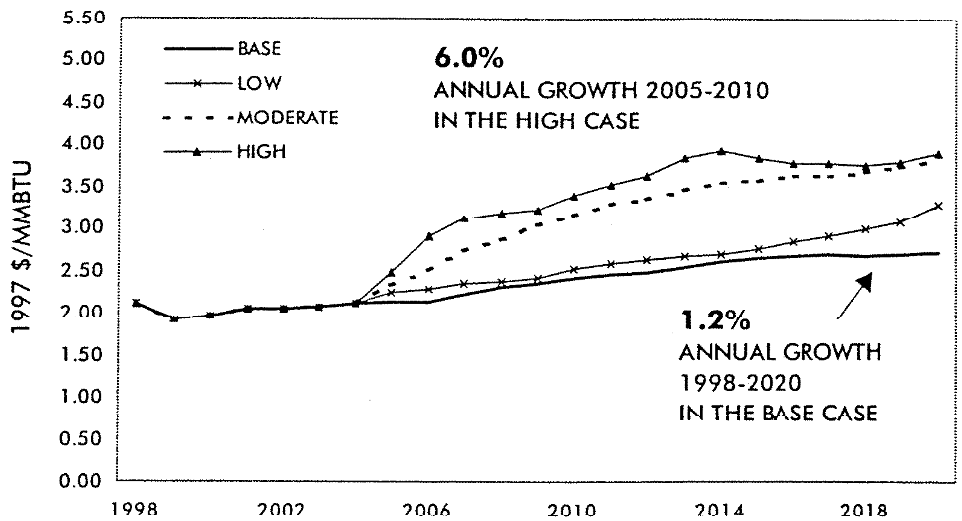

SOURCE: RDI

## GAS PRODUCER PRICE FORECAST

Figure 35 shows the long-term supply price projection at Henry Hub for our Base Case and the Kyoto cases. In our Base Case, forecast supply prices are driven down slightly in 1999 and 2000 as pipeline expansions unlock low cost Canadian supplies. The resulting gas-on-gas competition drives overall prices down. As gas demand increases when new gas-fired power plants come online, prices begin to rise. In later years, increases are also driven by higher costs of production. Prices at Henry Hub are expected to increase by about 1.2% per year in the Base Case.

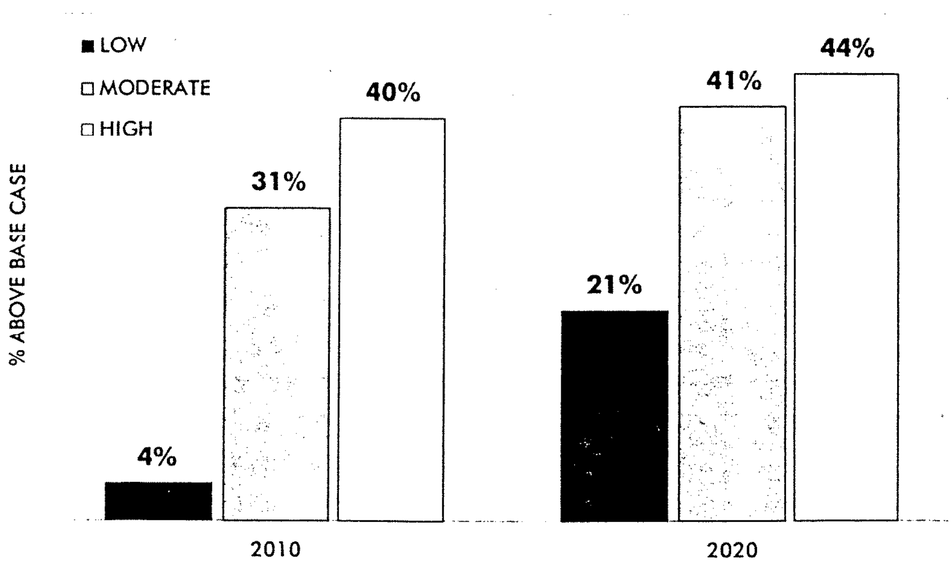
The Kyoto cases show rapid increases in supply price associated with the substantial increases in production that would be necessary to meet the surge in demand. Between 2005 and 2010, supply prices escalate at nearly 6% per year. The costs of production are increasing rapidly during this period and the value of gas to consumers has increased. These forces drive projected supply prices in the Moderate and High Cases to reach beyond $3.00/mmBtu by 2010, which is 30% and 40% above Base Case levels. Stringent carbon reductions would cause prices to reach nearly $4.00/mmBtu by 2020. The Low Case displays a price trend much closer to our Base Case trajectory.

**PROJECTED NATURAL GAS SUPPLY PRICES AT HENRY HUB, 1998-2020**
FIGURE 35



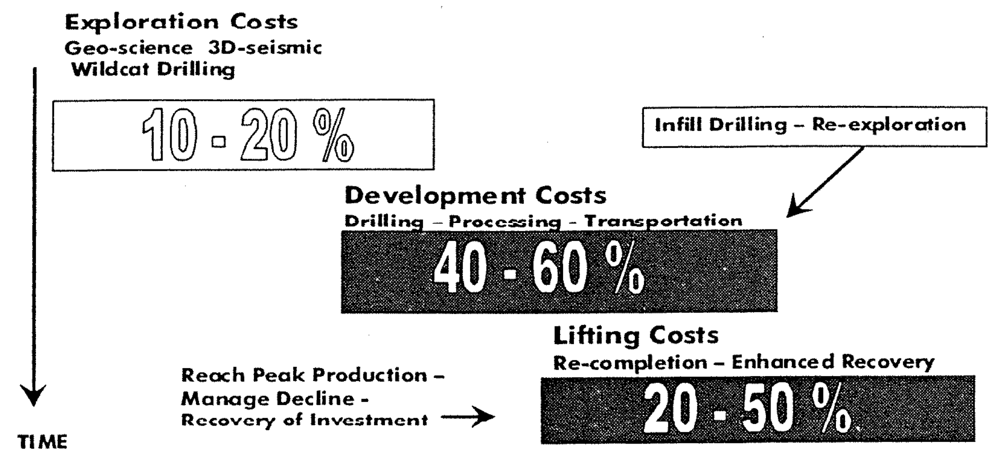

SOURCE: RDI

**HENRY HUB PRICE INCREASES ABOVE THE BASE CASE IN 2010 AND 2020**
FIGURE 36




SOURCE: RDI

COST COMPONENTS OF DEVELOPING GAS SUPPLY
FIGURE 37




SOURCE: RDI

**Gas Production Costs** A large portion of the increase in delivered gas prices occurs at the wellhead. In developing gas supply, producers spend their investment dollars on each aspect of producing gas— exploration, development, and lifting costs. See Figure 37. A large portion, often more than half, of the costs are incurred in the development phase of a project. The largest share of development cost is attributed to drilling.

Current drilling costs are assumed to average \$0.49/mmBtu for onshore production and \$0.33 /mmBtu for offshore production. In our Base Case, costs for onshore drilling remain flat as decreases in costs from better technologies are offset by increasing average drilling depth. The costs of offshore production are forecast to escalate to \$0.86/mmBtu by 2010, the result of increases in drilling activity to reach the forecasted level of production and replacing production from declines at existing wells. The costs of drilling in the Kyoto cases increase with the higher levels of industry activity. In the Moderate and High Cases, the increases in drilling activity are projected to cause onshore drilling costs to reach \$0.55/mmBtu and offshore costs to reach \$1.02/mmBtu by 2010.

# Regional Impacts

## INTRODUCTION AND KEY FINDINGS

**Implementation of the Kyoto Protocol under any of the scenarios examined by RDI would require a radical turnover and replacement of U.S. electricity generation capital stock and a dramatic increase in the consumption of natural gas – and all within ten years.** Furthermore, the effects would not be uniform across the country. While all areas would be affected, some would need to replace a sizeable portion of their generating capacity and dramatically expand pipeline capacity. Key findings include:

- By 2010, the ECAR and SERC regions of the North American Electric Reliability Council (NERC) would reduce or idle generation from at least 25,000 MW in the Moderate Case and 50,000 MW in the High Case. RDI projects that total coal-fired capacity at risk of curtailment or shut-down in the U.S. would amount to at least 130,000 MW in the Moderate Case and 220,000 MW in the High Case. Existing capacity stands at approximately 315,000 MW.

- ECAR would grow from among the lowest gas-consuming regions to become the third largest gas-consuming region by 2010 under the Kyoto cases. RDI projects that the ECAR gas-fired generating capacity will reach 16,925 MW under the Base Case, but would expand 88% further, to 29,924 MW, under the High Case.

- In 1998, only ERCOT consumed more than 1 Tcf in total gas demand. By 2010, RDI projects that SERC and WSCC will also exceed 1 Tcf under the Base Case. However, every region but MAPP would exceed 1 Tcf under the High Case in 2010 and four regions would exceed 2 Tcf.

## OVERVIEW

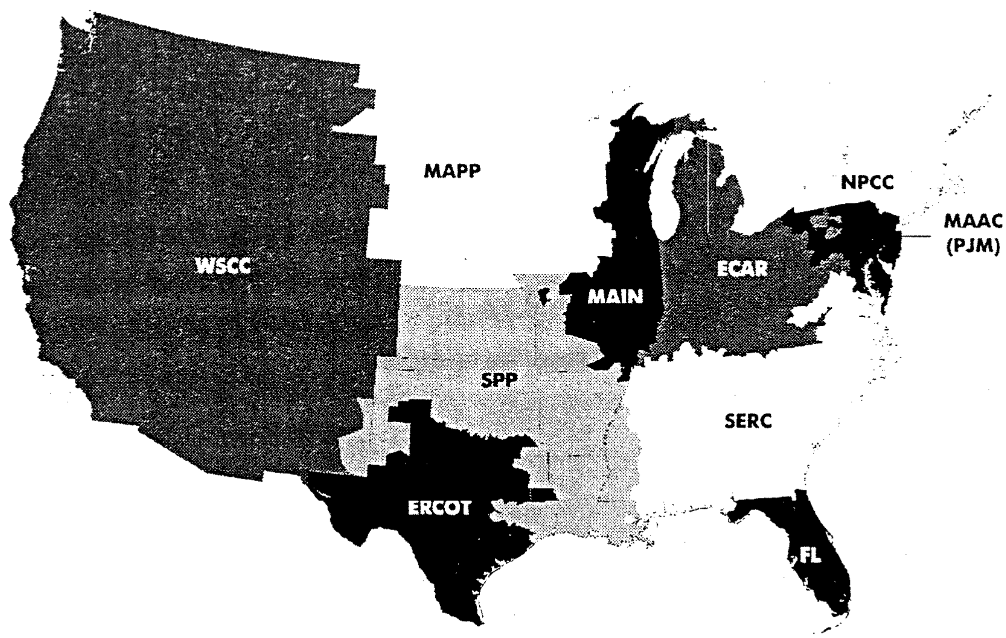
The burden of overhauling the U.S. electricity and gas energy infrastructures would certainly extend across the country, but would be felt more heavily in some regions than in others. **Specifically, RDI finds that the U.S. heartland would be affected to the greatest degree, by virtue of the increase in overall gas demand and the requirements for construction of new generating capacity.** To examine regional impacts, RDI utilizes the electricity regions of the North American Electric Reliability Council (NERC). See Table 3 and Figure 38.

**NERC REGIONS**
TABLE 3

| ABBREVIATION | NAME |
|---|---|
| ECAR | EAST CENTRAL AREA RELIABILITY REGION |
| ERCOT | ELECTRIC RELIABILITY COUNCIL OF TEXAS |
| FRCC | FLORIDA REGIONAL COORDINATING COUNCIL |
| MAAC | MID-ATLANTIC AREA COUNCIL |
| MAIN | MID-AMERICA INTERCONNECTED NETWORK |
| MAPP | MID-CONTINENT AREA POWER POOL |
| NPCC | NORTHEAST POWER COORDINATING COUNCIL |
| SERC | SOUTHEAST ELECTRIC RELIABILITY COUNCIL |
| SPP | SOUTHWEST POWER POOL |
| WSCC | WESTERN SYSTEMS COORDIANTING COUNCIL |

SOURCE: RDI

**MAP OF THE NERC REGIONS**
FIGURE 38




SOURCE: RDI

## COAL CAPACITY AT RISK

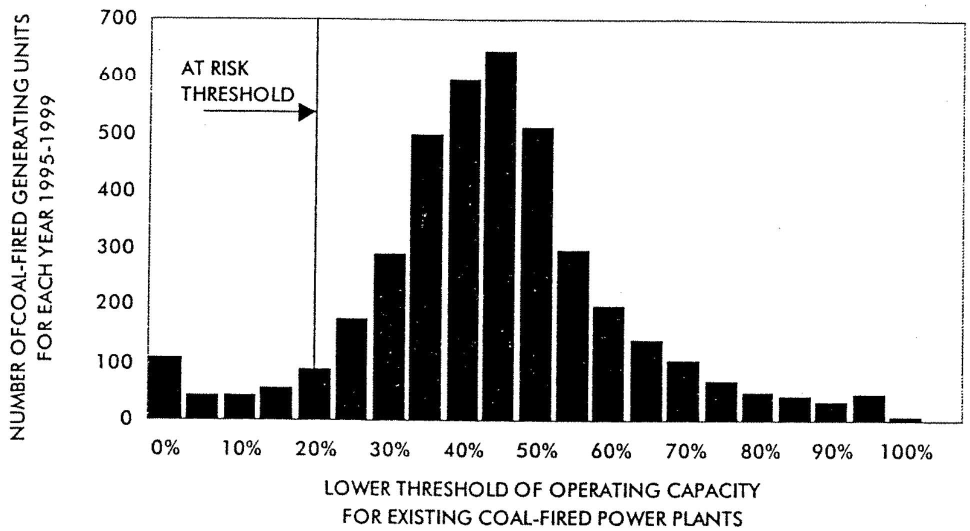
A significant portion of coal capacity would be forced from the generation mix under the Kyoto cases. Some plants would face generation curtailment, others would face retirement or repowering to gas. These are referred to as "at risk" coal plants in this report. RDI has assumed that any coal unit curtailed in our modeling results to a capacity utilization factor of less than 20% on an annual average basis would likely be at risk. This broad assumption, which would obviously vary by unit in reality, is based on analysis of recent coal plant utilization.

RDI analyzed capacity utilization data at all major coal-fired units in the country over the period 1995-1999. In each case, RDI determined the lower threshold for operation by examining hourly generation against capacity, and developed statistics describing annual capacity utilization. The resulting histogram is shown in Figure 39. The lower operating thresholds for existing coal units vary fairly uniformly. A significant number of units will not operate below a 40% utilization factor for operational reasons, but some units can cycle in such a way that annual capacity factors of 25% to 30% are possible. The data clearly indicate that a majority of the operating coal units do not operate at a capacity factor below 20% on an annual basis.

Given a 20% annual utilization threshold, RDI estimates that plants at risk in ECAR and SERC would total between 25,000 and 30,000 MW in the Moderate Case and nearly 50,000 MW in the High Case by 2010. The ECAR and SERC regions currently host 83,000 and 66,000 MW of coal-fired capacity, respectively. See Figure 40. Plants in MAIN, MAAC, SPP, and WSCC form the next group at risk. These regions could potentially lose between 10,000 and 20,000 MW each in the Moderate and High Cases, respectively. Total coal-fired capacity at risk in the U.S. by 2010 would be 130,000 MW in the Moderate Case and 220,000 MW in the High Case. Total coal capacity in the U.S. is about 315,000 MW.

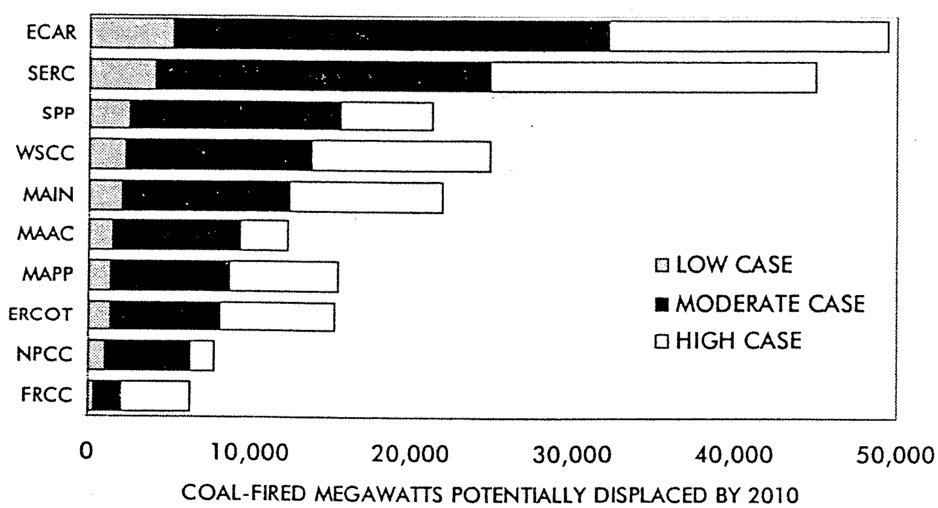
The age of the at-risk units varies, but plants commissioned in the 1950s form the largest at risk group due to generally lower efficiencies. For further perspective, half the number of all currently existing coal units were commissioned by 1962, while half of all coal-fired generating capacity was in place by 1972. By 1979, almost three-quarters of all current existing capacity was on line, as were 87% of all units. See Figure 41.

**LOWER THRESHOLD OF COAL-FIRED CAPACITY UTILIZATION, 1995-1999**
FIGURE 39




SOURCE: RDI

**COAL POWER AT RISK IN 2010 - KYOTO CASES**
FIGURE 40



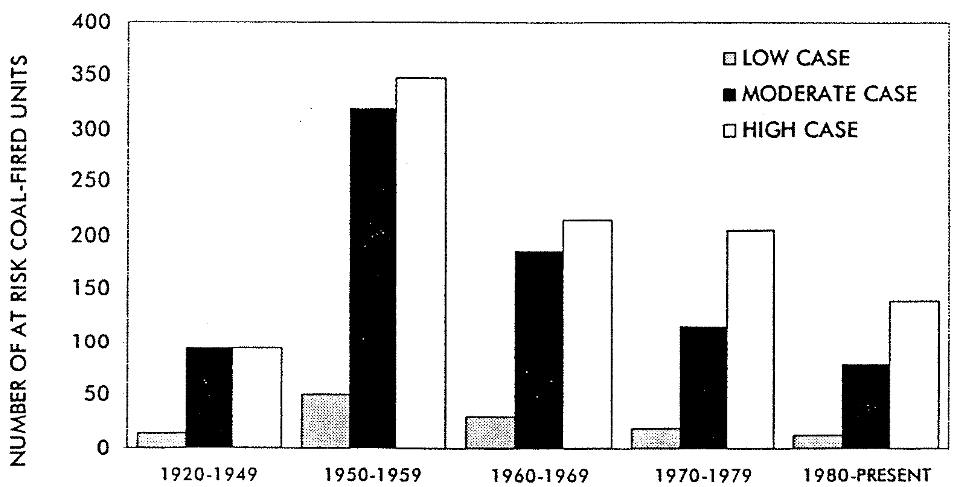

SOURCE: RDI

**COAL POWER AT RISK IN 2010 - KYOTO CASES**
TABLE 4

| NERC | LOW CASE | MODERATE CASE | HIGH CASE |
|---|---|---|---|
| ECAR | 5,156 | 32,127 | 49,396 |
| ERCOT | 1,301 | 8,106 | 15,220 |
| FRCC | 331 | 2,060 | 6,279 |
| MAAC | 1,498 | 9,337 | 12,292 |
| MAIN | 1,983 | 12,355 | 21,942 |
| MAPP | 1,388 | 8,646 | 15,383 |
| NPCC | 1,008 | 6,284 | 7,701 |
| SERC | 3,989 | 24,855 | 44,995 |
| SPP | 2,485 | 15,487 | 21,261 |
| WSCC | 2,198 | 13,693 | 24,784 |
| U.S. TOTAL | 21,336 | 132,950 | 219,253 |

SOURCE: RDI

**VINTAGE OF COAL UNITS AT RISK IN 2010**
FIGURE 41




SOURCE: RDI

## GENERATING CAPACITY ADDITIONS

With up to 90% of U.S. coal capacity potentially curtailed or retired, generation would need to come from other sources, primarily natural gas. To accomplish the switch to gas, generating companies would be required to construct a new fleet of plants. Figure 42 shows projected gas-fired capacity additions by NERC region through 2010. In our Base Case, the greatest amount of construction is expected in SERC, with 34,000 MW of new gas-fired power plants from 1998 and 2010. Of those plants, more than 17,000 MW should be combined cycle.[29] Under the High Case, SERC would add 40,621 MW, of which two-thirds would be combined cycle.

This level of generation expansion would require large-scale increases in pipeline capacity in the Southeast. Although significant capacity does pass through the region, Georgia, Florida, and the Carolinas are limited in their ability to access gas from these lines. In the High Case, ECAR would become the third largest region for new gas-fired capacity by 2010, expanding from 16,925 MW under our Base Case to 29,924 MW under the High Case, or an additional 88%. Also in our Base Case, almost all of the capacity is forecast to consist of simple-cycle combustion turbine technology, which is used for peaking needs. In the Kyoto cases, more than 90% of the new capacity would be combined cycle for baseload. See Figure 43. The WSCC, which covers the West, would also experience a strong construction activity. In our Base Case, over 22,000 MW of gas capacity expansions are forecast by 2010, almost 75% of which is projected to serve California and the Pacific Northwest. These expansions will not lead to pipeline constraints because of the excess capacity that already exists in the region. In the Moderate and High Cases, over 35,000 MW are projected for the region by 2010.

In general, when the costs of carbon emissions are factored into the dispatch price, new combined cycle capacity displaces a significant portion of coal-fired generation. But in regions where coal is inexpensive, carbon costs would be insufficient to displace the lowest-cost coal units. This is especially true in the Low and Moderate Cases. Gas-fired plants would displace the higher-cost, coal-fired plants, but not the lowest-cost coal plants. Some of the added capacity displaces existing gas and oil-fired units and less efficient combined cycles added a few years earlier. **Therefore, while significant amounts of coal generation would be idled, new gas plants would not be completely effective in reducing carbon emissions to meet Kyoto Protocol targets.**

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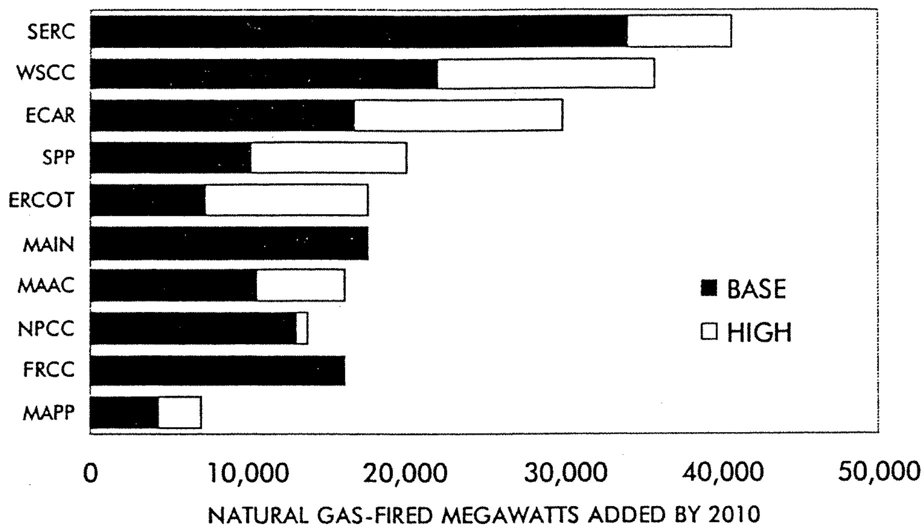
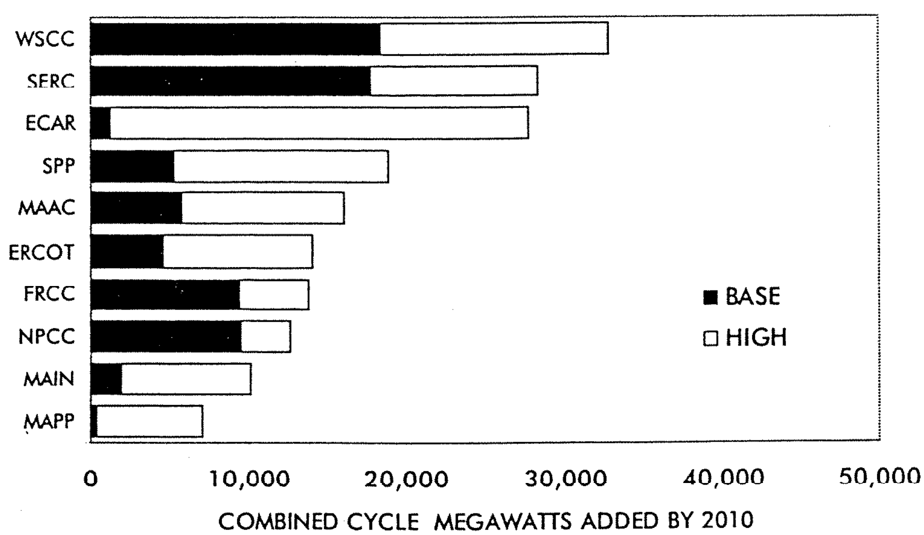
[29] Combined-cycle generating units are the advanced turbine designs with heat-recovery systems. These power plants are very fuel efficient, and typically operate as baseload units.

**NEW GAS-FIRED, 2010 - BASE CASE AND HIGH CASE**
FIGURE 42




SOURCE: RDI

**NEW GAS-FIRED COMBINED CYCLE POWER PLANTS, 2010 - BASE CASE AND HIGH CASE**
FIGURE 43




SOURCE. RDI

## ELECTRIC GENERATION GAS DEMAND BY REGION

The increases in gas-fired generation are projected to create large differences in regional gas demand for electric generation. This can be seen from Table 5, in which one electric market, ERCOT, consumed over 1 Tcf during 1998. In the Base Case forecast, three markets consume at least 1 Tcf by 2010. In contrast, every market but MAPP would exceed 1 Tcf of annual consumption under the High Case by 2010, and four markets would exceed 2 Tcf per year. In the Low Case, interregional shifts in generation flow can lower gas demand in particular regions. In some cases it becomes cheaper to move power than to generate locally, changing the demand for gas in the region. This shifting occurs in SERC and MAIN, which receive power from SPP and ECAR, respectively.

**ELECTRICITY SECTOR GAS DEMAND BY NERC REGION**
TABLE 5. BILLIONS OF CUBIC FEET

**2010 ELECTRIC GENERATION GAS DEMAND (BCF)**

| NERC | 1998 | BASE | LOW | MOD. | HIGH |
|---|---|---|---|---|---|
| ECAR | 68 | 218 | 1,046 | 1,519 | 2,001 |
| ERCOT | 1,018 | 1,387 | 1,326 | 1,652 | 2,007 |
| FRCC | 346 | 654 | 1,099 | 1,050 | 1,248 |
| MAAC | 223 | 505 | 966 | 924 | 1,065 |
| MAIN | 59 | 267 | 241 | 674 | 1,314 |
| MAPP | 9 | 97 | 110 | 359 | 491 |
| NPCC | 416 | 837 | 1,277 | 1,197 | 1,107 |
| SERC | 145 | 1,027 | 929 | 2,013 | 2,518 |
| SPP | 484 | 686 | 1,341 | 1,469 | 1,849 |
| WSCC | 937 | 1,749 | 2,048 | 2,338 | 2,616 |
| USA | 3,705 | 7,427 | 10,383 | 13,196 | 16,216 |

**2010 % ABOVE THE BASE CASE**

| NERC | LOW | MOD. | HIGH |
|---|---|---|---|
| ECAR | 379% | 596% | 816% |
| ERCOT | -4% | 19% | 45% |
| FRCC | 68% | 61% | 91% |
| MAAC | 92% | 83% | 111% |
| MAIN | -10% | 153% | 393% |
| MAPP | 13% | 269% | 405% |
| NPCC | 53% | 43% | 32% |
| SERC | -10% | 96% | 145% |
| SPP | 95% | 114% | 170% |
| WSCC | 17% | 34% | 50% |
| USA | 40% | 78% | 118% |

SOURCE: RDI

## TOTAL GAS DEMAND BY REGION

RDI projects that by 2010, the largest gas consuming regions under our Base Case will be WSCC, ERCOT, SERC and NPCC, in that order. These regions will together account for 59%, or 16.3 Tcf, of the 28 Tcf of total U.S. gas demand.[30] Under the Kyoto cases, substantial increases in ECAR and SERC gas demand are evident by 2010. In the High Case, the top four regions would still account for 57% of total U.S. demand, or 19.2 Tcf. See Table 6.

**TOTAL GAS DEMAND BY NERC REGION**
TABLE 6. BILLIONS OF CUBIC FEET

| | | 2010 TOTAL GAS DEMAND (BCF) | | | |
|---|---|---|---|---|---|
| NERC | 1998 | BASE | LOW | MOD. | HIGH |
| ECAR | 2,920 | 3,277 | 4,158 | 4,380 | 4,674 |
| ERCOT | 3,693 | 4,108 | 3,968 | 4,131 | 4,451 |
| FRCC | 541 | 864 | 1,318 | 1,254 | 1,446 |
| MAAC | 1,600 | 1,900 | 2,366 | 2,198 | 2,224 |
| MAIN | 1,705 | 2,075 | 2,053 | 2,316 | 2,821 |
| MAPP | 854 | 1,058 | 1,073 | 1,234 | 1,293 |
| NPCC | 1,856 | 2,301 | 2,342 | 2,546 | 2,754 |
| SERC | 1,789 | 2,927 | 2,887 | 3,815 | 4,216 |
| SPP | 3,370 | 3,817 | 4,372 | 4,310 | 4,614 |
| WSCC | 3,722 | 5,058 | 5,322 | 5,357 | 5,434 |
| USA | 22,050 | 27,384 | 29,859 | 31,541 | 33,926 |

| | 2010 % ABOVE THE BASE CASE | | |
|---|---|---|---|
| NERC | LOW | MOD. | HIGH |
| ECAR | 27% | 34% | 43% |
| ERCOT | -3% | 1% | 8% |
| FRCC | 53% | 45% | 67% |
| MAAC | 25% | 16% | 17% |
| MAIN | -1% | 12% | 36% |
| MAPP | 1% | 17% | 22% |
| NPCC | 2% | 11% | 20% |
| SERC | -1% | 30% | 44% |
| SPP | 15% | 13% | 21% |
| WSCC | 5% | 6% | 7% |
| USA | 9% | 15% | 24% |

SOURCE: RDI

[30] The totals presented in Table 4 do not include pipeline fuel consumption, and therefore are slightly lower than the demand figure presented in Figure 3.

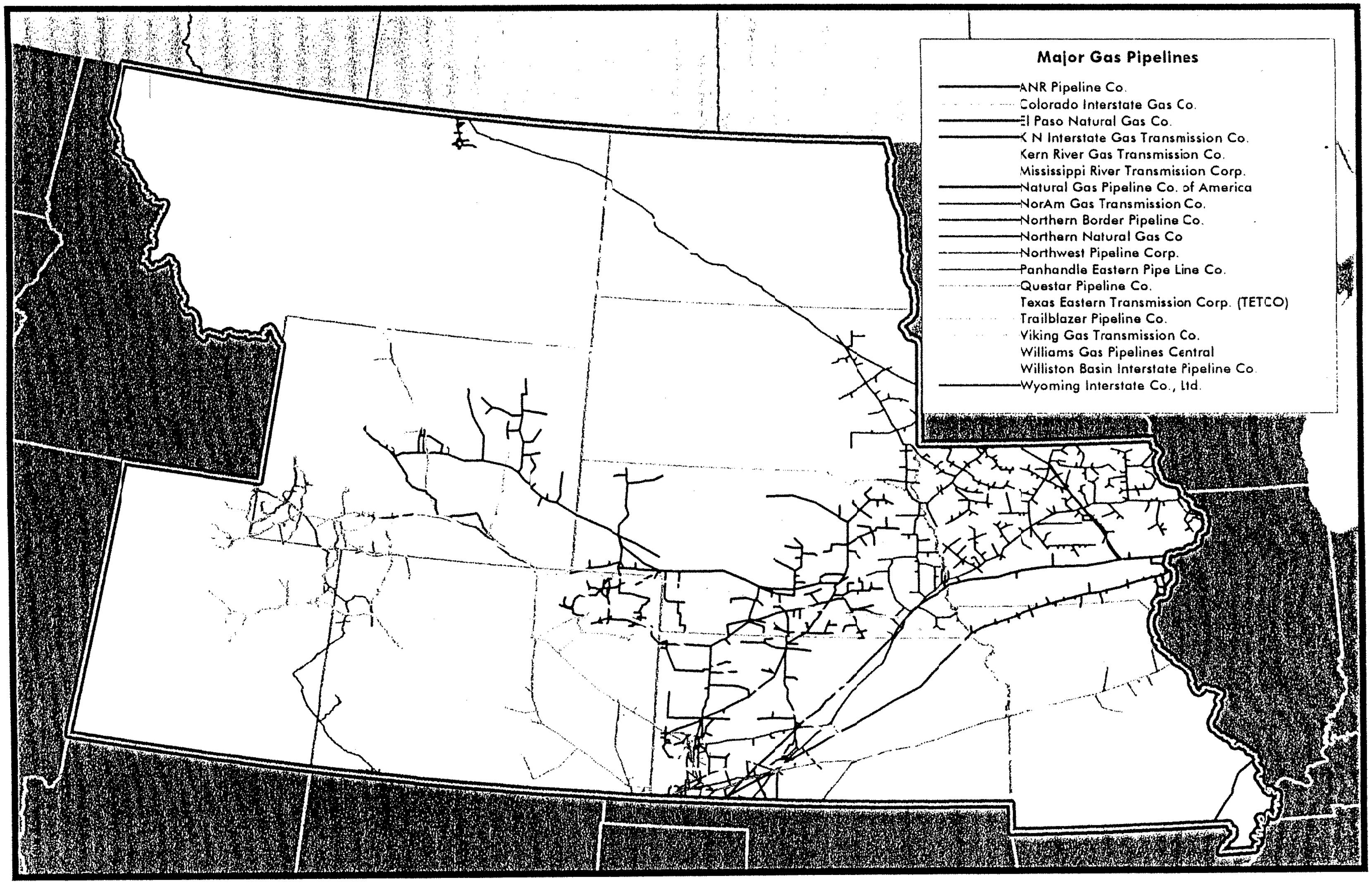
As is clear from this analysis, electric sector gas demand is poised to grow by 5 Tcf per year of annual consumption by 2010 under Base Case conditions. Total demand of 27 Tcf in 2010 far exceeds any historic precedent. Against this backdrop, the Kyoto Protocol would require additional growth to reach 30 to 34 Tcf under the Low and High Cases, or increases of 8 to 12 Tcf above current consumption levels.

# Appendix

**APPENDIX TABLE OF CONTENTS**

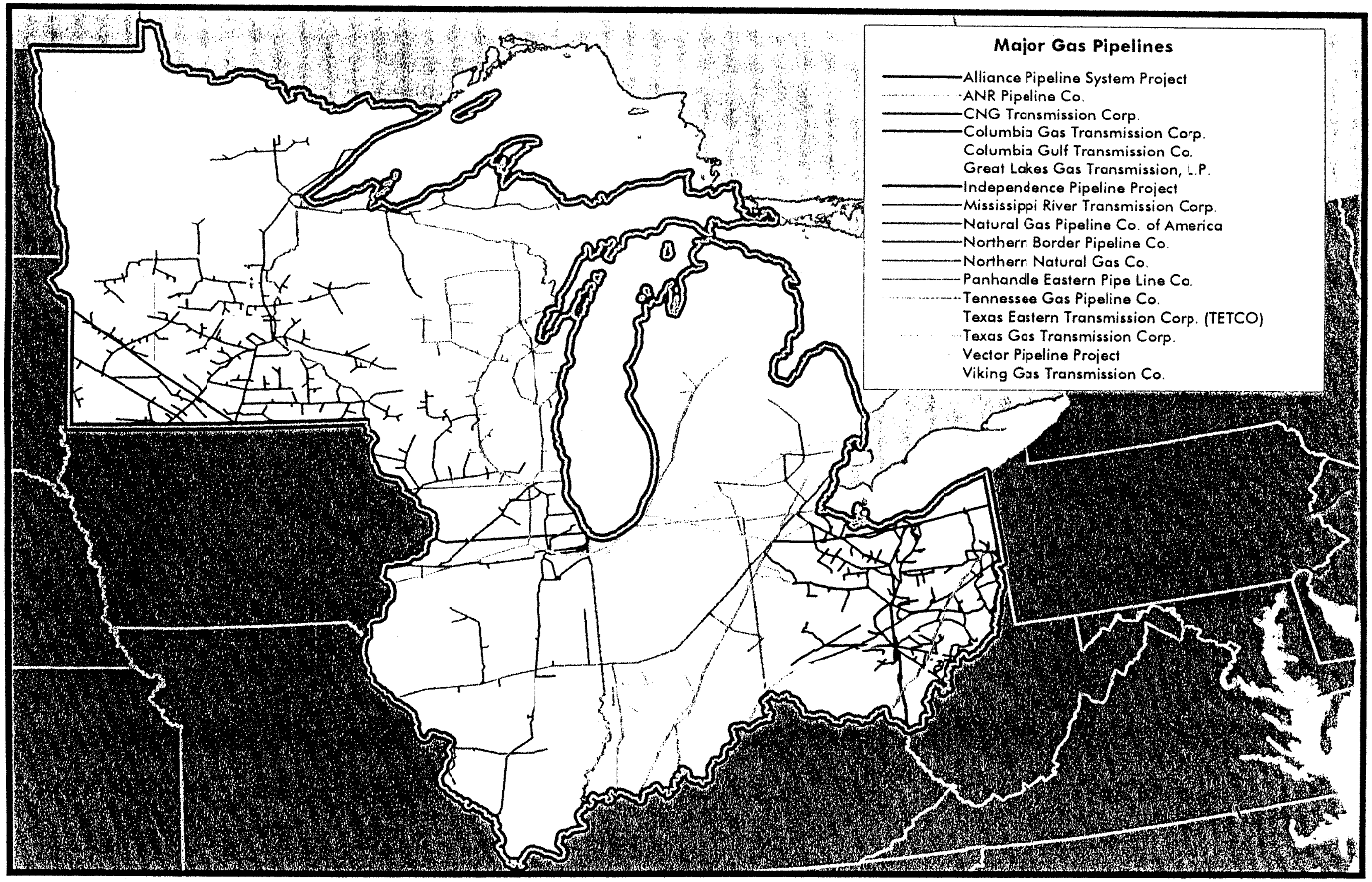
## MAJOR NATURAL GAS PIPELINES - CENTRAL REGION

GAS REGION MAP 1



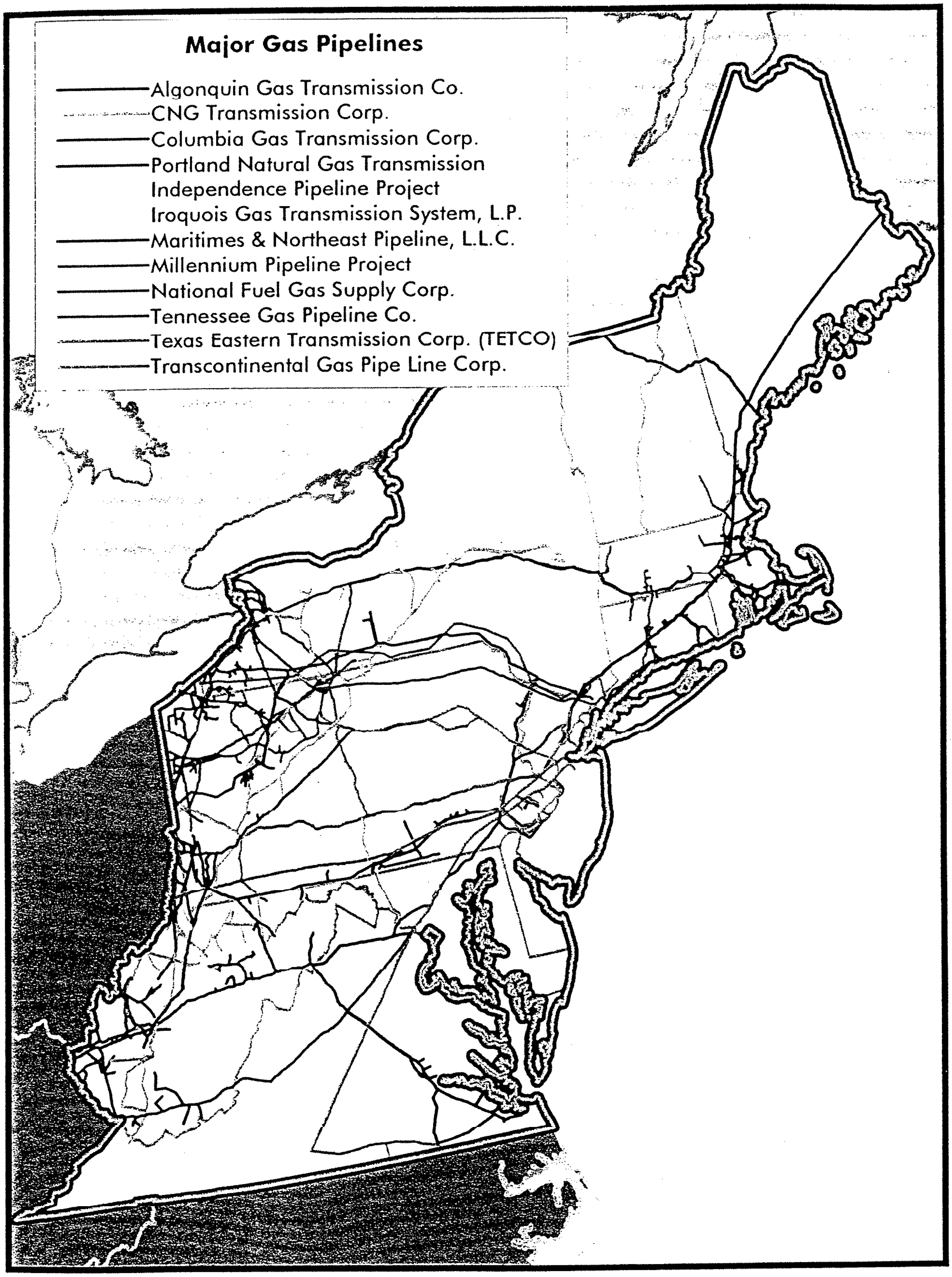
**MAJOR NATURAL GAS PIPELINES - MIDWEST REGION**

GAS REGION MAP 2



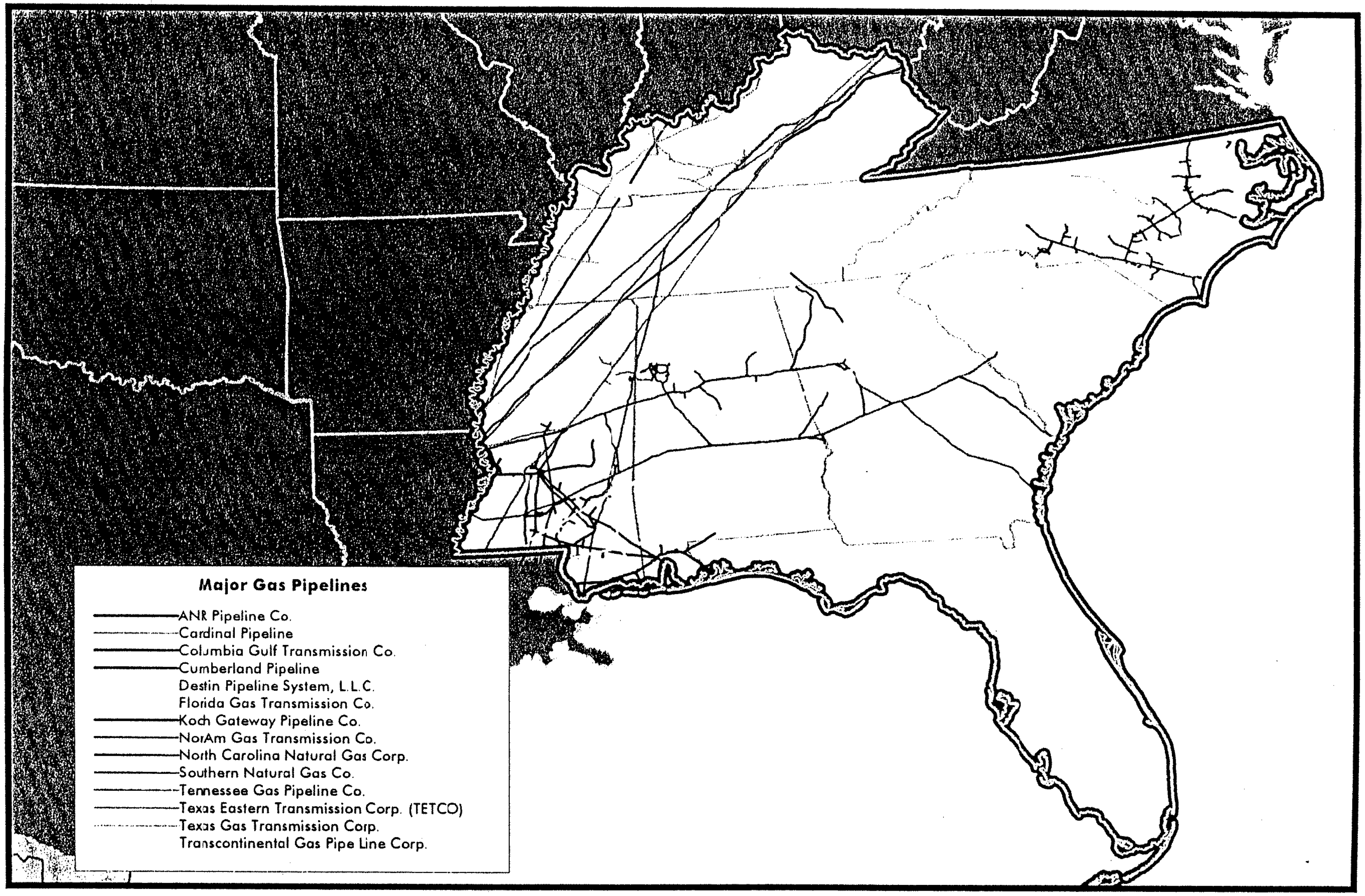
**MAJOR NATURAL GAS PIPELINES - NORTHEAST REGION**

GAS REGION MAP 3



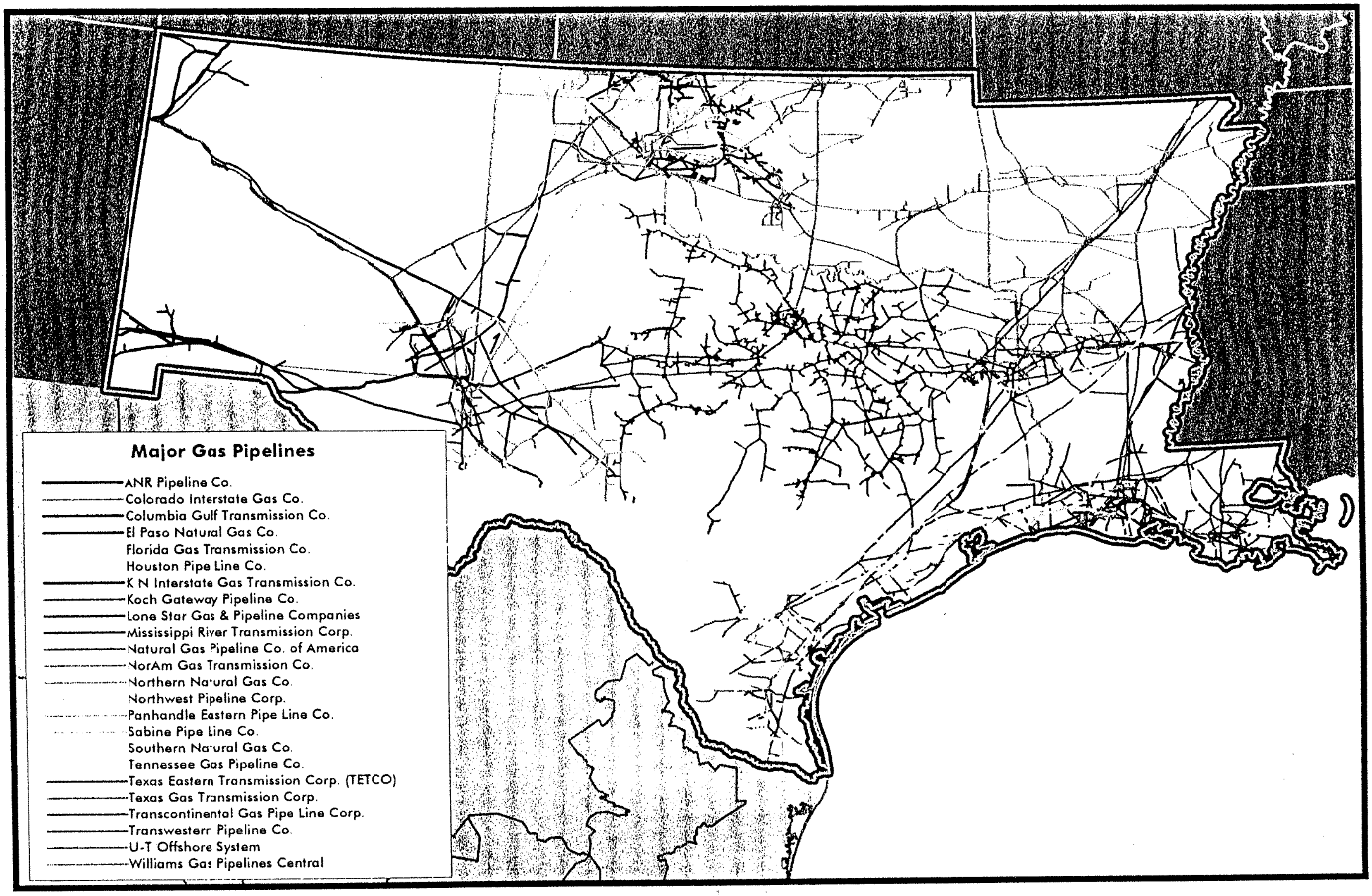
## MAJOR NATURAL GAS PIPELINES - SOUTHEAST REGION

GAS REGION MAP 4



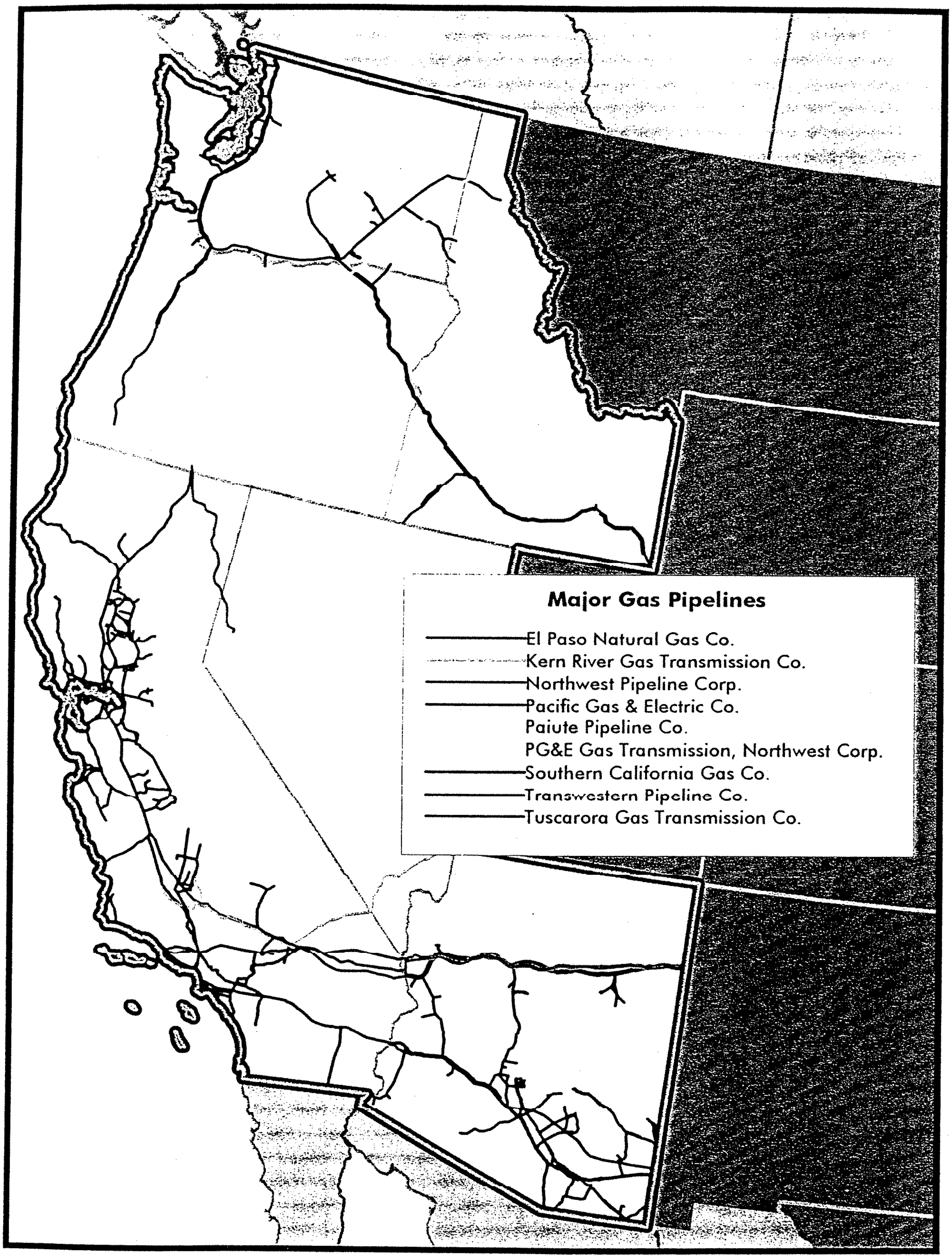
## MAJOR NATURAL GAS PIPELINES - SOUTHWEST REGION

GAS REGION MAP 5



**MAJOR NATURAL GAS PIPELINES - WESTERN REGION**

GAS REGION MAP 6



Attachment 2

Ameren Energy Generating Company
Subpart W NOx Control Strategy Compliance Cost Estimates

| Plant | Technology | Estimated Installed Cost ($ in millions) | Cost Source |
|---|---|---|---|
| | | | |
| Coffeen | (2) Selective Catalytic Reduction (SCR) Units | $110.8 | Vendor proposal and engineering design estimate |
| | | | |
| Hutsonville | (2) over-fire air (OFA) retrofits | $3.9 | Vendor supplied budgetary estimate |
| | | | |
| Meredosia | Tangential Firing System (TFS) 2000 (low NOx burner retrofit) | $10.3 | Vendor supplied budgetary estimate |
| | | | |
| Newton | Tangential Firing System (TFS) 2000 (low NOx burner retrofit) | $11.9 | Vendor proposal |
| | | | |
| Total | | $136.9 | |

Note: Installed cost includes capital to construct but does not include operation and maintenance costs.

ATTACHMENT 2

## CERTIFICATE OF SERVICE

The undersigned hereby certifies that copies of the foregoing **AMEREN CORPORATION'S POST HEARING COMMENTS** were served on behalf of Ameren Corporation upon:

See: Attached Service List

on or before 5:00 p.m. on this 13$^{TH}$ day of October, 2000, by first class U.S. mail, postage prepaid.

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