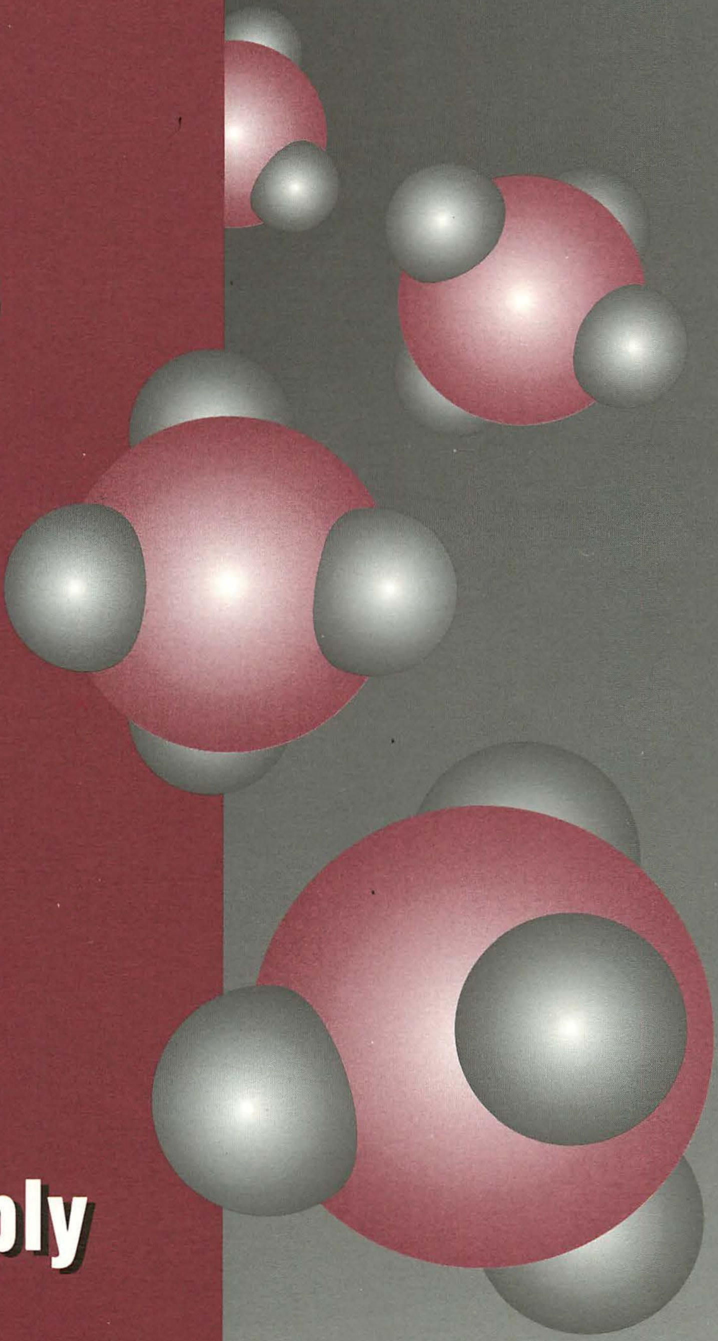
The Potential for Natural Gas in the United States

Source and Supply



December 1992
National Petroleum Council

On the Cover: Graphic Representation of Methane Molecules, CH_4, the Primary Chemical Compound in Natural Gas.

NATIONAL PETROLEUM COUNCIL
1625 K Street, N.W., Washington, D.C. 20006 (202) 393-6100

December 17, 1992

The Honorable
James D. Watkins
Secretary of Energy
Washington, D.C. 20585

Dear Mr. Secretary:

On behalf of the members of the National Petroleum Council, I am pleased to transmit to you herewith the Council's report entitled *The Potential for Natural Gas in the United States*. This report was prepared in response to your request and was unanimously approved by the membership at their meeting today.

Natural gas has the potential to make a significantly larger contribution both to this nation's energy supply and its environmental goals. Achieving that potential will take a commitment of innovation, leadership, and resources by the industry to overcome challenges that arise from its current operations, its history, and its regulation. The National Petroleum Council concludes that industry has already initiated actions in support of that commitment and believes the industry is prepared to continue those activities.

This study finds that natural gas is uniquely positioned to take on this expanded role for three reasons:

1. Natural gas can be produced and delivered in volumes sufficient to meet expanding market needs at competitive prices.
2. Natural gas is a clean-burning fuel, and can be used in a variety of applications to satisfy environmental requirements.
3. Natural gas is a secure, primarily domestic source of energy that can help improve the national balance of foreign trade.

In addition, much of the groundwork necessary to develop a more competitive and customer-oriented industry has already been laid.

Perceptions of natural gas that arise from its heavily regulated past represent the greatest challenge to be overcome by the industry. In particular, the industry must pay more attention to meeting customer needs through greater efficiency and more competitive services. Efforts like this study to define the problem and outline its solution, have become critical to realization of natural gas' potential.

The National Petroleum Council sincerely hopes the enclosed report will be of value to the Department of Energy, and government at all levels, as natural gas and the natural gas industry realize their potential.

Respectfully submitted,

Ray L Hunt

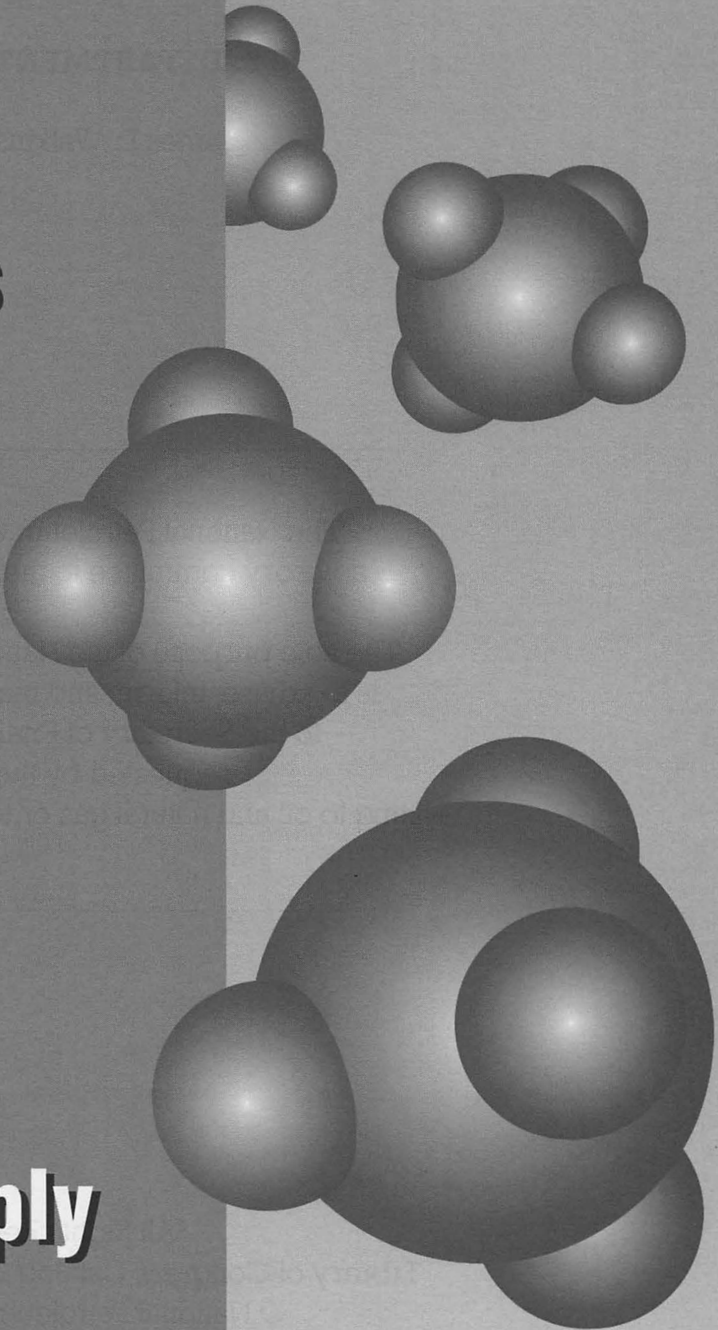
Ray L. Hunt
Chairman

Enclosure

An Advisory Committee to the Secretary of Energy

The Potential for Natural Gas in the United States

Source and Supply



December 1992
National Petroleum Council

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The National Petroleum Council is a federal advisory committee to the Secretary of Energy.

The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to oil and natural gas or to the oil and gas industries.

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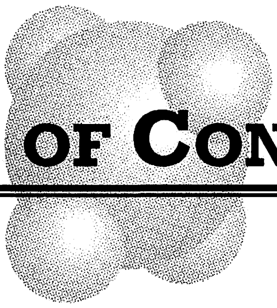

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SUMMARY

OVERVIEW

This study by the National Petroleum Council, and particularly its assessment of the resource base and its availability, finds abundant domestic resources in place, an advancing level of technology making those resources available, and additional volumes available through trade within North America and elsewhere. The opportunity to make natural gas a secure and more widely utilized fuel available at moderate prices is substantial. To take advantage of this opportunity, however, will require a vital natural gas industry operating in a market-driven environment with full public recognition of the costs and benefits of environmental regulation, continuing technology emphasis, and access to resources for exploration and development. The Council firmly believes this can be accomplished to the mutual benefit of the nation and all involved in natural gas production, transportation, marketing, and consumption.

Additionally, the industry must learn from past mistakes and build on demonstrated performance. Past fears of limited reserves brought on in part by the industry's lack of foresight must be addressed and corrected. Steps toward deregulation have only recently progressed to the point that the industry can demonstrate its potential to respond in a competitive market. Concerns that arise during transition to a fully market-driven structure must be acknowledged and overcome.

Invariably, the fortunes of natural gas have been impacted by those of oil, whose swings during the last two decades have been unprecedented. Even though gas and oil markets now function independently, the persistence of an excess of gas supply (the so-called "gas bubble") and a maturity of domestic oil reserve opportunity are contributing together to a scale-back of North American producer activity. Despite the economic basis for such change, there is concern in the market as to potential implications for future gas supply reliability. Price volatility, as seen in the form of monthly wellhead spot price changes, adds to the concern. Although sharp swings, such as those seen in 1992, may be largely the temporary product of transition to a competitive market, all participants are looking for ways to minimize individual exposure.

Within this setting, and at the explicit request of the Secretary of Energy (See Appendix A), the Source and Supply analysis of this study was conducted under the following mission statement:

- ***Evaluate supply aspects of the potential for natural gas to make a greater contribution to the nation's energy balance.*** A credible estimate is required of the recoverable resource base and economic long-term supply including conventional, nonconventional, and import alternatives. Uncertainties of a geologic, technical, and regulatory nature must be recognized. Historical perspective and vision for the future are required to identify industry and government initiatives to reduce barriers, provide confidence in supply, and enhance future natural gas availability.

KEY SOURCE AND SUPPLY FINDINGS

During the course of this study, the supply potential for the U.S. market has been examined and recommendations have been made supporting improved supply utilization. Through in-depth technical assessment of the resource and delivery potential, use of a sophisticated modeling tool and specific focus on key parameters including technology, environmental regulation, and contracting practices, the NPC has arrived at the following findings:

- The United States has a vast and diverse recoverable natural gas resource base that will continue to grow with time and technology. Anticipating such growth through 2010, the NPC estimates the technically recoverable resource at 1,295 trillion cubic feet (TCF) for the lower-48 states alone. Potential Canadian, Mexican, Alaskan, and liquefied natural gas (LNG) supply are also backed by large resources. Contrary to past perceptions, the natural gas resource base itself is not (and should not be viewed as) a limit to expanded gas usage. Industry must take the lead in ensuring that this message is articulated and adopted in the market. The Department of Energy (DOE) is urged to join in promoting this assessment. It should be used as the basis for future federal and state policy determination.

- Natural gas supply from these resources can be made competitively available to meet foreseeable demand growth if proper market signals, technology advancement, and environmental management practices are forthcoming. For example, under Reference Case 1 (the moderate energy growth scenario), market driven, competitive pricing for natural gas can bring forth sufficient supply to sustain current uses and attract new customers. Case 1 shows that a 25 percent increase in demand to 25 quadrillion British thermal units (QBTU) by 2010 is supportable.

- Model results indicate that supply is not likely to be sustainable for the long term at wellhead gas prices typical of recent years. However, they do indicate that supply can be sustained, and even increased, at prices that nevertheless remain competitive with expected user alternatives. Case 1 indicates that a Texas Gulf Spot gas price growing to $3.50 (1990$) per million BTU (MMBTU) by 2010 would stimulate sufficient supply to competitively meet a growing energy demand in a growing oil price environment (assumed oil price $28 per barrel in 2010). Reference Case 2 (the low energy growth scenario) indicates that a $2.50 price by 2010 would stimulate sufficient supply to sustain today's gas market share of limited energy growth outlook (assuming a constant oil price environment). Evaluation of supply potential beyond 2010 indicates that continuing technology gain can help minimize costs and perpetuate supply until 2020 at $2.50, and 2030 at $3.50.

- Annual oil and gas expenditures for the producing industry have averaged $35 to $40 billion (1990$) over the past few years. This is comparable to the level of expenditure in the mid-1970s and about half of the peak expenditure years in the early 1980s. For Reference Case 1, where domestic production increases to over 20 TCF by the year 2010, investment levels are projected to increase gradually over the next 10 years and average about $60 billion (1990$) annually during the 2000-2010 time period. Lesser increases are expected for Reference Case 2, which projects annual investments remaining below $50 billion (1990$) throughout the study period.

- A long history of intense and changing regulation, accentuated by public and private underestimates of supply potential, has worked to suppress demand and perpetuate the prevailing oversupply situation. The current contraction of producer activity is, in part, the delayed result of these forces rather than lack of drilling opportunity. Therefore, this trend is reversible if market signals so dictate. However, there may be some lag and some continued price volatility due to the lead time inherent in many investment decisions in all phases of the business.

- Contract diversity, driven by a customer-oriented attitude and supported by a regulatory climate that honors contract sanctity, can work to stabilize the market environment, encourage new supply, support demand growth, and ensure that the each participant attains the degree of reliability, security, and other services it desires. Risk management tools are also available to support all participants in managing exposure to competitive market uncertainty. Over time, such diversity and practices can work to better transmit market signals and reduce general price volatility.

- Technology advancement has proven to be a key factor in the historical growth of gas supply. Continued advancement of technology at similar rates is necessary to ensure that natural gas resources can be developed in a timely, cost-efficient manner. Private technology initiative must continue to play the lead role. An NPC survey of representative producer and service company research and development (R&D) spending indicates that technology effort remains strong despite reduced profits, declining drilling activity, and ongoing restructuring programs. Nevertheless, greater emphasis on cooperative programs is urged to ensure stability of technology effort, optimum performance, and effective technology transfer throughout industry. Federal funding, based on recognition that public interest would be served by a sustained, stable gas supply, is an appropriate supplement for programs that are not otherwise driven by proprietary advantage. Federal research funding for natural gas has been historically low relative to spending related to other fuels and should be reviewed in recognition of greater gas supply potential than previously assumed. Aspects that help reduce supply costs, including means to enhance environmental cost efficiency, merit greater consideration.

- The availability of natural gas, and the corresponding merits of its increased use as a clean fuel, are at risk from environmental restrictions on the supply side that limit access and raise costs without adequate balance of costs and benefits. A significant portion of the resource base is currently inaccessible due to leasing moratoria on the Outer Continental Shelf (OCS); is restricted in wilderness areas, marine sanctuaries, National Parks, and Fish and Wildlife Service lands; and is subject to other *de facto* administrative moratoria. The full potential of these areas will not be known until access is granted. Modeling results indicate that too stringent application of clean air, clean water, safe drinking water, hazardous waste, and other environmental laws without adequate regard to costs and benefits, including recognition of the downstream environmental benefits of natural gas, could potentially raise environmental compliance costs by $30 billion or more and reduce domestic supply 10 percent by 2010.

- The legislative and regulatory process should be reexamined and modified to bring more balance into the decision-making process. Industry must recognize and work to correct negative perceptions. It should develop innovative strategies to align its goals and preplan its projects to better recognize the public's environmental expectations. Industry and government need to enhance education programs and work to ensure that factual information is available and communicated to help bring a better balance to environmental decision making.

SUPPLY VISION

The natural gas business is inherently a long lead time industry supported by complex technologies and investments in all operational phases. Time will be required to implement the changes in perception and practice proposed in this study. Anticipating such change will occur, the Source and Supply Task Group believes the following to be an appropriate vision:

- Natural gas is an abundant, reliable, environmentally attractive source of energy that can meet foreseeable demand growth at competitive prices for the end user. Industry, environmental, and government organizations will work together to recognize the full merits of natural gas, resulting in future environmental regulation and access which balance costs and benefits.

- Continuing technology advancement will help keep supply costs at competitive levels, enhance the timely replacement of reserves, and add new resources to those previously defined. Supply technology advancement will be led by private, competitively driven R&D supplemented with cooperative programs and greater government support.
- Market forces and contract relationships will bring mutually beneficial cooperation between buyer, seller, and transporter. Contracts for short and long-term alike will be respected through the proper exercise of federal and state oversight.
- Government fiscal policy will support a healthy natural gas business and timely capital investments. Natural gas will trade freely within and across state and national boundaries, thus strengthening supply security through diversity and opening additional markets to domestic supplies.

This vision stems from in-depth evaluation by the Source and Supply Task Group and its subgroups of the resource base, supply potential and constraint/opportunity areas as summarized in this overview and described in more depth in subsequent chapters of this Source and Supply volume.

ACKNOWLEDGMENTS

The NPC Source and Supply Task Group was fortunate in having the support of numerous corporate, government, trade, and academic organizations in providing staff support and expertise. Over 100 individuals participated directly on the task group and subgroup committees. These participants were further supported through access to the full resources of the over thirty organizations they represented. Five key work groups organized at the start of this undertaking (namely, Conventional Gas, Nonconventional Gas, Imports & Alaskan Gas, Technology, and Environmental) involved especially extensive commitment of time, talent and effort. Additional subgroups addressed more topic specific aspects such as new field discovery, reserve appreciation, tight sands, Canadian gas, contract diversity, tax policy, and public/consumer education. References to the Source and Supply Task Group refer to the work of these subgroups as well. A full roster of participants is included in Appendix B.

The Source and Supply Task Group wishes to express gratitude to several consultants for their energetic and cooperative support work. Special credit goes to Energy and Environmental Analysis, Inc. (EEA) for modifying and applying the Hydrocarbon Supply Model to address NPC issues and needs. The original commissioning and development of this model date back nearly a decade. It is largely the product of the joint effort of the Gas Research Institute and EEA. ICF Resources, Inc. provided extensive support for tight sands, technology and environmental work. Decision Focus, Inc. provided support of import evaluation through use of its North American Regional Gas Model.

It should be recognized that the broad nature of this study and the intensive analysis done by numerous formal and informal work groups preclude detailed review and agreement to all conclusions by all participants. A consensus-building approach was taken throughout the study process. Nevertheless, the value of fully reporting the effort, and even internally controversial implications, is judged to be greater than restricting the documentation.

RESOURCE BASE

Lower-48 Resource Base

Historical Perspective

For many years, it was popular practice to view the U.S. supply base by looking primarily at proved reserves. In large part, this attitude grew directly out of the pipeline certification process of the Federal Power Commission. To obtain a certificate, a showing of market demand and gas supply was required. The supply requirements typically involved the identification of proved reserves to be dedicated to the project for the lifetime of the facility. Institutions providing capital relied on these dedicated reserves and the certificates for the viability of the proposed project. This process, in conjunction with low gas prices, helped support a rapid expansion of demand but provided little incentive for adding new proved reserves as the formerly vast reserve base reached its peak. By the late 1960s, proved reserves were declining. As can be seen in Figure 1, through most of the 1970s the proved reserve base progressively declined as controlled prices remained well below replacement needs. By the mid-1970s the ratio of proved reserves to annual production had dropped to ten years from a peak of 38 years in 1946. Even though the drop was largely a logical correction to a more economically sustainable level, there was fear it would keep dropping.

This has not turned out to be the case. In fact, the 10 year reserves-to-production ratio for the lower-48 states has remained at about that level for the last 15 years. As can be seen in Figure 2, reserves have remained relatively constant even though substantial additional gas has been produced in the meantime. Obviously, there is additional resource potential to replace the proved reserves as they are used. In simple terms, proved reserves represent and should be perceived as an *inventory* rather than an ultimate capability. Producers will invest in exploration and development to add to proved reserves as there is need and incentive.

The NPC Resource Base Estimate

It is critical to change the focus from proved reserves to recoverable resources. Much work has been done and published in this regard by various organizations and institutions in the past. Accordingly, several NPC Source and Supply subgroups were formed to draw from this expertise as well as to undertake further original work as deemed necessary. Special focus was given to reserve appreciation, tight sands, and technology advancement. The NPC natural gas resource estimate of 1,295 TCF is the result of that extensive effort. It represents current proved reserves plus assessed technically recoverable resources under technology projected to be applicable by 2010.

This estimate, shown by resource category in Table 1, constitutes the consensus opinion. Recognizing that neither today's gas price nor today's technology should limit projection of the supply base available to meet future needs, no explicit economic or price assumptions were set as criteria; however, subjective judgment was used to exclude poorly defined and diffuse portions of the in-place resource potential and to establish reasonable technology trends and recovery factors for the remaining areas. For example, poorly defined nonconventional potential and exotic possibilities such as hydrates were excluded. Recovery factors for both conventional and nonconventional gas were established, anticipating technology advancement over the next 20 years consistent with past experience. The conceptual interrelationship between reserves, resources, economics, and technology is shown graphically in Figure 3.

TABLE 1

NATURAL GAS RESOURCE BASE FOR THE LOWER-48 STATES (Trillion Cubic Feet)

Proved Reserves	**160**
Conventional Resources	
Reserve Appreciation	203
New Fields	413
Subtotal	**616**
Nonconventional Resources	
Coalbed Methane	98
Shales	57
Tight Sands	349
Other	15
Subtotal	**519**
Total Resources	**1,295***

***Technically recoverable resource base as of January 1, 1991, assuming that current access moratoria expire as scheduled and incorporating technology advancement through 2010. Assuming various price levels, with current and advanced technology, yields the following total resource estimates:**

	Recoverable Resource Base (TCF)	
Price (1990$)	**1990 Technology**	**2010 Technology**
Unspecified	**1,065**	**1,295**
$3.50/MMBTU	**600**	**825**
$2.50/MMBTU	**400**	**600**

It was judged appropriate to primarily characterize the resource base under the assumption of 2010 technology to best recognize that technology is a continuing process and

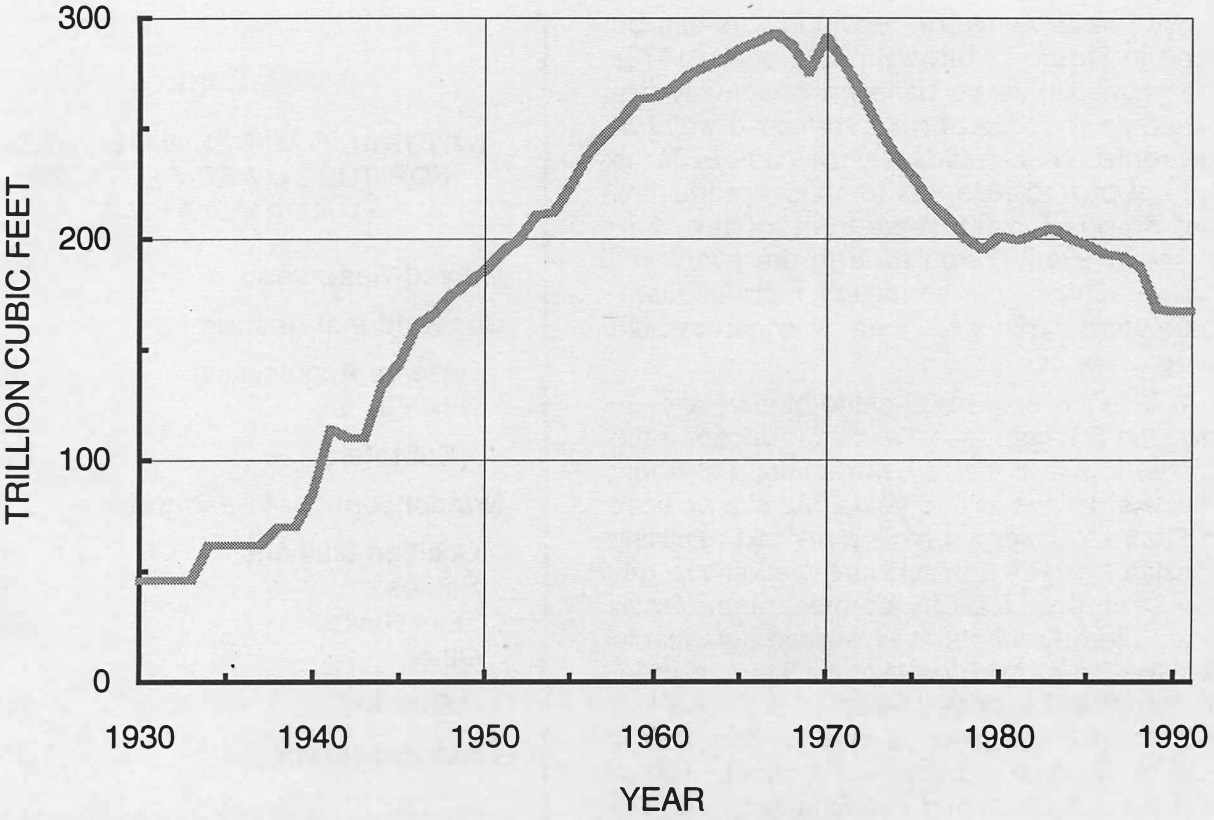


Figure 1. U.S. Natural Gas Proved Reserves.

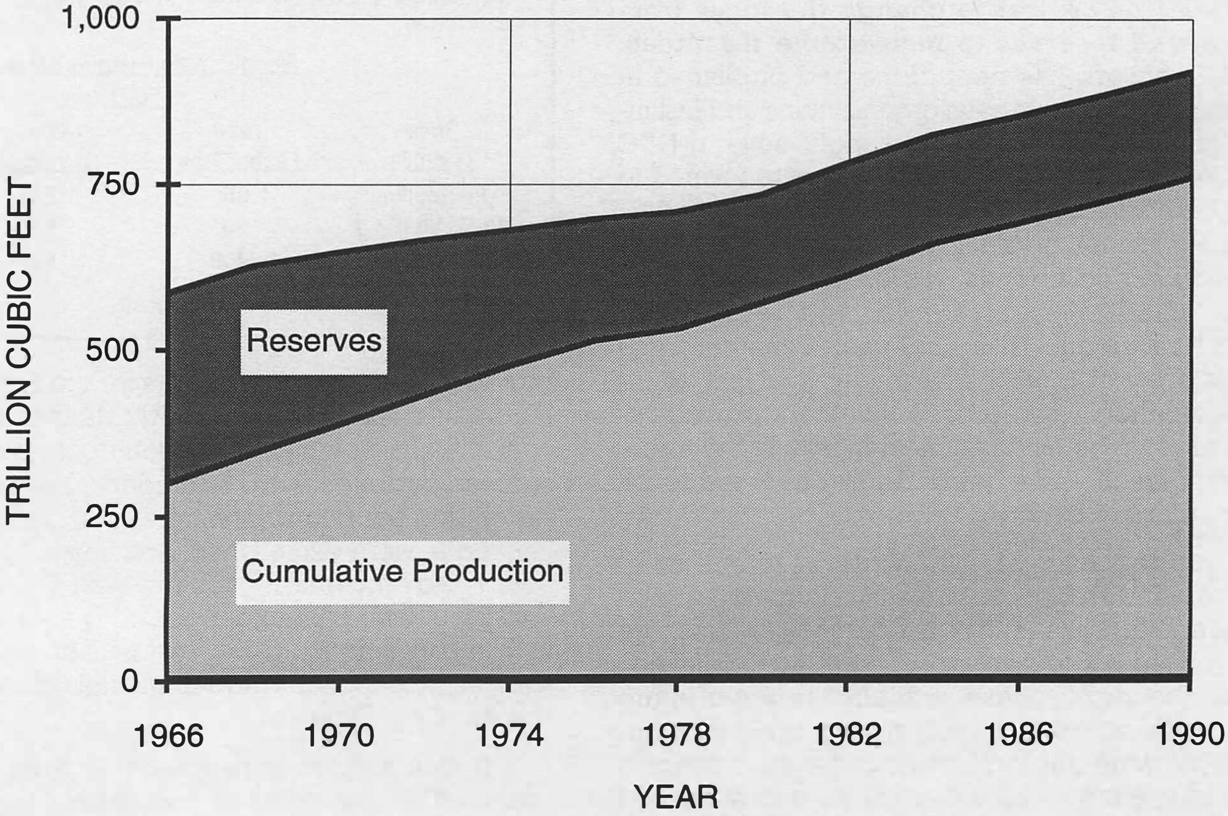


Figure 2. U.S. Reserve History.

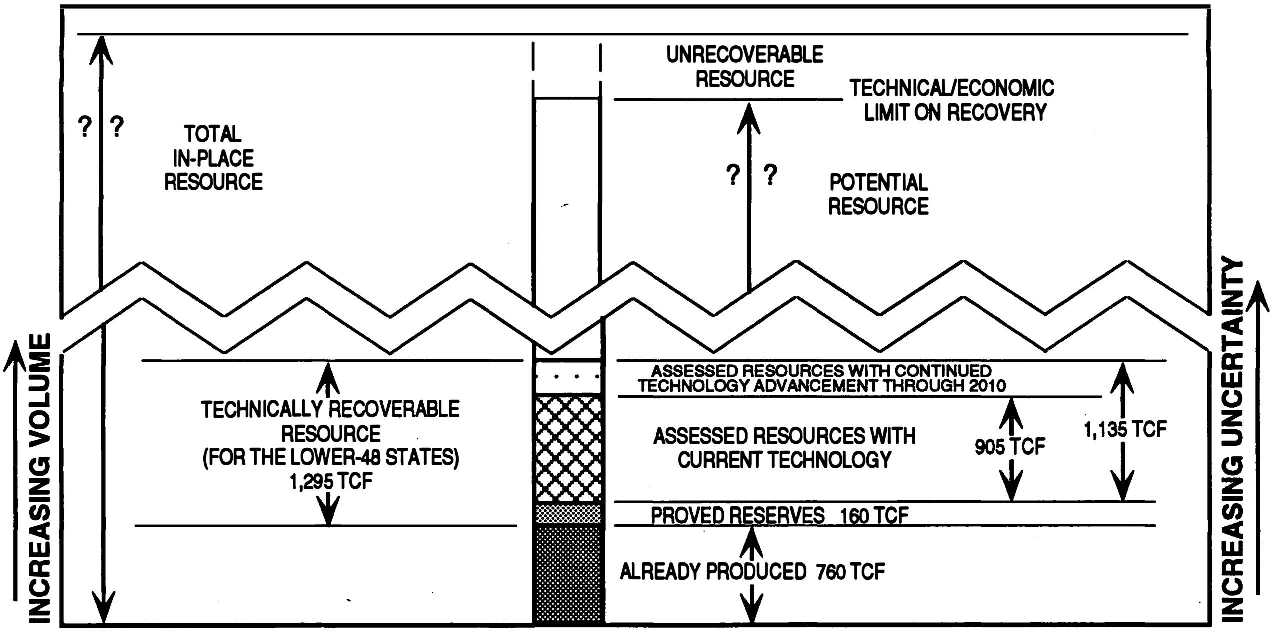

INCREASING VOLUME
? ?
TOTAL IN-PLACE RESOURCE
UNRECOVERABLE RESOURCE
TECHNICAL/ECONOMIC LIMIT ON RECOVERY
? ?
POTENTIAL RESOURCE
TECHNICALLY RECOVERABLE RESOURCE (FOR THE LOWER-48 STATES) 1,295 TCF
ASSESSED RESOURCES WITH CONTINUED TECHNOLOGY ADVANCEMENT THROUGH 2010
ASSESSED RESOURCES WITH CURRENT TECHNOLOGY
905 TCF
1,135 TCF
PROVED RESERVES 160 TCF
ALREADY PRODUCED 760 TCF
INCREASING UNCERTAINTY

Figure 3. Schematic of Natural Gas Resource Base.

thus the recoverable resource base is dynamic and growing. The comparable estimate assuming there is no further advance in technology from 1990 levels is 1,065 TCF. A detailed comparison of the NPC resource estimate to other studies is contained in Chapter One. A more quantitative discussion of the resource base under specific economic, technology, and access assumptions is discussed later in this summary after establishing the economic and technology criteria used in developing the supply assessment (see Supply Curves section of this chapter).

While comparison with other estimates is difficult due to differences in definition and methodology, directionally, the NPC resource estimate is larger by 10 to 20 percent than generally recognized, previously published estimates. This is partly attributable to the explicit NPC recognition of continuing technology advancement and partly to the comprehensive approach taken for evaluating reserve appreciation and tight sands. More importantly, the breadth of participation and consensus approach adopted for the NPC study work gives increased confidence in the overall resource base and the potential contribution from each resource category.

As new knowledge and new technology become available, subsequent forecasts by others would be expected to increase as well. There is uncertainty for any resource base estimate, in part because of the inherent uncertainty in defining any opportunity that remains in the ground. Although estimating tools include risk weighting and other statistical techniques, there is still a tendency to be conservative to enhance credibility. Likewise, time and economic incentives bring technology application to previously marginal and, therefore, probably understated resources.

The following is a detailed discussion of the 1,295 TCF resource base that is shown in Table 1.

Conventional Gas Resources (616 TCF)

The Reserve Appreciation (203 TCF) is that portion of the resource base resulting from the recognition that the currently booked proved reserves are conservative by definition and will continue to grow over time. The 203 TCF is an estimate of that growth expectation from today forward for currently discovered, high permeability conventional gas fields. (An additional 33 TCF reserve appreciation is contained within the tight sands resource discussed below and relates to growth for currently producing low permeability fields.) This resource is incremental gas likely to be added over time in fields that already have produced 760 TCF and contain proved reserves of 160

TCF. Such appreciation occurs as a result of reserve additions from field extensions, new reservoirs, and revisions due to infill drilling, improved technology, enhanced recovery, well workovers, and recompletions. Increasingly sophisticated technologies, such as 3-D seismic, cased-hole well logging, and horizontal drilling, help to make such reserve growth a reality. Historical evidence shows that fields more than 50 years old are still showing significant additions.

NPC analytical work on reserves appreciation involved statistical analysis of a large data base containing reserve estimates for the 1966-1989 period. The results of the analysis showed that reserve additions can be correlated to both time (maturity of fields) and level of activity (drilling). Reserve appreciation statistical results were confirmed by a confidential survey of individual company experience regarding reserves appreciation for a number of specific fields.

The New Fields category (413 TCF) applies to gas yet to be discovered. Since wildcat exploration will be required to find this gas, it is largely based on risked assessments attributing geologic similarities from known areas. Much of it will be at greater depth and in deeper water than historically developed, or in smaller fields if found in more mature areas.

Nonconventional Resources (519 TCF)

For convenience shale gas, coalbed methane, and tight gas are classified together as "nonconventional" gas. Although this is somewhat of a misnomer, the term nonconventional is used because each of these is in a relatively early stage of technical development. Figure 4 shows the most active basins and those with the most significant potential.

For gas from shale (57 TCF), coalbed methane (98 TCF), and tight sands (349 TCF), both public and company sourced evaluations were used to establish likely recoverable estimates. For tight sands, consultants were also used to aggregate extensive data obtained from a confidential survey of current operators and assist in a statistical analysis of historical production data.

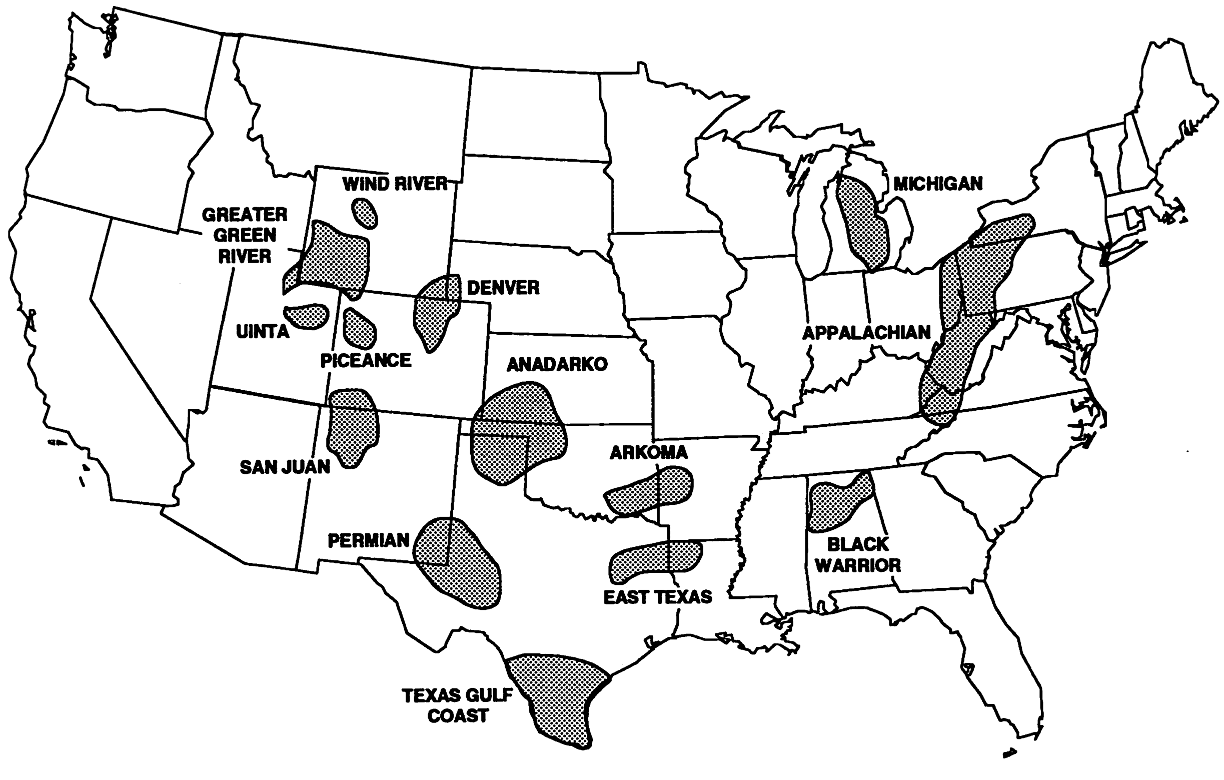


Figure 4. Location of Principal Nonconventional Gas Basins.

It should be recognized that, although the potential tight sands resource base is quite large, the NPC has evaluated in detail only that portion for which sufficient data exist to adequately characterize potential. For example, the U.S. Geological Survey (USGS) has estimated that overpressured tight formations in the Greater Green River Basin alone contain over 5,000 TCF of gas in place. The economic development of most of this and similar in-place potential elsewhere is highly speculative at this time and is expected to require technology or cost/price improvements beyond those considered reasonable in this study. Therefore, only those portions of formations that are currently under development or are expected to be significantly developed during the study period (1990-2010) are included in the 349 TCF assessment for tight gas.

Import/Alaskan Resources

Canadian resource potential has also been examined using evaluation techniques similar to those used for the United States. The NPC estimate of 740 TCF, as shown in Table 2, is larger than generally acknowledged in reports published by others, especially in the relatively accessible western basin (excluding the 317 TCF Frontier). It includes significant coalbed methane (129 TCF) and tight sands (89 TCF). To eventually be competitive, natural gas resources in the frontier areas face the extra transportation burden imposed by their remote location.

Alaska has a considerable gas resource base (180 TCF), but it too suffers the burden of remote location relative to lower-48 markets. Mexico (252 TCF) is currently a net importer of natural gas, but this is expected to reverse over time.

Several countries interested in exporting LNG to the United States also have vast resources in comparison to their indigenous demand potential. These include Nigeria, Venezuela, Algeria, and Norway.

TABLE 2

CANADA
NATURAL GAS RESOURCE BASE
(Trillion Cubic Feet)

Proved Reserves	**72**
Conventional Resources	
Reserve Appreciation	24
New Fields	109
Frontier	317
Subtotal	**450**
Nonconventional Resources	
Coalbed Methane	129
Tight Gas	89
Subtotal	**218**
Total Resources	**740**

Basis — Technically recoverable resources incorporating technology advancement through 2010.

Combined Resource Potential

The cumulative potential of all these sources is shown in Figure 5. Obviously not all of these 2,500 TCF in resources are ultimately destined for the United States. However, the large size of the U.S. market compared to other North American markets, and the strides taken in recent years to implement free-trade principles, make the conclusion of a vast and diverse resource base self-evident. **Therefore, from a resource standpoint, natural gas deserves the same perception as has been long held for coal—namely, that the resource, itself, is not a limiting factor.** While this perception has already taken hold in some quarters, the NPC recommends that it be brought forth for more general adoption both in the marketplace and as a criteria for governmental policy.

SUPPLY POTENTIAL (ECONOMIC AVAILABILITY)

Of equal importance to an adequate resource base is the capability to translate it into timely and competitive supply. Clearly, the natural gas industry is demonstrating such a capability, as evidenced by the level of deliverability that has been maintained for the last decade in the face of declining prices and soft demand. Nevertheless, shortages of the early 1970s

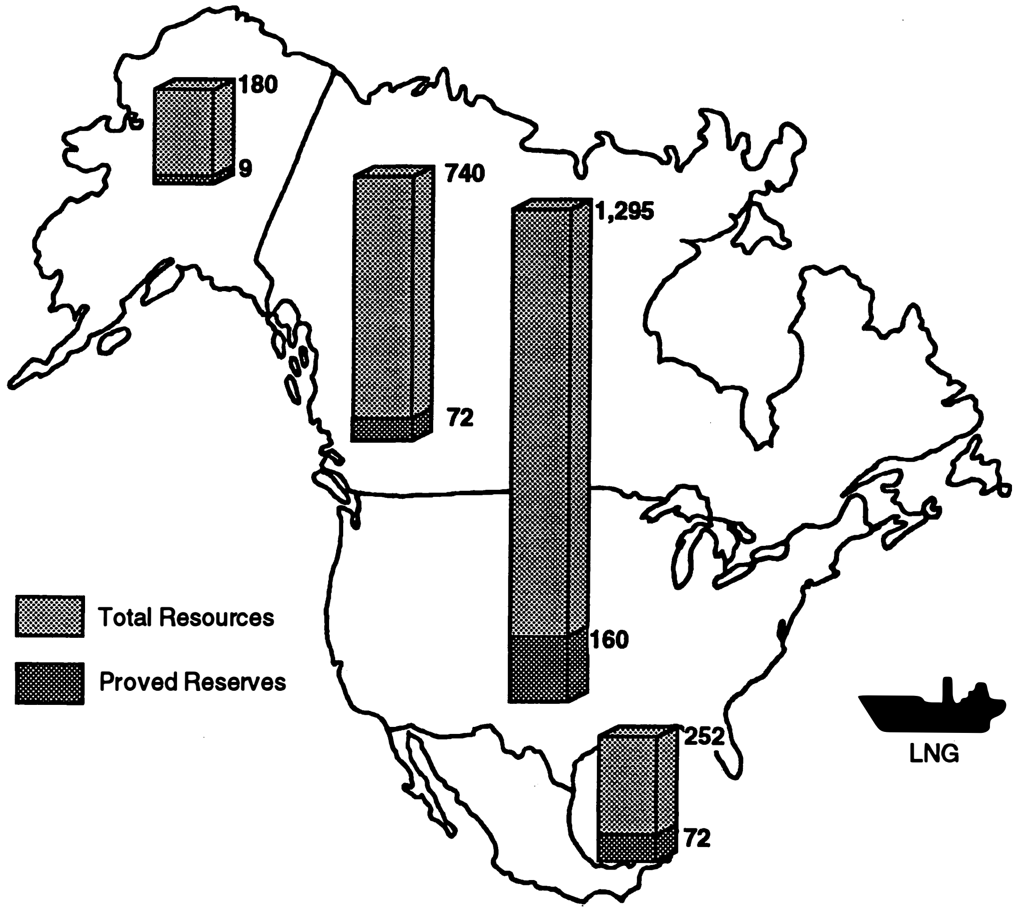


Figure 5. Combined Resource Potential.
(Trillion Cubic Feet)

leave concern as to whether supply can and will be sustained. Recent industry steps to downsize domestic exploration and development activities add to the concern. The historical business and regulatory factors influencing these cycles as well as the physical potential to add new capacity in the future have been examined:

- Natural gas supply can be made competitively available to meet foreseeable demand growth if proper market signals, technology advancement, and environmental management practices are forthcoming.
- Market practices and government policy appear to be moving appropriately in the direction necessary to ensure that supply growth will occur as needed. The recommendations contained in this study that encourage further progress toward a customer-oriented, free market are critical to maintaining momentum in that direction.

Key Supply Parameters

Concurrent with evaluation of the resource base itself, various subgroups assessed finding, drilling, and development costs; technology contribution; environmental trends; and import potential to establish a realistic basis for supply prediction. Confidence in study results was enhanced by integrating assessment of supply dynamics with assessment of each related portion of the resource base itself. The approach and results of this effort are summarized below and discussed in depth in subsequent chapters.

Conventional Gas

Gas from already proved reserves and reserve appreciation should be relatively economic to develop, since both are closely associated with discovered reservoirs and existing infrastructure. An indication of reserve growth potential and its near term significance to supply availability is apparent from reserve addition statistics of the past ten years. As shown in Figure 6, new fields contribute a relatively modest portion of the total proved reserve additions added each year. Reserve growth (new reservoirs, extensions, and net positive revisions) make up the rest.

The chart also demonstrates an exceptional trend for reserve revisions during the last five years. Despite relatively low gas prices compared to the early 1980s, net revisions jumped to an annual average of positive 6.5 TCF in the late 1980s from an historical average of positive 1.5 TCF for the prior 10 years. (Contrary to earlier expectations, newly released EIA data for 1991 show a continuation of this 6.5 TCF trend.) Well recompletion data and Natural Gas Supply Association survey estimates of deliverability support the assumption that such revisions are real. Apparently, producers reacted to difficult times by focusing management attention and technological innovation on maximizing low cost gas recovery in fields already owned. Undoubtedly these results not only demonstrate the resourcefulness of the industry but help explain the persistence of the long-standing "gas bubble."

Substantial new field discovery potential remains in the United States as well as in Canada. Much of the potential is onshore and can be developed with limited lead time once discovery occurs. Directionally, supply from new fields, especially in the United States, will be more expensive than past production, as it will increasingly come from smaller and deeper fields, as well as from fields in deeper waters offshore. Continuing advances in exploration and development technology and efficiency will help ensure that such supply can be produced competitively. Access, especially to the offshore potential, and reasonable environmental regulations are essential as well.

Nonconventional Gas

Production of coalbed methane has risen at an impressive pace in the last few years in part due to tax incentives, but also due to rapidly advancing technology. Similar potential applies to tight sands. A key finding for tight sands is that the cost of production will be much lower than indicated by a 1980 NPC study, *Unconventional Gas Sources*. The 1980 work anticipated massive hydraulic fracturing with great fracture lengths. While fracture lengths have not increased as much as expected, this has been more than offset by new stimulation fluids, better fracture techniques, cavity completion techniques, and significant advances in ability to detect, interpret, and selectively develop potentially productive intervals.

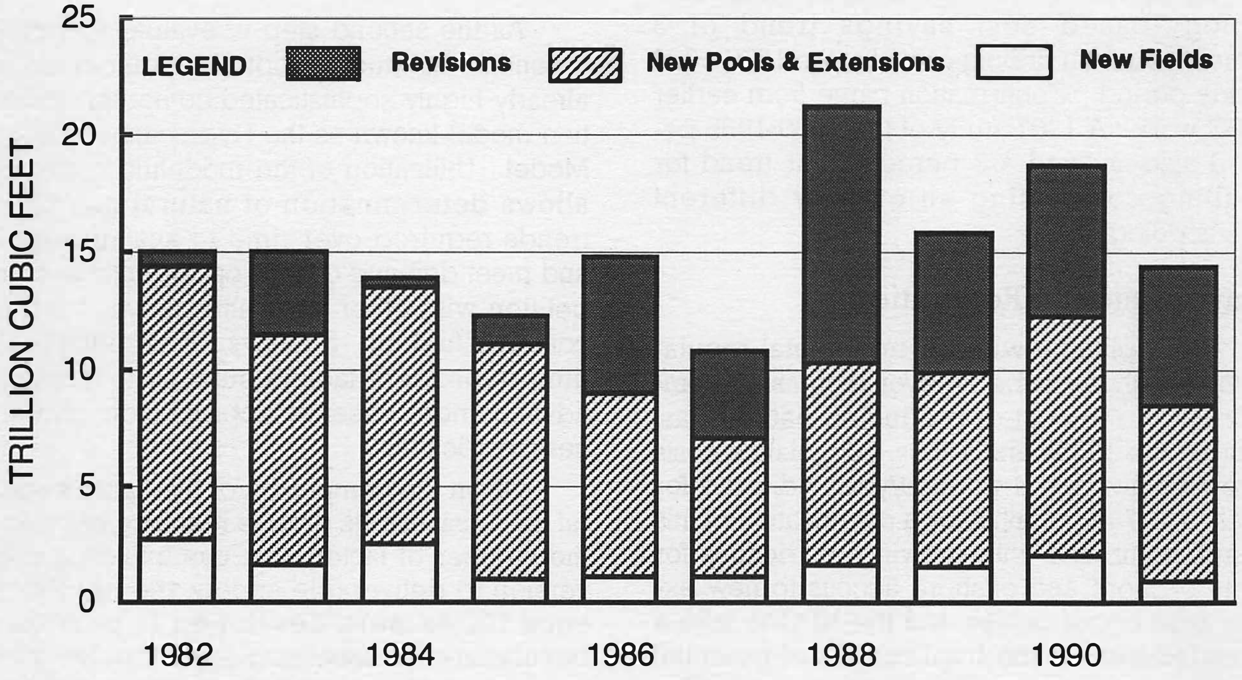


Figure 6. U.S. Lower-48 Historical Reserve Additions.

Technology

Early in the study, it was unanimously agreed that technology could be the most important factor in the future of natural gas supply. A qualitative survey was undertaken by participating companies to assess technology contribution over the last 20 years. It found uniform concurrence that the technology impact has been high in all of the over 50 categories examined. Most respondents not only expect further technological gain, but that the pace will actually accelerate. Substantial anecdotal evidence exists to support this conclusion as do the specific technology discussion papers available in the appendices of this report.

Areas perceived as especially important for technology advancement in coming years include improved exploration tools to enhance success as wildcat opportunities mature, further advances in reservoir stimulation, improved means to detect uncontacted resources in developed fields, and better means to cost-effectively minimize environmental impact.

To calibrate the qualitative survey trends, a consultant undertook a statistical analysis of historical drilling costs, for which detailed data are more available than for other cost categories. After sorting between technology and other factors such as inflation and rig availability, the correlation showed an underlying technology-based cost savings trend of 3 percent/year on drilling costs for the 1970-1989 study period. Confirmation came from earlier NPC work. A 1967 study of the 1950-1965 period also showed a 3 percent/year trend for drilling costs using an entirely different methodology.

Environmental Regulation

Compliance with environmental regulations continues to be an ever increasing component of the cost of producing natural gas. During the 1970s and 1980s, compliance costs grew an average 4 percent/year, adjusted for inflation. The potential for a continuation of this trend, combined with growing restrictions for both onshore and offshore access to new exploration opportunities, led the NPC to take a detailed look at the implications of potential new restrictions on exploration and production operations. Building on earlier work done by organizations such as the API, a range of possible applications was established for such legislation as the Resource Conservation and Recovery Act (RCRA), the Clean Water Act (CWA), the Safe Drinking Water Act (SDWA), and the Clean Air Act (CAA).

The general conclusion, and the assumed basis of the Reference Cases reported in this study, is that reasonable application of new rules using a balanced cost/benefit approach would continue to raise compliance costs at a pace somewhat below the historical rate of increase but should not have an overwhelmingly adverse effect upon overall gas-producing costs—aggregating to about 10 percent above today's already carefully controlled and monitored operations.

However, as elaborated on later in this volume, there is substantial risk that such balance will not prevail. Access restrictions and extreme regulation could significantly constrain supply and raise costs at an accelerating pace well above the historical rate of increase unless today's process is modified so as to better balance environmental risk and other national needs. For natural gas this includes recognition of its "downstream" environmental attractiveness as a clean fuel.

Modeling Approach

As the second step in evaluating supply potential, the study adopted and modified an already highly sophisticated computer simulation model known as the Hydrocarbon Supply Model. Utilization of the modeling approach allows determination of natural gas price trends required over time to sustain supply and meet demand growth opportunity in competition with other user alternatives such as coal and fuel oil. It allows for recognition of time-dependent factors such as technology advancement, reserve appreciation, and access restrictions.

Given the complexity of the nation's natural gas business, its diverse resource base, and the number of factors that can influence conversion to deliverable supply, the two Reference Cases were developed to provide a benchmark for assessing supply potential in the context of expected market opportunities.

Several assumptions that are critical to the supply results were made for both Cases:

- Supply will be driven by market need. The excess of supply prevalent for the last few years is believed to be the result of market transition. It is assumed that it will dissipate with time in response to market signals. For the Reference Cases, it is assumed that producers will have "perfect foresight" of market opportunities and price trends when adding new reserves and delivery capacity as currently available supply undergoes economic depletion.
- It is assumed the current supply-industry restructuring will self-correct when necessary. There will be no regulatory, contract practice, transportation, or storage limitations that distort market signals from reaching the supply community in a timely manner.
- Industry profitability and reinvestment ratios will vary year to year and individually, as circumstances dictate, but it was assumed that they will generally be in line with historical levels (i.e., averaging approximately 5 percent real annual rate of return after tax and 70 percent expenditure/income).
- There will not be significant tax distortions or free-trade restrictions that bias natural gas supply type or source—either national or international in nature. Specifically, it is assumed that Section 29 tax credits are not extended beyond 1992.
- There will be no further exploration or development access restrictions than now applicable under existing laws and moratoria. It is assumed that existing offshore (OCS) moratoria are not renewed at the end of their current terms. Estimated first exploration opportunity after assumed expiration of the moratorium is shown on Table 3.
- Technology advancement will continue at a pace consistent with survey indications. Specifically, it is anticipated that drilling costs will benefit from a technological improvement estimated at 4 percent/year. Resource recovery will increase approximately 0.5 percent/year for conventional gas and 2 percent/year for nonconventional gas.

TABLE 3

OCS MORATORIUM AREAS ESTIMATED FIRST EXPLORATION ACCESS

Eastern Gulf	1997
North Atlantic	2010
Mid-Atlantic	2002
Florida Straits	2015
California	2005
Washington/Oregon	2010

These assumptions are both achievable and appropriate for the purpose of characterizing what can be accomplished consistent with the NPC vision of sound government policy and a healthy market environment.

In addition to the judgments listed above, the model's methodology and numerous explicit assumptions were closely examined, including: resource definition by field size, depth, and basin within both the United States and Canada; onshore and offshore drilling and development cost parameters; new field finding rates; LNG development, shipping, and terminal costs and capacities; etc.

The judgments and explicit assumptions used for modeling analysis are subject to external influence and technical uncertainties that will vary from year to year as events unfold. Therefore, the Reference Cases and sensitivities described below are intended to be instructive trend indicators rather than forecasts. Neither Reference Case nor any sensitivity is considered more or less probable than any other.

Supply Implications of Reference Case 1 (Moderate Energy Growth Scenario, 1991-2010)

Reference Case 1 represents the stronger demand outlook of the two Reference Cases chosen. Although it does not represent maximum gas demand (or supply) potential, it does provide a sound basis for defining supply capability within a realistic framework of a growing market. Directionally, it demonstrates that natural gas supply can be made competitively available to meet growing demand opportunity through 2010 (the last year for which detailed demand analyses were conducted.)

Specific model results and trend indicators are summarized in Table 4. Under this scenario, gas supply increases by 25 percent from 19.3 TCF in 1991 to 24.3 TCF in 2010 (equivalent to 25 QBTU). Figure 7 shows the supply trend and supply mix by year. (For convenience of comparison, Reference Case 2 supply is shown in Figure 8).

For Case 1, in response to competitive market requirements, domestic production rises 18 percent from 17.5 TCF in 1991 to 20.7 TCF by 2010. By 2010, 29 percent of domestic supply comes from nonconventional supplies as opposed to 12 percent in 1991. Imports double to 3.6 TCF/year by 2010 or 15 percent of total supply. Most of the import gain is expected to be Canadian gas from traditional western producing regions. It is not expected that North Slope Alaskan or Canadian frontier gas (MacKenzie Delta) will be competitive within the 2010 time frame. LNG imports rise to 0.3 TCF/year, utilizing less than one half of existing capacity at the four available terminals.

Under Case 1, utilization of domestic deliverability increases sharply in the next few years. Utilization has stayed in the low 80 percents for the last five years but approaches 94 percent by 1995, anticipating that recent cutbacks in activity continue for the interim. Afterwards, it would likely stay near year-round maximum utilization, estimated to be 96 percent.

The model results indicate that gas will remain competitive in the market under the demand assumptions of this scenario, even though the average wellhead price necessary to encourage adequate supply increases over

TABLE 4

REFERENCE CASE 1 SUPPLY SUMMARY
MODERATE ENERGY GROWTH SCENARIO

	1991	1995	2000	2005	2010
Supply, TCF/year					
Domestic	17.5	17.9	18.6	20.1	20.7
Imports	1.8	2.5	3.1	3.0	3.6
Total	19.3	20.4	21.5	23.1	24.3
Deliverability					
Utilization, %	83	94	96	94	95
Wellhead Price					
Texas Gulf Spot, 1990$/MMBTU	1.27	1.98	2.88	2.76	3.47
Gas to Oil, %	40	60	79	64	72
Well Completions					
Gas	9,800	9,800	12,500	14,400	18,400
Proved Reserves, TCF					
Lower-48	156	143	137	148	153
Canadian	70	64	66	71	77
Memo—Oil Price					
1990$/Barrel	18.38	19.01	21.10	25.14	27.85
1990$/MMBTU	3.16	3.27	3.63	4.34	4.80

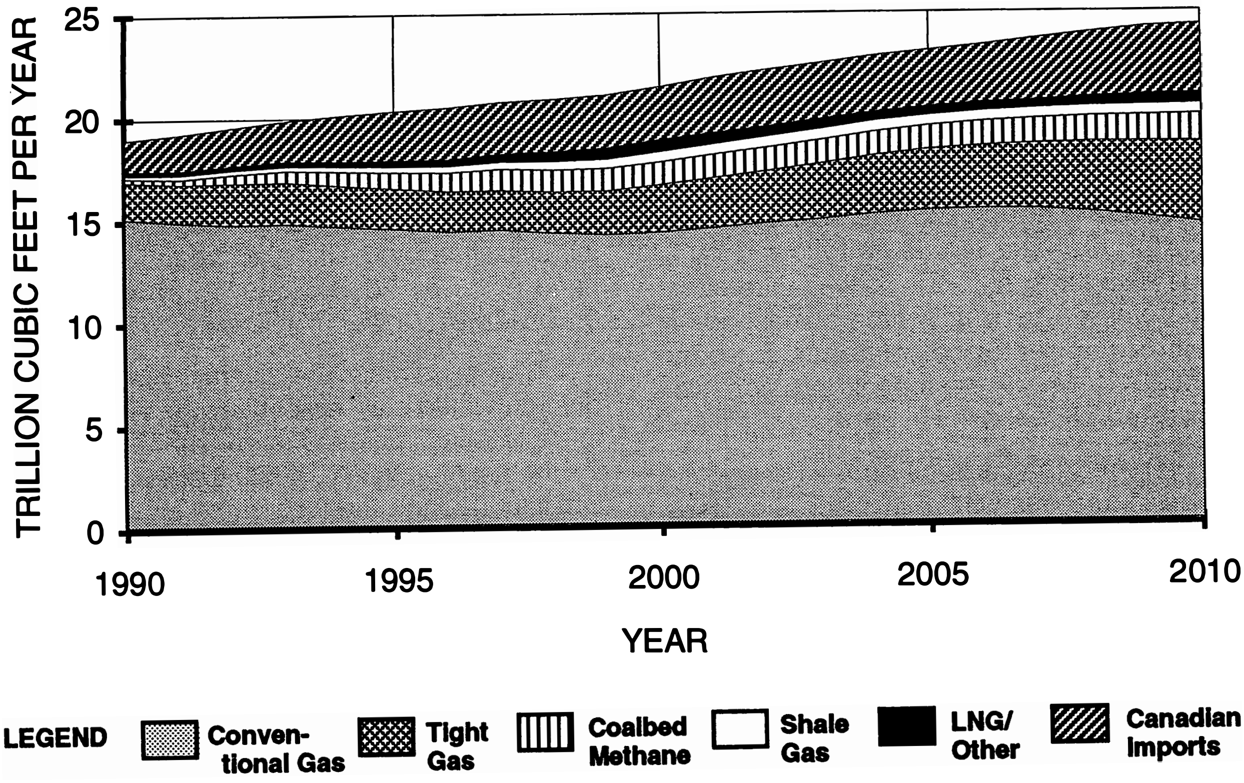


Figure 7. U.S. Lower-48 Gas Supply—Reference Case 1.

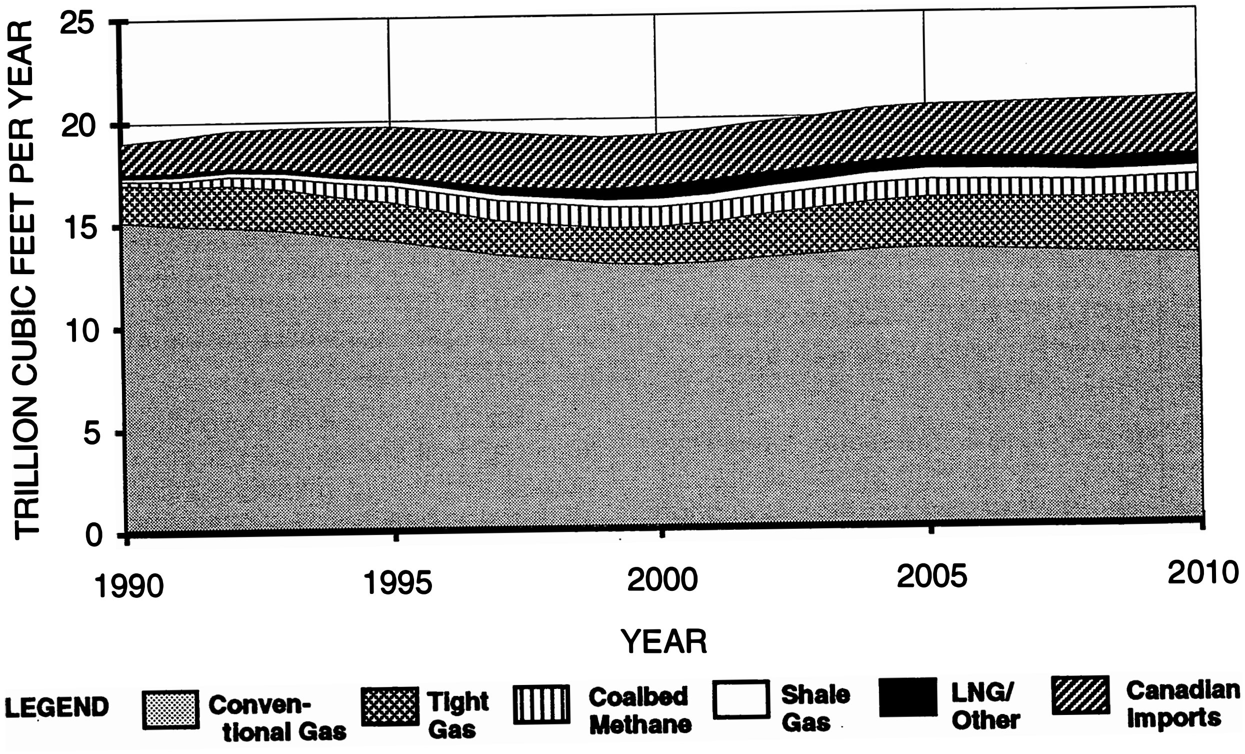


Figure 8. U.S. Lower-48 Gas Supply—Reference Case 2.

the 20-year study period (see Figure 9). Model results show a steady increase in price until the turn of the century, driven on the supply side by increasingly expensive incremental supply from conventional sources. This can be seen from the drilling requirements shown in Figure 10. Drilling for conventional gas doubles during the next ten years followed by a rapid buildup for tight sands drilling thereafter. Once full deliverability utilization is reached, at the turn of the century, it plateaus at about $2.80/MMBTU ($1990) for a decade before rising to about $3.50/MMBTU in 2010.

Compared to crude oil on a BTU equivalency basis, the gas wellhead price increases from about 42 percent today to about 72 percent by 2010. This is a substantial increase at the wellhead, but somewhat offset at the burnertip by increased efficiency of transportation due to higher throughputs. Demand-side factors and burnertip price comparisons that support this competitive supply/demand balance are discussed in Volume III, Demand and Distribution. Generally, burnertip prices remain competitive due to rising alternative fuel costs, increasingly stringent environmental standards that natural gas more easily meets, and the relatively low capital requirements and high efficiency of natural gas facilities.

Figure 12 adds a 30-year historical perspective. Neither the demand nor price exceed historical peaks. Indeed, the historical peaks and valleys generated by misregulation stand out as an anomaly.

Supply Implications of Reference Case 2 (Low Energy Growth Scenario, 1991-2010)

Reference Case 2 represents a relatively weak demand outlook with the challenge for natural gas compounded by the assumption that oil prices remain near today's level through the next 20 years. Results are summarized in Table 5 and Figures 8, 9, and 11. Figure 13 adds a 30-year historical perspective to the Case 2 results.

Modeling results indicate natural gas supply can competitively respond with total supply increasing slightly from 19.3 TCF/year in 1991 to 20.8 TCF/year in 2010. Domestic production would be sustained at close to current levels. Imports, primarily from Canada, would increase about 75 percent to 3.1 TCF/year. Lower producer activity in proportion to perceived lower demand and lower competitive crude oil pricing, would yield a deliverability utilization similar to Case 1—namely, an increase to essentially full utilization by the turn of the century. Wellhead price by 2010 would be approximately 0.75 $/MMBTU lower than Case 1.

The possibility that overall domestic production would stay essentially constant results in substantially different service industry needs for the next ten years. Drilling stays essentially constant through the turn of the century under Case 2, compared to a doubling under Case 1. Thereafter, service industry needs would still increase due to smaller field size and increased utilization of nonconventional gas resources made economic by the combined effect of technology advance and higher wellhead prices than today.

Long-Term Supply Sustainability (1991-2030)

The modeling approach was also used to assess the sustainability of competitive gas supply for the longer term beyond 2010. Many current natural gas users (particularly residential and commercial with limited fuel switching capability) and potential new customers (particularly capital intensive electric utility and industrial) need assurance of supply beyond the 20-year study period. While such security may be individually attainable through term contracting, it is appropriate to look at the underlying aggregate long-term gas supply potential for additional comfort.

For the purpose of this evaluation, gas demand and oil and natural gas prices were assumed to rise in a manner similar to Case 1. With these benchmarks, gas supply potential was assessed at various maximum price levels—specifically $1.50, $2.50, $3.50, and $4.50/MMBTU (1990$). The resulting supply capability is shown in Figure 14.

Results suggest that gas supply cannot be sustained even for the near term at $1.50/MMBTU but is readily sustainable well beyond 2010 within the range of $2.50 to $3.50/MMBTU (1990$). Compared to the oil

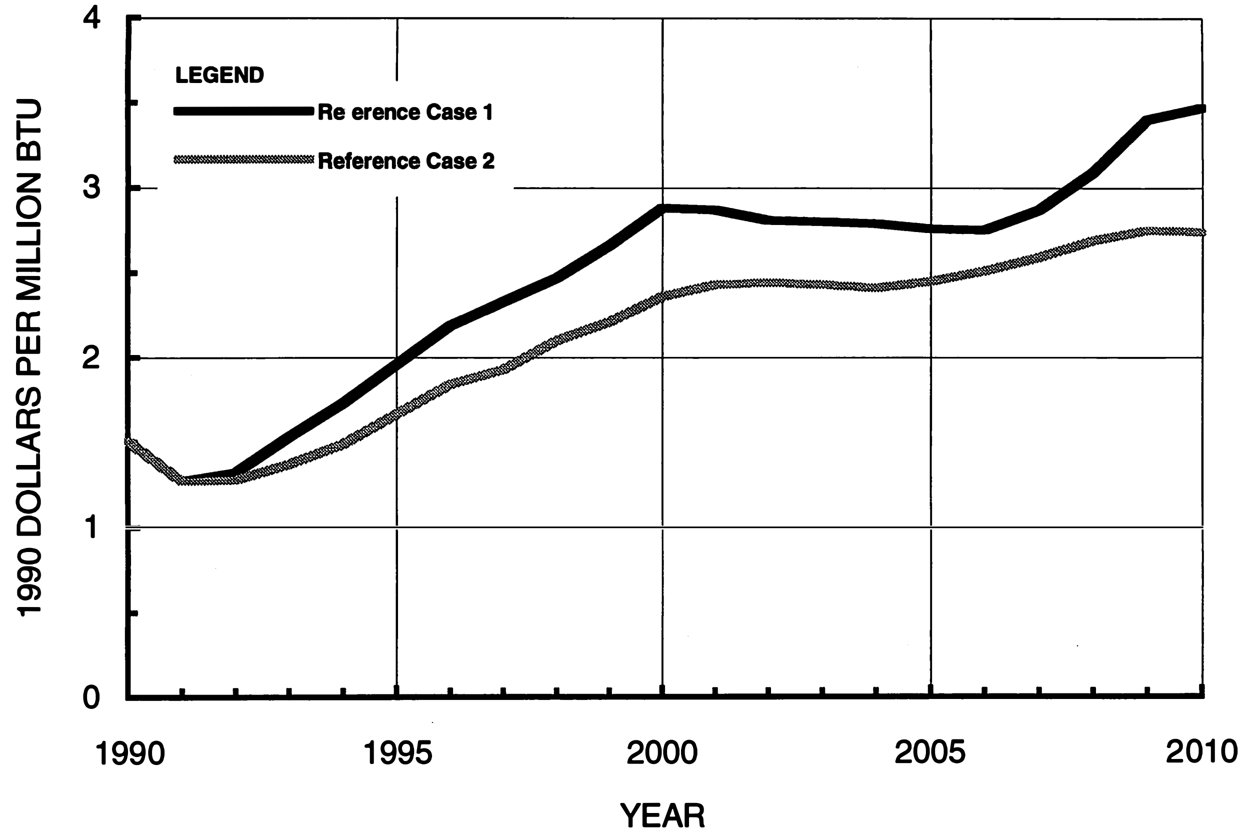


Figure 9. Texas Gulf Spot Wellhead Gas Price.

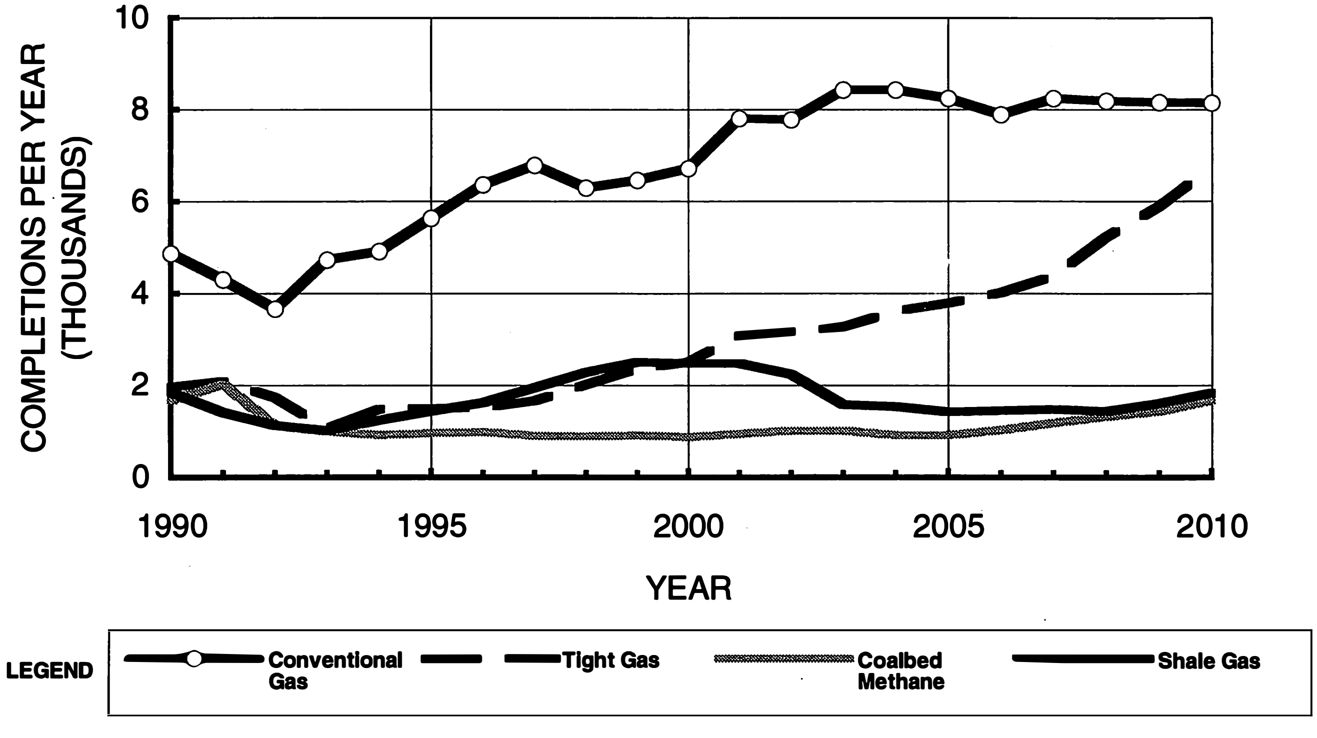


Figure 10. U.S. Lower-48 Gas Well Completions
by Type of Resource—Reference Case 1.

TABLE 5

REFERENCE CASE 2 SUPPLY SUMMARY LOW ENERGY GROWTH SCENARIO

	1991	1995	2000	2005	2010
Production, TCF/year					
Domestic	17.5	17.2	16.4	17.7	17.7
Imports	1.8	2.5	2.7	2.9	3.1
Total	19.3	19.7	19.1	20.6	20.8
Deliverability					
Utilization, %	83	94	96	96	96
Wellhead Price					
Texas Gulf Spot, 1990$/MMBTU	1.27	1.61	2.36	2.45	2.74
Gas to Oil, %	40	60	81	77	80
Well Completions					
Gas	9,800	6,700	9,100	12,500	12,200
Proved Reserves, TCF					
Lower-48	156	136	122	125	127
Canadian	70	63	58	61	61
Memo—Oil Price					
1990$/Barrel	18.38	15.50	17.00	18.50	20.00
1990$/MMBTU	3.16	2.67	2.93	3.19	3.45

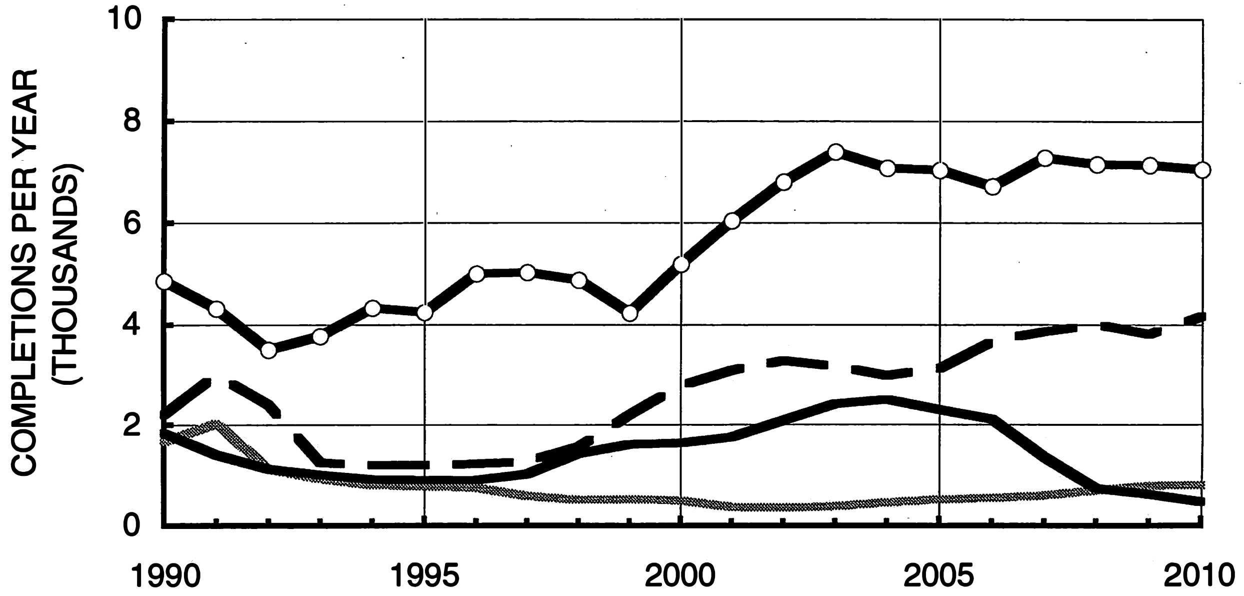


Figure 11. U.S. Lower-48 Gas Well Completions by Type of Gas Resource—Reference Case 2.

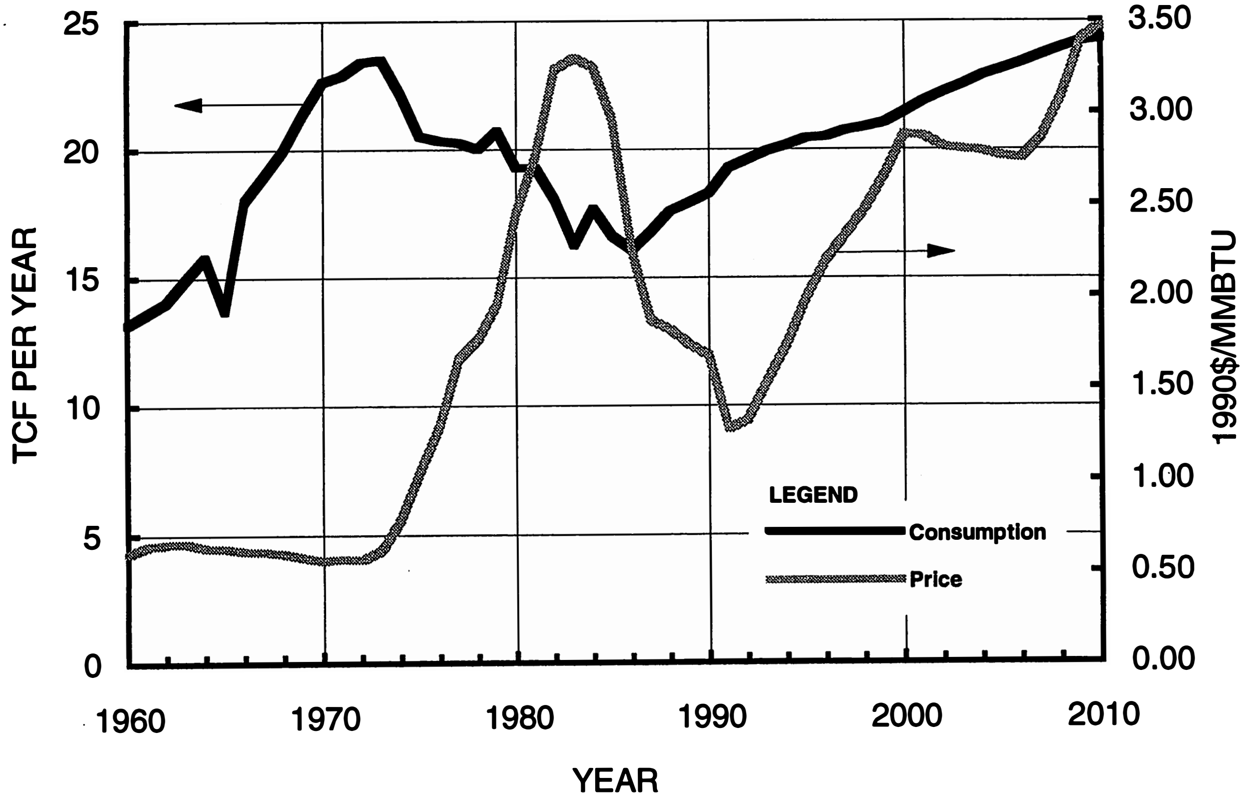


Figure 12. U.S. Lower-48 Consumption and Texas Gulf Spot Wellhead Gas Price—Reference Case 1.

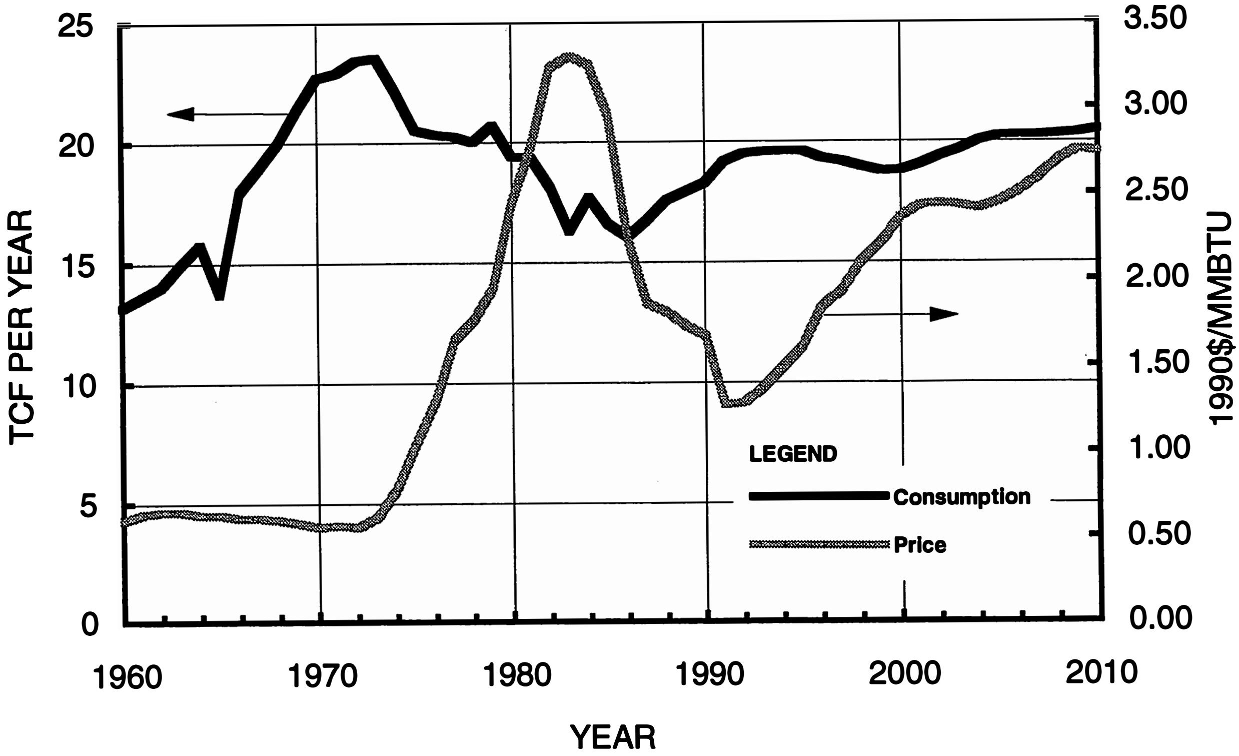
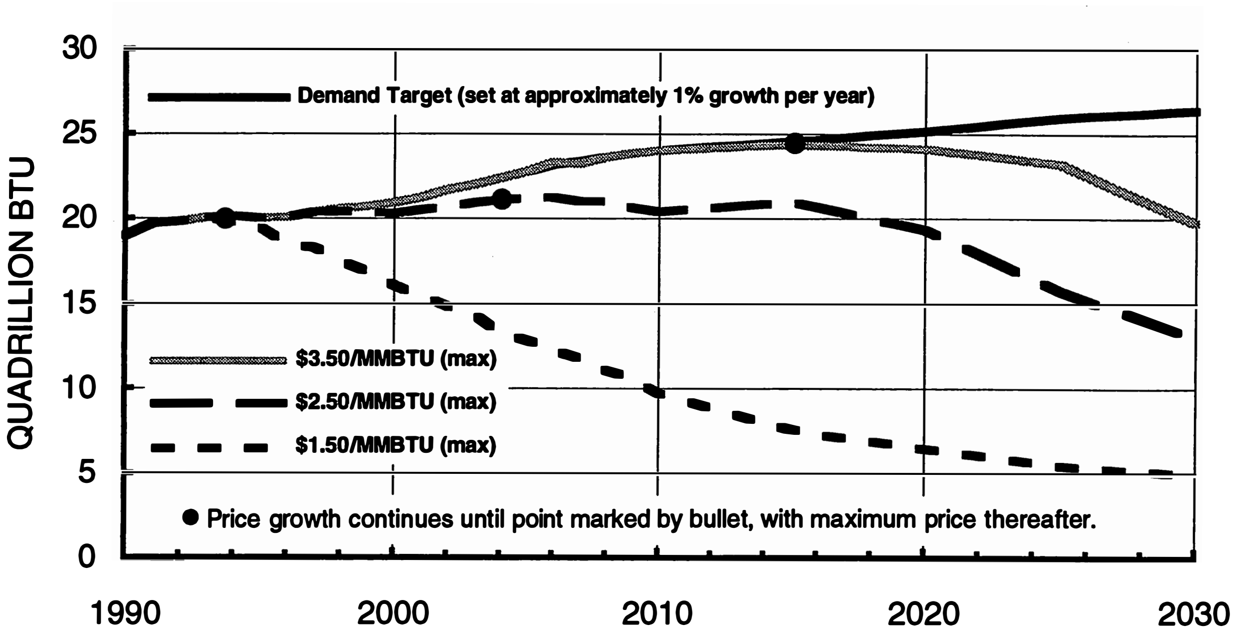


Figure 13. U.S. Lower-48 Consumption and Texas Gulf Spot Wellhead Gas Price—Reference Case 2.



NOTES: 1. Assumes technology advancing throughout the period.
2. Prices are in 1990$ per million BTU for Texas Gulf Spot.
3. Demand target fully satisfied through 2030 at prices which do not exceed $4.50/MMBTU.

Figure 14. Long-Term Gas Supply at Various Maximum Wellhead Price Levels.

price assumption for 2030, this yields a wellhead BTU equivalency for gas between 60 and 70 percent.

Import dependence would rise from 11 percent today to 25 percent in 2030, primarily gas from Canada. While this is a substantial increase, it remains modest compared to today's U.S. 50 percent oil dependence and compared to other developed gas markets around the world. For example, Japan is essentially 100 percent dependent on import LNG for its gas supply and willing to pay approximately 100 percent of crude oil equivalency as well.

Figure 15 shows the mix of domestic supply for the maximum case. Conventional supply begins to drop around 2010, and is increasingly replaced by tight sands production.

Figure 16 compares cumulative production over the 40 years to the resource base expected to be available to support continuing development activity. Note that the starting point includes 760 TCF already produced as of 1990. The resource base is expected to continue growing as new technology becomes available. Even in 2030 the remaining resource base should be substantial.

Supply Curves

Another traditional approach to defining long-term supply potential is to subdivide the recoverable resource base into various cost/price categories. Although such an approach cannot adequately take into account dynamic factors such as time-dependent reserve appreciation, technology advancement, and the changing competitiveness of alternative fuels, it does provide a means of visualizing the underlying economic resource potential and the important contribution technology advancement can make in increasing that potential.

Utilizing explicit detailed assumptions similar to those previously stated for the modeling work used to develop the Reference Cases, aggregate "supply curves" can be developed for specific fixed price and technology assumptions as shown in Figure 17. Several conclusions can be drawn from analysis of these curves:

- By definition, the 160 TCF proved reserves are economic under current technology and wellhead prices. Even at $1.50/MMBTU, reserve additions are likely to nearly double this figure.

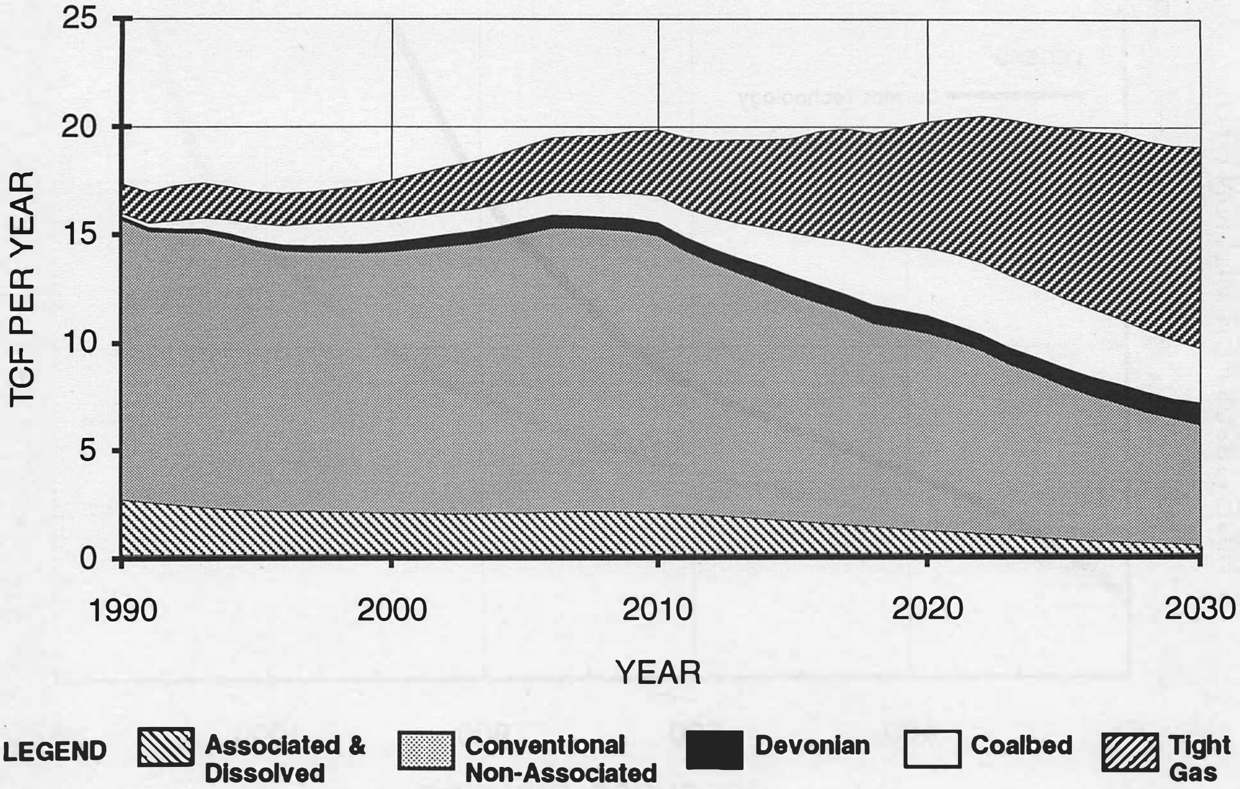


Figure 15. Total Lower-48 Dry Gas Production—Maximum Demand Case.

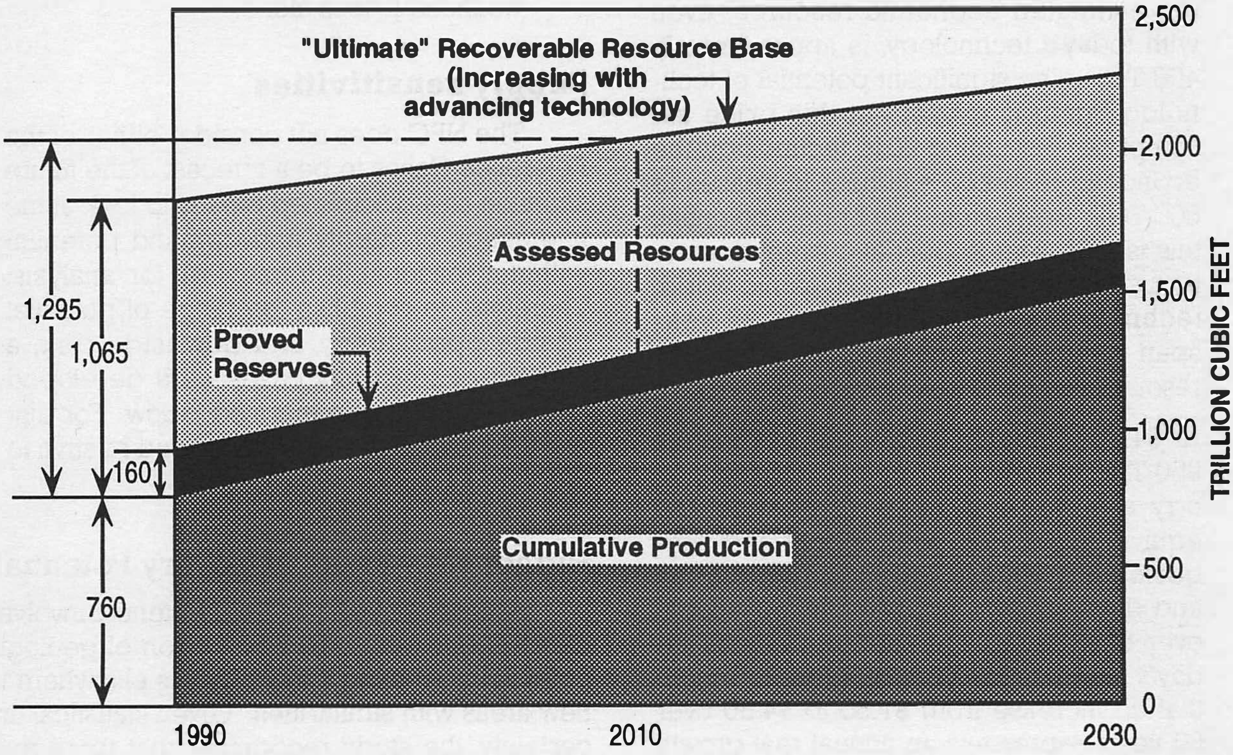


Figure 16. Gas Resource Base.

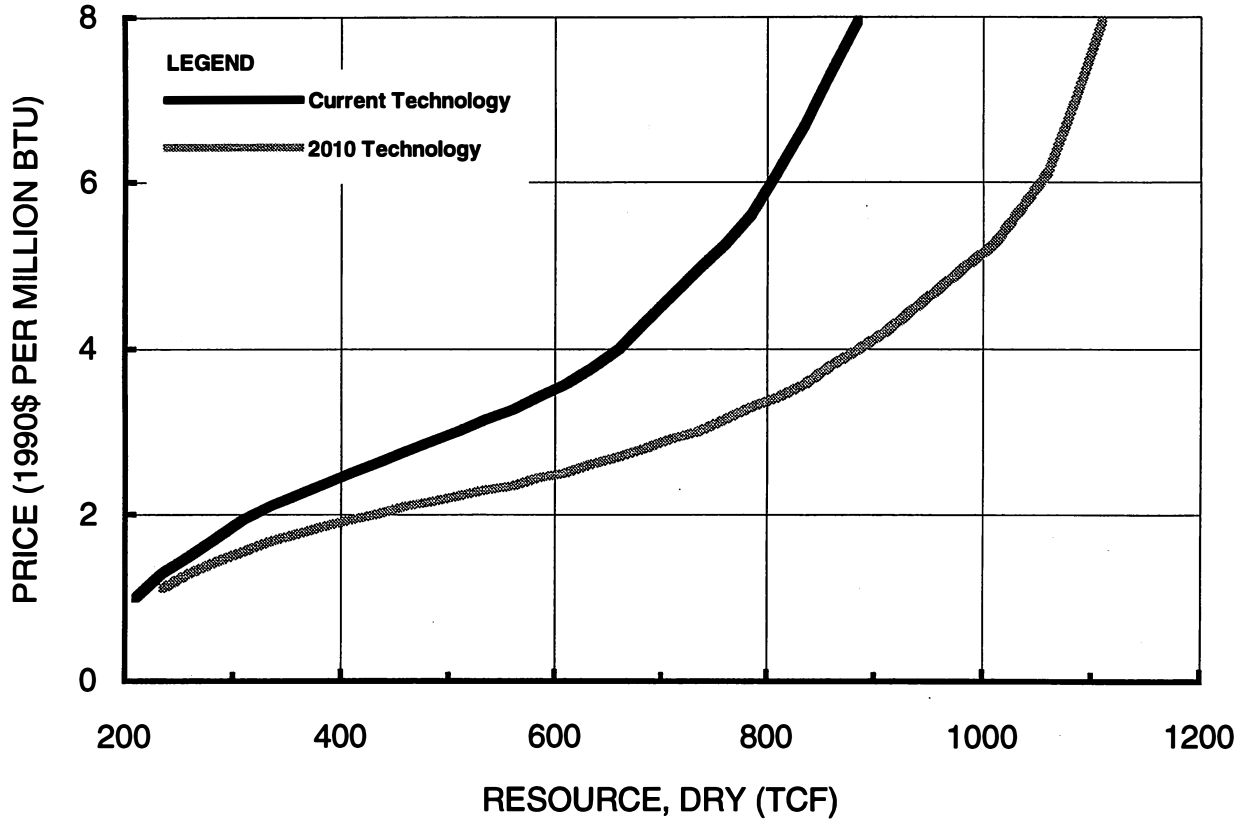


Figure 17. U.S. Lower-48 Gas Supply Curves.

- At prices commensurate with Reference Case 2 of $2.50/MMBTU (1990$) in 2010, the estimated economic resource, even with today's technology, is approximately 400 TCF. The significant potential of technology gain is evident at this price assumption. Assuming 2010 technology, the economic resource estimate increases to 600 TCF. Even excluding import potential, this is a 35-year supply at current domestic production levels. In a dynamic world, technology gain within such a 35-year span would likely increase the economic resource further.
- At $4.50/MMBTU (1990$), approximately 950 TCF is economic under 2010 technology assumptions. This represents the equivalent of a 60-year supply and suggests an immense menu of exploration and development opportunities available over time to replace and supplement today's production. It is of interest to note that an increase from $1.50 to $4.50 over 60 years represents an annual real growth rate of less than 2 percent/year—clearly substantial over such a long time but rather small annually in comparison to the ± 50 percent swing seen in 1992 monthly wellhead prices alone.

Supply Sensitivities

The NPC does not consider either of the Reference Cases to be a forecast of the future so much as a disciplined means to look at the interaction of supply and demand potential within a reasonable framework for analysis. Therefore, to establish the range of potential upside opportunity and downside risk, a number of sensitivity cases were developed and analyzed as summarized below. For discussion purposes all are described relative to Reference Case 1.

Higher New Field Discovery Potential

Assessment of new field potential involves detailed basin-by-basin evaluation of geologic potential attributing known results elsewhere to new areas with similarities. Given statistical uncertainty, the study recognizes that there may even be basins that have been completely overlooked (for example the Norphlet trend in the Gulf Coast Basin was only given limited recognition as recently as 10 years ago). Although 50 TCF has been included in the NPC resource estimate to accommodate this possibility, the estimate of new fields potential could still be conservative by as much as another 100 TCF. Should this prove to be the case, additional supply would become economic, increasing gradually to 1 TCF/year by 2010. Competitive price could be as much as $0.50/MMBTU lower in the later years, anticipating that larger typical new field size would lower unit development costs.

Higher Import Potential

Canadian resources are relatively less exploited than those in the lower-48 states. Upside potential could be as great as 50 percent compared to the NPC estimate for the Western basins. There is also the possibility that Mexico's 252 TCF resource base will be developed at a pace to displace imports from the United States and bring net exports of 0.5 TCF/year to the United States by 2010. Together these could add over 1 TCF/year to U.S. markets by 2010 and reduce the competitive price by about $0.50/MMBTU. Conversely, were Canada to impose export growth restrictions, U.S. imports could be reduced 0.5 TCF with competitive price raised approximately $0.25/MMBTU.

Rapid Tight Sands Development Potential

Although the NPC study work on tight sands suggest impressive potential in the coming years, there is uncertainty as to the practical pace at which activity buildup can occur. Accordingly, a judgmental growth rate restraint of 20 percent/year was imposed on tight sands development investment in the Reference Cases. Accelerated development without such an assumption yields an additional 1 TCF/year by 2010.

No Tight Sands Technology Advance

Conversely, technology advance is expected to be rapid for tight sands as activity levels increase above today's rather modest programs. Should the assumed 2 percent/year recovery gain not materialize, production by 2010 would likely be 1 TCF/year lower.

High Environmental Regulation

Recognizing the exposure to more stringent regulation than assumed for the Reference Cases under a balanced cost/benefit philosophy, a sensitivity case was defined incorporating additional regulatory initiatives based on publicly proposed, more stringent interpretation or amendment to RCRA, CAA, SDWA, and CWA. While this does not represent a "worst case," it does incorporate substantially more aggressive environmentally motivated constraints on supply than assumed for the Reference Cases. For example, the sensitivity case assumes RCRA would be amended to apply more extensively to exploration and production activities than assumed for the Reference Cases. As a specific illustration, tanks would replace surface impoundments (pits) in most situations. In combination with other specifically defined changes, individual drilling costs for new wells in this sensitivity case would be increased by 50 percent. Modeling results indicate supply would be decreased at least 2 TCF/year by 2010 due to earlier well abandonment and reduced drilling caused by higher capital and operating costs.

Forecast Uncertainty

The range of supply required to satisfy demand for the moderate versus low energy growth scenarios (Case 1 vs. Case 2) illustrates the hazard and uncertainty facing the producer community in coming years. Obviously, the subjective assumption of "perfect foresight" is not going to occur in the real world.

As an alternative to the presumption of such foresight, it is possible that demand will continue to linger for a few years near the levels of the low energy growth scenario while perceptions of a stronger market bring forth new supply sufficient to meet the higher needs of the moderate energy growth scenario—or vice versa. This could be accentuated if regulatory reform is delayed or otherwise less than successful. Price movements could be erratic as a result.

As seen in Figure 18, two sensitivities using different assumptions on near-term reserve additions and deliverability demonstrate the degree to which price instability could occur if market signals are poorly transmitted. As regulatory and contracting

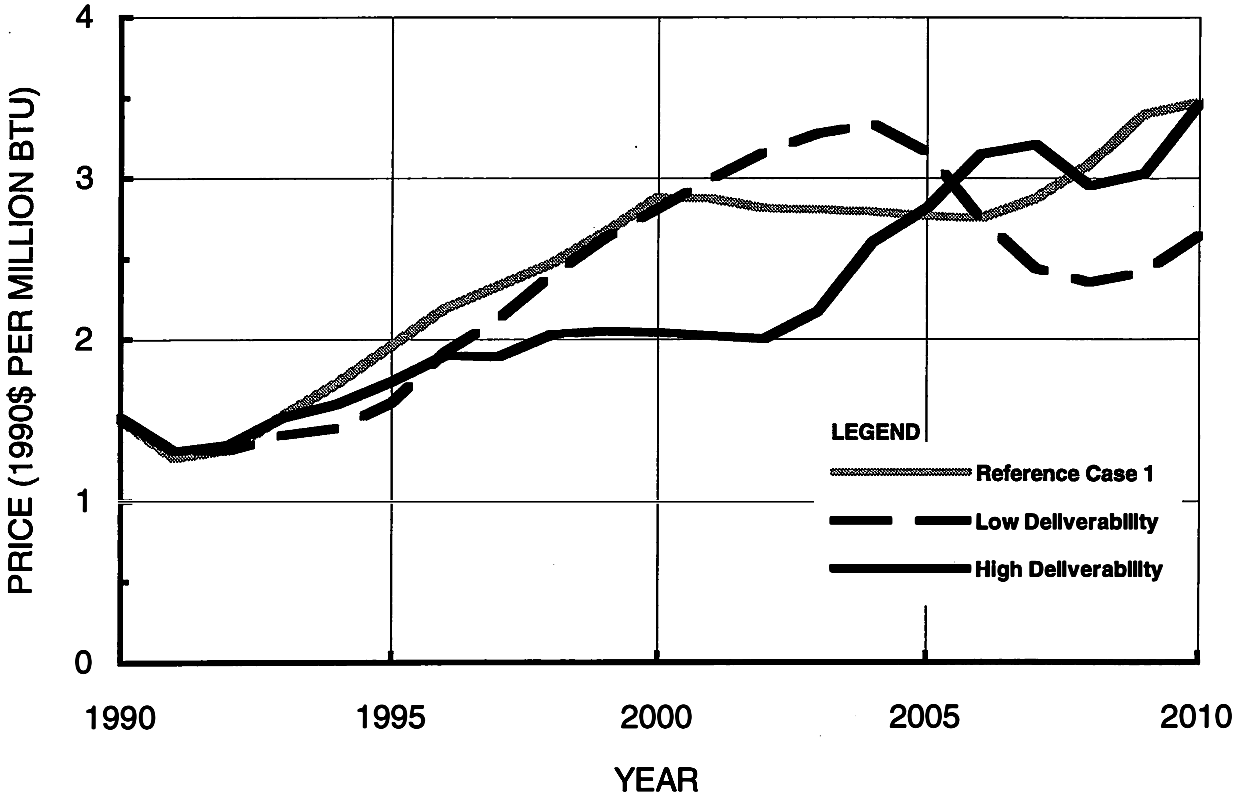


Figure 18. Price Uncertainty—Texas Gulf Spot Wellhead Price.

practices evolve in response to market need, new contract forms and new risk management tools such as the futures market can be used to minimize such price swings for producers and consumers alike. Increased flexibility to fully utilize transportation and storage systems can also cushion market cycles.

POTENTIAL CONSTRAINTS AND OPPORTUNITIES FOR SUPPLY

Producer/Service Company Rebound Potential

Rather than relying on specific numerical projections of the future for confidence in long-term supply security and reliability, it is perhaps more appropriate to look at underlying fundamentals of the industry.

Recent industry downsizing and declines in drilling activity in North America have raised concern that natural gas supply may prove unable to respond to future market needs. While driven largely by oil considerations rather than natural gas, the statistics are nevertheless unpleasant. Gas well drilling has reached its lowest point in over 15 years. Jobs in the oil and gas extraction sector are down 50 percent in ten years. Data indicate somewhat lower natural gas reserve replacement figures for 1991 and the possibility of significantly lower replacement in 1992. There is concern that consequent decline in excess deliverability could bring decreased supply reliability. Recent decisions in Oklahoma and Texas that modify historical prorationing procedures compound the concern.

The NPC believes these events are primarily the result of economic signals transmitted by the combined influence of market demand, domestic recession, and better investment opportunity elsewhere. Therefore, they are correctable with time if market signals so dictate.

There is evidence from the past that supply will come forth as market signals dictate. Admittedly, past swings, both up and down, were exaggerated by regulatory distortions. Nevertheless, the industry's ability to respond was clearly demonstrated. The pace at which supply responded positively in the 1970s to increased price incentives suggests supply response time can be rapid indeed! Figure 19 compares drilling activity response during that period to the projected requirements under Reference Cases 1 and 2. Hopefully, with the ongoing transition to a market responsive rather than regulatory responsive business environment, lead times for supply can be even shorter than in the past.

Examination of resource potential and producer/service company capability suggest current economics for both oil and gas and cost efficiency programs, not lack of gas prospects, are driving the current industry contraction. To the degree that greater efficiency is the result, ability to respond quickly to growth opportunity for gas will be enhanced rather than reduced. Additional evidence of "rebound" potential comes from a survey of recent R&D expenditure patterns for producers and service companies. Expenditures directed at supply-side technology appear to be holding steady, and in some cases, increasing for the survey participants. Furthermore, asset sales, and restructuring programs by many of the majors may have the appearance of overall domestic industry cutback but may in fact be primarily a shift toward a larger role for independents and other smaller producer companies.

Decline of Unused Deliverability

It is anticipated that deliverability utilization will increase over time as price deregulation eventually brings overall supply/demand into balance, and producers reinvest as needed to offset depletion and competitively meet overall demand growth. While extra deliverability has been available to help meet seasonal balancing needs, this will increasingly be met by fuel switching, "unbundled" gas storage, and transportation flexibility.

An examination of the historical regulatory actions that have contributed to the so-called "gas bubble" suggest that the excess deliverability it represents is more a carryover of past market distortions than current market signals. While it is possible that optimistic perceptions of market strength could continue to perpetuate a "surplus," as appears to have been the case for the last few years, there is no assurance that it will since spot purchases, which currently dominate, provide no incentive for idle capacity. Presumably, over time individual firm and longer term supply arrangements (working in conjunction with storage and transportation arrangements) will

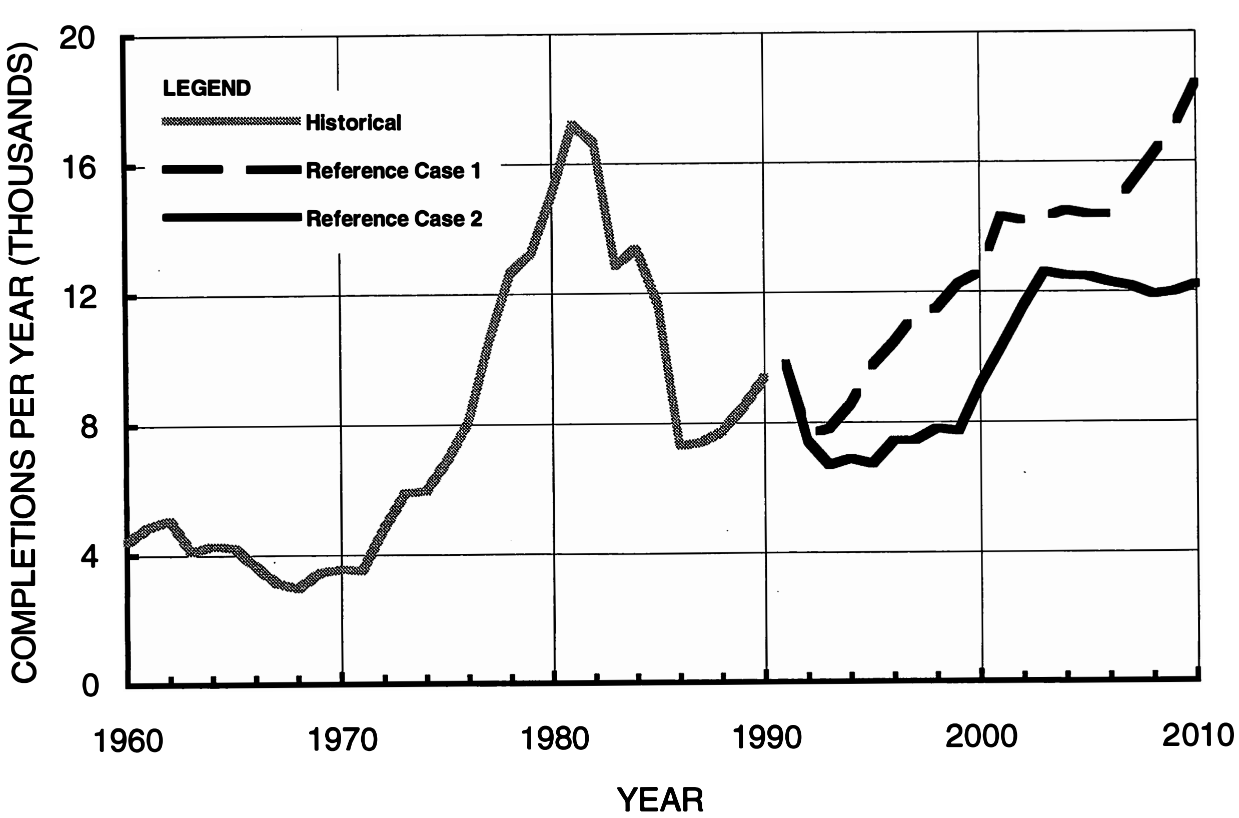


Figure 19. Gas Well Completions.

evolve, instead, to ensure that gas supply reliability is maintained.

Contract Diversity

The foregoing discussion of modeling results has centered on assessment of the view that supply can be maintained and that the business can "rebound" from today's low activity levels. Regulatory reform and contract diversity are essential elements in providing an appropriate business environment to ensure that it will.

Changes over the last decade that brought collapse of the old long-term contract structure along with continuing uncertainty in the natural gas regulatory and legislative arena have dramatically changed contracting practices. This has resulted in the emergence of a large spot market. While the spot market is likely to remain the preference for many participants, a continuing contract uneasiness prevents many other buyers and sellers from entering into medium- and long-term contracts. Although it would clearly be a mistake to try to return to the old highly regulated, rigid contract structure of the past, the uncertainty and instability that prevail today must be overcome.

The NPC believes it would promote growth of the free-market system to encourage the use of a wide variety of contract relationships between buyers and sellers. Individually negotiated, mutually beneficial contract relationships between buyers and sellers will help stabilize the market, increase demand, and provide more security on an as needed basis. Modern risk management tools can be used in conjunction with modern, innovative contracting approaches to protect buyers from uncertainty, encourage timely supply additions, and reduce general price volatility.

Both state and federal government policy and regulation can provide the right business environment so that such contracting practices will evolve as market signals and need dictate. Specifically, policy matters at the federal and state level should adopt principles that recognize the need for and merits of natural gas and the necessity to provide stable access to supply. They need to adopt practices that reestablish confidence of buyer and seller alike in the sanctity of contracts by reducing the exposure to retroactive changes and unreasonable "prudency" reviews. These subjects are dealt with in greater detail in Chapters Six and Ten of Volume I.

Import/Export Opportunities

It is the view of the NPC that the gas market will operate most efficiently based on free-market principles. This principle applies domestically and it should apply to import/export gas as well. The existing U.S./Canada free trade agreement is based on this principle.

In the near term, international natural gas trade can serve to strengthen domestic production capabilities by establishing new markets for gas sales. Although foreign gas supplies are expected to increase their market share in this country, natural gas export sales to Mexico, Japan, and Canada are also expected too. In the long term, additional competitively priced imports to the United States will add to the diversity of supply sources and the resources available to back U.S. demand growth.

The United States and many of its trading partners have been making serious efforts to liberalize their trade policies. The NPC supports continuation of this effort through such negotiations as the North American Free Trade Agreement (NAFTA) and other undertakings. However, it also finds that the NAFTA results as reported out fell short of this objective for the natural gas sector, due to several exceptions retained by Mexico for the energy sector. Over time, further effort by the United States is appropriate in support of natural gas exports to Mexico commensurate with standing rights for Mexican gas to be imported into the United States.

Much of the world's oil and gas business activity is U.S. based, historically rooted in domestic operations. Therefore, there is global value that can accrue to the U.S. economy in supporting competitive principles in the United States in exchange for equivalent undertakings by our trading partners. Reciprocal free trade efforts should seek competitively based, nondiscriminatory operating and ownership rights in all phases of the natural gas business. Specifically, failure of U.S. negotiators to challenge the Mexican constitutional limitations on oil and gas reserves development would work to the long-term disadvantage of increasing North American natural gas supply and consumption.

Fiscal Policy

Taxes and other government imposts are important factors in shaping the economics of natural gas exploration, development, and production. While resource costs and realized prices are the prime determinants of natural gas supply economics, fiscal systems can be used to both increase and decrease the economic cost of supplying natural gas to the U.S. market. While it would not be appropriate to seek preferential treatment, a constructive natural gas policy for the United States should incorporate a fiscal component that minimizes disincentives to finding new gas sources, developing new gas technologies, and fully exploiting known gas resources.

The U.S.-type tax system places a heavy tax burden on general savings and capital formation. In addition to generally applicable taxes such as income and property, natural gas incurs fiscal burden in the form of severance taxes, royalty, lease bonus payments, etc.

Of particular note is the alternative minimum tax (AMT) that acts as a disincentive against investment and contains several features that specifically penalize gas investments including ones made for environmental compliance.

In the depressed price environment that has prevailed in recent years, many natural gas producers who are in a loss position with regard to the regular income tax have found themselves faced with substantial AMT liabilities because they have remained active in the natural gas business.

One element of the U.S. tax policy that applies specifically to natural gas comes under Section 29 of the Internal Revenue Code. This income tax credit applies to nonconventional gas. Currently it is set at 53¢/MCF for tight gas and approximately 90¢/MCF for other types including coalbed methane. Especially for coalbed methane, and despite generally low gas prices, the Section 29 incentive has clearly worked to advance nonconventional technology and brought significant production into the market. The current incentive, as applied to new drilling, expires at the end of 1992. Opposition to extension centers on concerns of market distortion and fairness of such a large credit compared to conventional gas, which has limited price incentive and the inevitability that future conventional gas discoveries will generally be smaller or deeper and more expensive than in the past. Proponents of extension argue proven effectiveness as a stimulant to technology and the absence of entry barriers for industry participants.

Past Perceptions and the Need for Supply Education

Both industry and government share responsibility for the poor identity of natural gas. The NPC believes both must participate in an effort to correct public and consumer misunderstanding of natural gas supply potential and to establish an identity for natural gas that stands on its own merits.

This NPC study itself can serve as a tool in NPC participating member company, DOE, and possibly White House statements, and press releases and report distribution.

While no substitute for regulatory reform and customer-oriented contracting practices, there are informational and educational steps for industry and government to consider. Industry should intensify its efforts to increase public/consumer understanding through joint industry sponsored education programs. The recently formed Natural Gas Council is an example of the approach that can be taken and utilized at the general public as well as the major consumer level.

Additional steps the DOE should consider include a reexamination of its supply information base and distribution process to ensure that state commissions better understand supply dynamics, including recognition of the lead time needed to translate demand signals into new supplies. For example, the DOE could sponsor a conference on energy data and forecasting.

CHAPTER ONE

RESOURCE BASE COMPARISONS

INTRODUCTION

Even though natural gas has been produced in the lower-48 states for nearly 100 years, the remaining resource base is still very large. In fact, it is likely that we are only in the early stages of exploitation in terms of the total amount of the resource base to be ultimately recovered. Many portions of it are still virtually untapped.

Past and current misperceptions about the natural gas resource base would cause some to question these statements. Most of the misperceptions involve the definition of proved reserves and their role in future supplies.

Approximately 760 trillion cubic feet (TCF) of natural gas have already been produced in the lower-48 states as of January 1, 1991. This might seem like a large amount when compared to our current proved reserve level of 160 TCF. However, proved reserves are only a ready inventory of supply that can be delivered to the consumer in a relatively short time period. It is important to understand that there is a vast amount of recoverable resource beyond the proved reserve level, which can be found and developed when this inventory begins to run low.

This must also be remembered when considering the reserves-to-production ratio (R/P ratio). At current production levels of approximately 17 TCF per year, the R/P ratio is 9.4. This should not be interpreted to mean that gas supplies will be exhausted within the next decade. The R/P ratio is only an indicator that measures the relative size of the ready inventory of gas supply to the current production rate. As proved reserves are produced, exploration programs will discover additional supplies from the recoverable resource, which will be converted to proved reserves to maintain the inventory level. This will continue to happen as long as the marketplace provides the economic incentive for suppliers to invest their capital in the exploration for and development of new reserves.

One of the most important assumptions in this study is that technology advancements will continue to occur over time as they have in the past. Advancements in technology allow a greater portion of the in-place resource to be recovered by decreasing the cost of extraction or increasing the physical recoverability. Therefore estimates of the ultimately recoverable resource grow over time.

The relationship between resource potential and time is better shown in Figure 1-1. The results of NPC Reference Case 1 (the moderate energy growth scenario) are used in this figure to illustrate the changing magnitude of the vari-

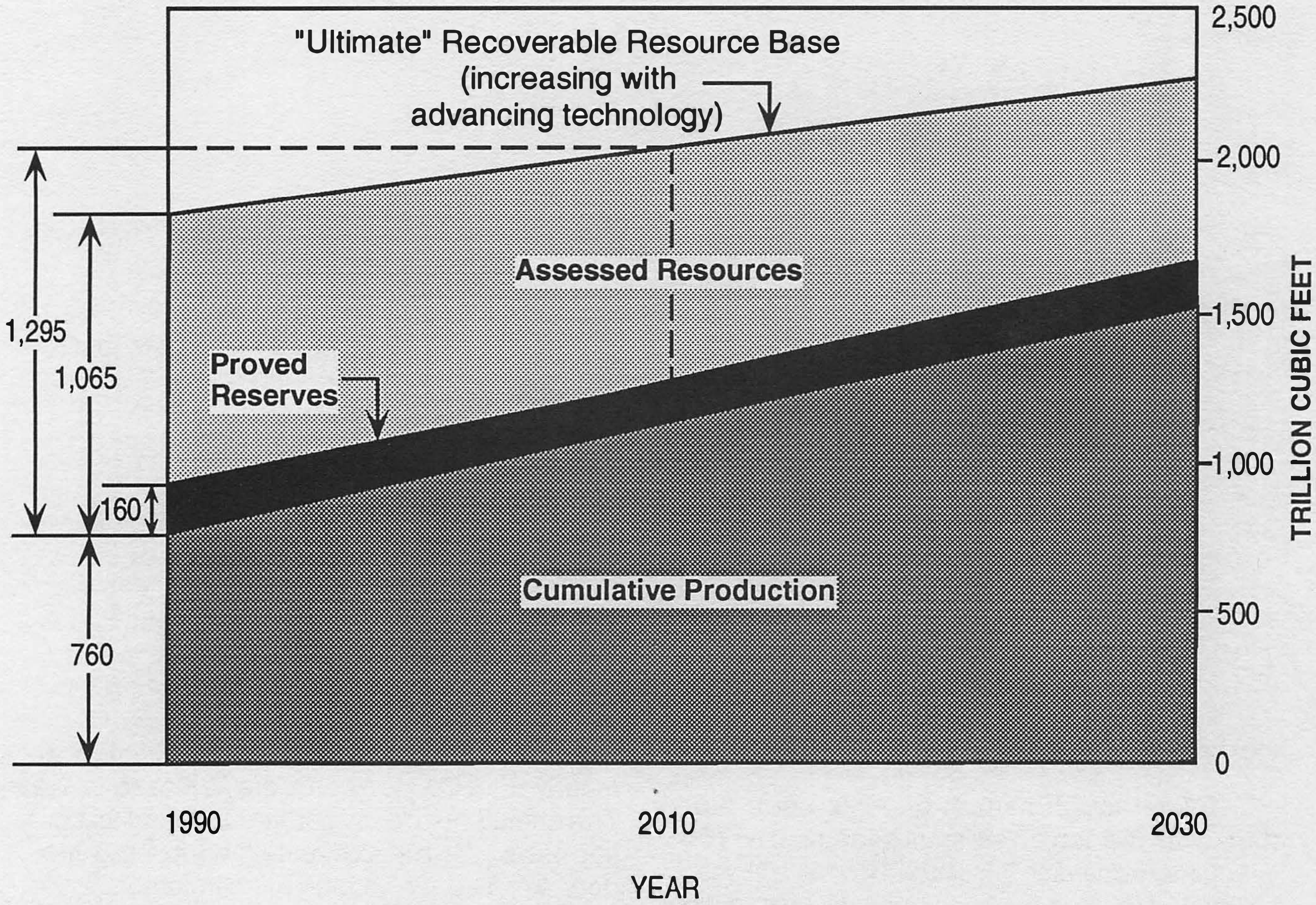


Figure 1-1. Resource Dynamics.

ous segments of the resource base and the relative contribution of advancing technology. The technically recoverable resource as estimated by the NPC is composed of proved reserves and "assessed resources," defined as that portion of the in-place resource that is estimated to be technically recoverable beyond the proved reserves level. Within each increment of time, proved reserves are produced and a portion of the assessed resource is discovered and developed, resulting in additions to proved reserves. At the same time, technology advancement causes an increase in the assessed resource base that nearly offsets the conversions to proved reserves. By 2010 the technically recoverable resource will be nearly as large as it is today.

The components that make up the total in-place gas resource are portrayed in Figure 1-2. The total in-place gas resource is the summation of gas already produced, technically recoverable resource, and the remaining in-place resource. The NPC recognizes that even with future, more advanced, technologies, some portion of the in-place resource will remain economically unrecoverable within the ultimate life span of the natural gas industry. The NPC has not attempted to estimate at what point this technical/economic limit might occur.

For the purposes of this study, the NPC has decided that the most appropriate assessment of the technically recoverable resource is one which is based on continued technology advancement through the year 2010, the final year of the study period. This estimate is 1,295 TCF, composed of 160 TCF of proved reserves and 1,135 TCF of assessed resources.

Figure 1-3 shows conceptually how increasing levels of available technology impact the technically recoverable resource estimate. Proved reserves, by definition, and a portion of the assessed resources can be recovered at current prices. An even greater quantity can be recovered with current technology; however, not all of it is currently economic (such as gas in smaller fields and deeper formations). An additional increment can be recovered with continued technology advancement through 2010, making up the NPC estimate of 1,295 TCF for the technically recoverable resource base. Lastly, there is an unquantified portion of the potential resource that will become available as technology advances beyond 2010 (such as gas in geopressured brines, gas hydrates, etc.), eventually reaching the ultimate technical/economic limit on recovery.

NPC RESOURCE BASE ASSESSMENT

The NPC lower-48 resource base assessment is the product of an extensive and comprehensive review and evaluation effort by representatives of corporate, government, trade, and academic organizations involved in the natural gas business. The resource base was subdivided into distinctly separate components so that an appropriate evaluation methodology could be used for each. These components are conventional new fields, reserve appreciation, coalbed methane, shale gas, and tight gas, each of which is further defined and described below. More detailed definitions and methodology descriptions are provided in subsequent sections of this chapter.

The NPC's estimate of the resource base in Table 1-1 represents the technically recoverable resource that is remaining as of January 1, 1991. Economics have not been explicitly factored into this estimate except to the extent that portions of the resources were excluded since they were poorly defined or unlikely to be significantly developed within the time frame of the study.

To aid in the comparison to other resource base estimates, two columns are provided in Table 1-1 representing different levels of technology advancement. The total in the first column, 1,065 TCF, is the NPC's assessment of the recoverable resource base using current technology. The second column was essentially derived through an extrapolation of the first column based on recognized trends in technology advancement and the effects on increasing recoveries. The resultant value of 1,295 TCF represents the portion of the in-place resource that can be recovered with 2010 technology.

For presentation purposes, the NPC estimates for each component of the resource

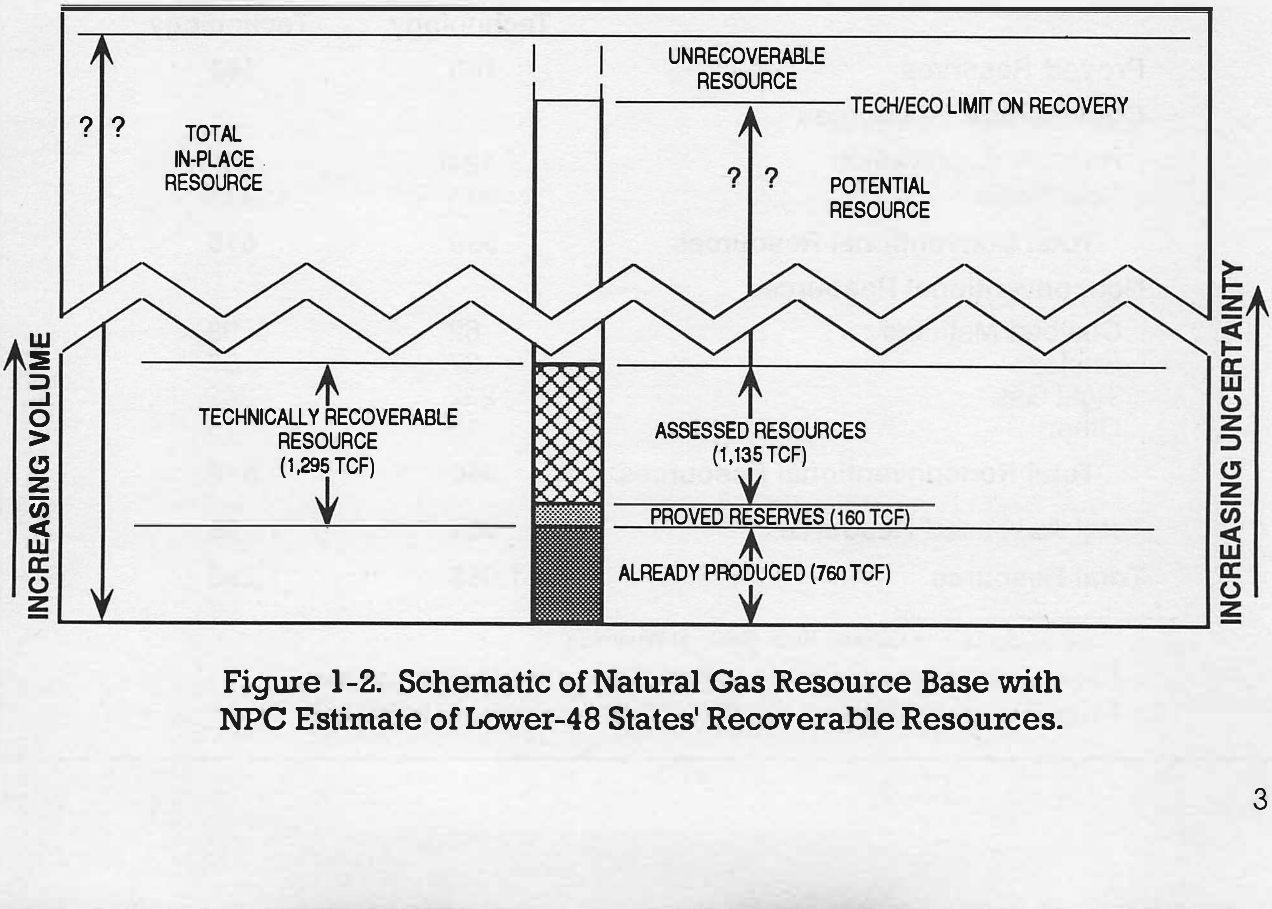

UNRECOVERABLE RESOURCE
TECH/ECO LIMIT ON RECOVERY
? ?
TOTAL IN-PLACE RESOURCE
? ?
POTENTIAL RESOURCE
INCREASING VOLUME
INCREASING UNCERTAINTY
TECHNICALLY RECOVERABLE RESOURCE (1,295 TCF)
ASSESSED RESOURCES (1,135 TCF)
PROVED RESERVES (160 TCF)
ALREADY PRODUCED (760 TCF)

Figure 1-2. Schematic of Natural Gas Resource Base with NPC Estimate of Lower-48 States' Recoverable Resources.

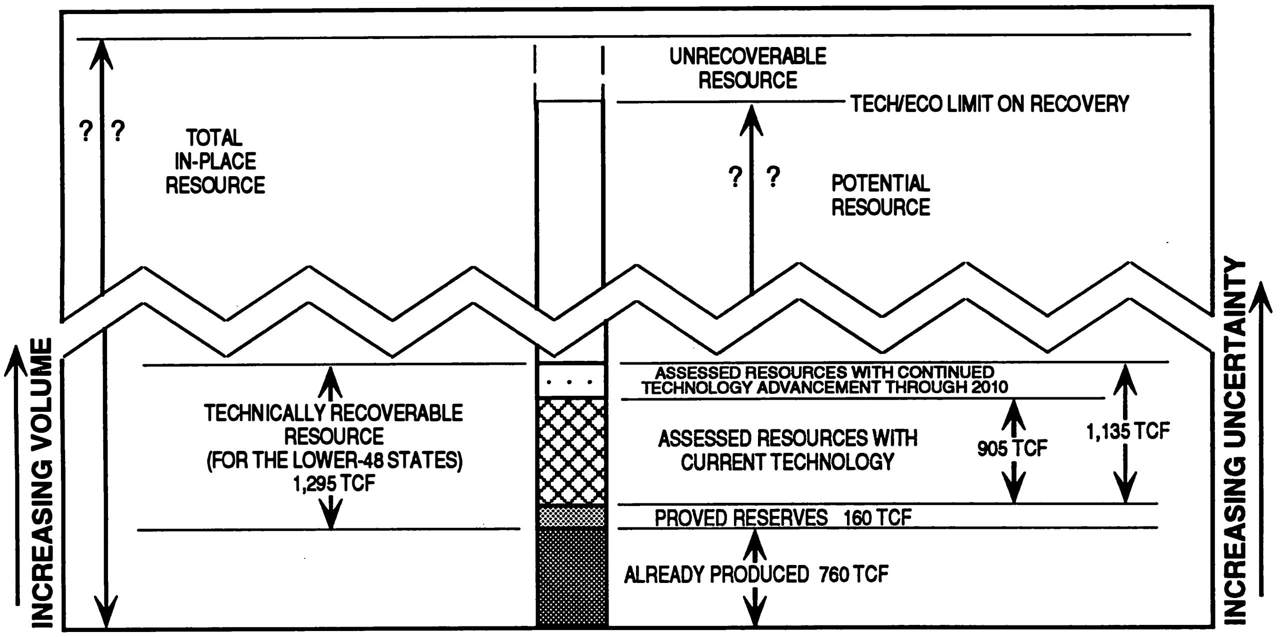

UNRECOVERABLE RESOURCE
TECH/ECO LIMIT ON RECOVERY
? ?
TOTAL IN-PLACE RESOURCE
? ?
POTENTIAL RESOURCE
INCREASING VOLUME
INCREASING UNCERTAINTY
TECHNICALLY RECOVERABLE RESOURCE (FOR THE LOWER-48 STATES) 1,295 TCF
ASSESSED RESOURCES WITH CONTINUED TECHNOLOGY ADVANCEMENT THROUGH 2010
ASSESSED RESOURCES WITH CURRENT TECHNOLOGY
905 TCF
1,135 TCF
PROVED RESERVES 160 TCF
ALREADY PRODUCED 760 TCF

Figure 1-3. Schematic of Natural Gas Resource Base.

TABLE 1-1

TECHNICALLY RECOVERABLE RESOURCE BASE IN THE LOWER-48 STATES AS OF JANUARY 1, 1991 (Trillion Cubic Feet)

	Current Technology	2010 Technology
Proved Reserves	**160**	**160**
Conventional Resources		
Reserve Appreciation	184†	203‡
New Fields	375	413
Total Conventional Resources	**559**	**616**
Nonconventional Resources		
Coalbed Methane	62	98
Shales	37	57
Tight Gas	232	349
Other*	15	15
Total Nonconventional Resources	**346**	**519**
Total Assessed Resource	**905**	**1,135**
Total Resource	**1,065**	**1,295**

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* Low BTU gas in the Green River Basin of Wyoming.

† Total reserve appreciation is 214 TCF; 30 TCF was transferred to tight gas.

‡ Total reserve appreciation is 236 TCF; 33 TCF was transferred to tight gas.

base have been separated into three major categories—proved reserves, conventional resources, and nonconventional resources. These categories are further described below.

Proved Reserves

The proved reserve total of 160 TCF for the lower-48 states was obtained from the Energy Information Administration's (EIA) annual report on U.S. oil and gas reserves. Proved reserves are the most certain of the resource base categories, because analysis of geological and engineering data from actual wells demonstrates with reasonable certainty that these volumes are recoverable in future years from known reservoirs under existing economic and operating conditions.

Conventional Resources

Conventional resources are the portion of the recoverable associated and high permeability, non-associated gas resource that can be extracted using traditional development practices. Typically, conventional resources have relatively high levels of recoverability but a large degree of uncertainty involving the in-place resource. The total conventional resource estimate for this study is 616 TCF.

The "Reserve Appreciation" component of conventional resources represents the growth of ultimate recovery (cumulative production plus proved reserves) from known fields which occurs over time. This growth can be due to extensions and more complete development of known pools and reservoirs as well as the exploration for and development of new pools and reservoirs within known fields. It may also occur as positive revisions resulting from infill drilling, improved technology such as horizontal drilling, enhanced recovery techniques, well workovers, recompletions, or improved economic conditions that extend the productive life of a well. It can also be attributed simply to changes in industry behavior and reserve booking practices. Reserve appreciation is relatively inexpensive compared to the other assessed resources since it is associated with known fields and therefore requires only small expenditures on infrastructure and exploration.

The NPC's assessment of 236 TCF for reserve appreciation is based on an extension of work previously done by the U.S. Geological Survey and the EIA. A large database was developed incorporating 22 years of EIA and American Petroleum Institute/American Gas Association history on published reserves by year of discovery. Based on these data, a growth curve was developed which included maturity (time since discovery) and activity levels (well completions) as variables in the determination of reserve growth levels. The latter variable was included since it was observed that reserve growth levels are significantly affected by the levels of activity in the industry. The NPC assessment included 33 TCF of low permeability resources that were later transferred to the "tight gas" component of nonconventional resources to maintain consistency within the category definitions. The resultant value for "reserve appreciation" in Table 1-1 is 203 TCF.

The "new fields" component of conventional resources is defined as resources estimated to exist outside of known fields on the basis of broad geological knowledge and theory. Also included are possible undiscovered pools within the areal confines of known fields to the extent that they occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic accumulations.

The NPC developed a resource estimate of 493 TCF for "new fields" using a consensus approach involving industry, government, and trade association representatives. Since many individual company resource estimates are proprietary, each participant discussed ranges of assessments for each region of the United States until a consensus was reached. Similar to the reserve appreciation component above, 80 TCF of low permeability resources were later transferred to the "tight gas" component of the nonconventional resources. The resultant value for "new fields" in Table 1-1 is 413 TCF.

Nonconventional Resources

Nonconventional resources include all other possible sources of gas, such as coalbed methane, shale gas, low permeability (tight) gas, gas in geopressured brines, and natural gas hydrates. However, the geopressured brines, gas hydrates, and portions of other nonconventional resources were not included in this assessment since their exploitation is considered unlikely within the time frame of the study.

The term "nonconventional" is used in this study only to be consistent with historical precedent. Much of the nonconventional resource has become just as viable and economic as the conventional resource and will continue to contribute a growing share of the supply mix over time. There is actually less uncertainty involved with the nonconventional resource compared to the undiscovered conventional resource in the sense that the locations of the nonconventional resource are relatively well known. It is characterized by very large in-place resources. However, the level of recoverability is much more uncertain due to higher dependence on the deployment of extraction technology.

The "coalbed methane" component of nonconventional resources is natural gas found in coal seams. Most drilling activity for coalbed methane has come in recent years, primarily in the San Juan Basin of Colorado and New Mexico and the Black Warrior Basin of Alabama. The motivating forces behind this activity are generally recognized as the nonconventional fuels tax credit and recent technology advances. The NPC estimate of 98 TCF is based on a review of known coal basins utilizing both proprietary and public domain data.

The "shale gas" component of nonconventional resources is methane that occurs in relatively low permeability shale formations. The principal known deposits are concentrated in the Appalachian, Illinois, and Michigan basins. The NPC estimate of 57 TCF is based upon well recoveries and resource in-place estimates made by Energy & Environmental Analysis and production data from Columbia Natural Resources.

The "tight gas" component of nonconventional resources is gas in low permeability formations (using the Federal Energy Regulatory Commission definition of 0.1 millidarcy or less). This resource typically produces at low rates and requires either relatively dense drilling, horizontal drilling, or hydraulic fracturing to increase the production rate to a level that will be economic.

The NPC estimated 235 TCF of "tight gas" resources based on a confidential survey of operators in known tight gas formations. For nonsurveyed areas, estimates were based upon 1980 NPC study results (*Unconventional Gas Sources*) and historical well recoveries. Additional tight gas resources were assessed within "New Fields" and "Reserve Appreciation" and added to this estimate to maintain consistency with the definitions for Table 1-1. Therefore the total "tight gas" resource is 349 TCF. As previously mentioned for other potential resources, the NPC estimate for tight gas excludes certain areas with tight gas potential which were unlikely to be significantly developed within the time frame of the NPC study.

Geographic Distribution

The geographic distribution of the NPC's technically recoverable resource estimate indicates that a significant shift in production between the regions of the lower-48 states must eventually occur in order to meet future natural gas demand.

The NPC separately assessed 17 regions within the lower-48 states for each category of gas. For illustration purposes, these regions have been combined into four general areas—West, Midcontinent, Gulf Coast, and East, as shown in Figure 1-4. The West area includes offshore Pacific resources, the Gulf Coast area includes offshore Gulf of Mexico resources, and the East area includes offshore Atlantic resources. The bar chart in Figure 1-5 compares cumulative production to the technically recoverable resource for each area.

Historically, nearly all production has come from the Midcontinent and Gulf Coast areas as shown with the solid bars. These areas consist primarily of conventional, high permeability resources as opposed to the West and East areas, which have a relatively large proportion of nonconventional resources. Due to previously available technology and economics, conventional resources in the United States have been developed and produced ahead of nonconventional resources. This is the reason for the greater historical activity levels, reserve development, and production in the Midcontinent and Gulf Coast areas compared to the rest of the United States.

As shown with the shaded and crosshatched bars, technically recoverable resource estimates (proved reserves plus assessed resources) for each area indicate that a

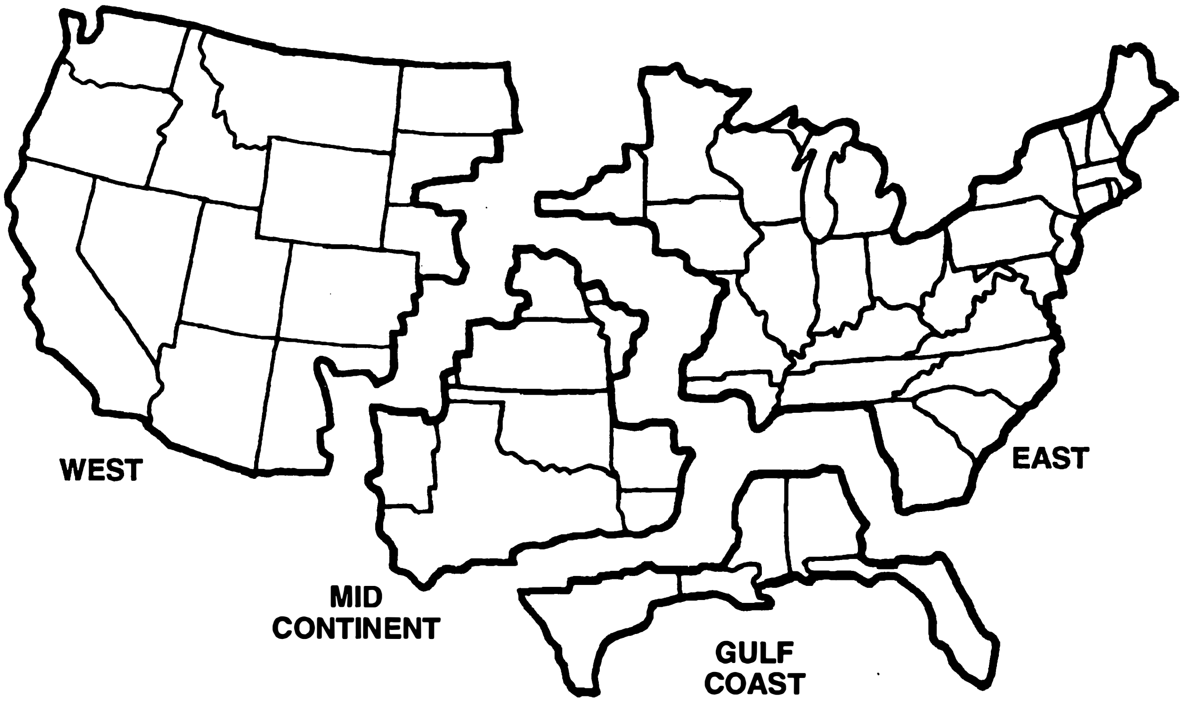

Figure 1-4. General Areas for Display of Resource Estimates.

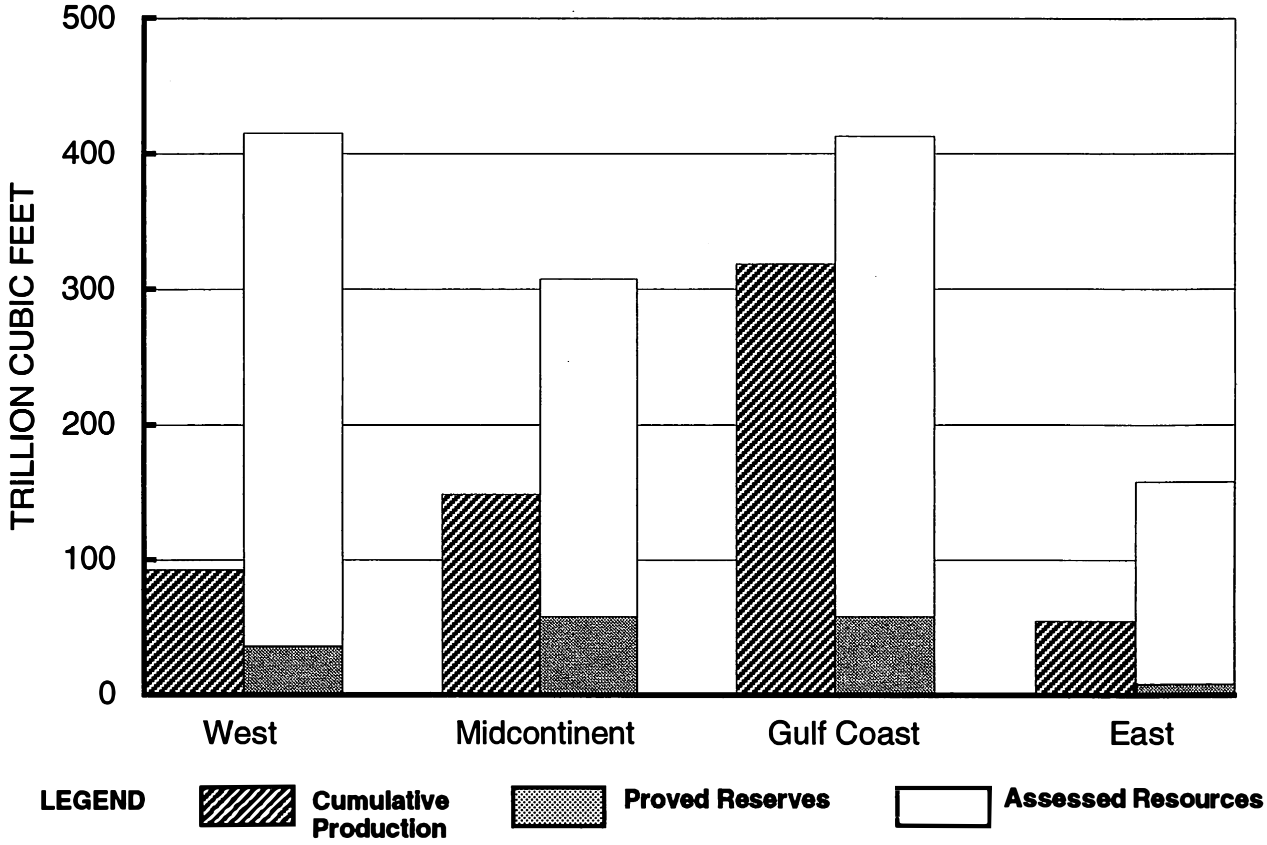

Figure 1-5. Comparison of Cumulative Production to Technically Recoverable Resources.

TABLE 1-2

TECHNICALLY RECOVERABLE RESOURCES IN THE LOWER-48 STATES BY AREA (Trillion Cubic Feet)

	West	Mid-continent	Gulf Coast	East	All Areas
Proved Reserves	**36**	**58**	**58**	**8**	**160**
Conventional Resources					
Reserve Appreciation	17	60	122	5	203
New Fields	76	89	197	50	413
Total Conventional Resources	**93**	**149**	**319**	**55**	**616**
Nonconventional Resources					
Coalbed Methane	72	0	10	15	98
Shales	0	0	0	57	57
Tight Gas	199	101	26	23	349
Other	15	0	0	0	15
Total Nonconventional Resources	**286**	**101**	**36**	**95**	**519**
Total Assessed Resource	**379**	**250**	**355**	**150**	**1,135**
Total Resource	**415**	**308**	**413**	**158**	**1,295**

redistribution of production and reserve additions should take place in the future as technology advances and economics improve. The results of the NPC's Reference Cases indicate that the West and East areas will contribute a greater portion of the lower-48 production mix by 2010.

Of the assessed resources, nonconventional gas makes up 72 percent in the West area (tight gas and coalbed methane) and 63 percent in the East area (primarily shale gas). Table 1-2 provides a breakdown of the assessed resources by area.

COMPARISON TO OTHER ESTIMATES

The NPC's estimate of the resource base is generally 10 to 20 percent larger than other industry estimates. The primary differences are typically in the reserve appreciation and tight gas categories. Table 1-3 provides a comparison of the NPC resource estimate (assuming continued technology advancement through 2010) to other recent studies by the Potential Gas Committee (PGC), Gas Research Institute (GRI), and the Energy Information Administration. The differences in estimation methodology and resource characterization must be understood in assessing the comparability of these estimates. An explanation of these differences is given below.

Potential Gas Committee

The PGC consists of volunteer members from all segments of the oil and gas industry, government agencies, and academic institutions who are concerned with natural gas resources. The Committee functions independently but with the guidance and assistance of the Potential Gas Agency of the Colorado School of Mines. The Potential Gas Agency is supported by the American Gas Association. PGC lower-48 estimates in Table 1-3 were taken from their 1990 report entitled *Potential Supply of Natural Gas in the United States.*

The PGC uses a team of estimators, each making an assessment of the volume of gas-bearing reservoir rock and its probable yield to arrive at an estimate of the recoverable resource base within a certain area of the country. These results are then aggregated to develop a total (the mean values were used in this comparison as opposed to the PGC's most likely values).

However, the impact of technology growth and economics on the PGC's estimate of the resource base is quite different from the NPC's. The PGC report states: "The recoverable resource base in the PGC estimate is that part of the resource that is susceptible to discovery and production during the life of the industry using current or foreseeable technology and favorable price/cost ratios." Essentially, the PGC estimates economically recoverable resources (although no specific price is assumed) whereas the NPC estimates technically recoverable resources. The PGC takes economics into account based on the estimator's subjective judgment of a minimum size and quality of resource accumulation. Also, the level of technology growth assumed by the PGC is quite modest compared to the NPC's assumptions.

The NPC's assessed resource estimate is larger than the PGC's estimate by 386 TCF (50 percent). A more relevant comparison would be to use the NPC's estimate based on current technology, which is approximately 160 TCF (20 percent) larger than the PGC's.

The PGC recognizes and reports potential resources as probable, possible, and speculative categories. Due to the nature of the coalbed methane resource, separate estimates are reported (in the same three categories).

TABLE 1-3

RECOVERABLE RESOURCES IN THE LOWER-48 STATES COMPARISON TO OTHER ESTIMATES (Trillion Cubic Feet)

	NPC 1992	PGC* 1990	GRI 1992	EIA/NES 1990
Proved Reserves	**160**	**160**	**160**	**160**
Conventional Resources				
Reserve Appreciation	203†	170	150	265
New Fields	413	491	394	327
Total Conventional Resources	**616**	**661**	**544**	**592**
Nonconventional Resources				
Coalbed Methane	98	88	110	90
Shales	57	—‡	123	30
Tight Gas	349	—‡	238	383
Other	15§	—	32¶	—
Total Nonconventional Resources	**519**	**88**	**503**	**503**
Total Assessed Resource	**1,135**	**749**	**1,047**	**1,095**
Total Resource	**1,295**	**909**	**1,207**	**1,255**
Adjust to 1/1/91	—	—	—	*35*
Total Adjusted Resource	**1,295**	**909**	**1,207**	**1,220**

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* Mean values used as opposed to "most likely" values.

† Total reserve appreciation is 236 TCF. 33 TCF of this total was transferred to the "tight gas" category.

‡ Potential Gas Committee estimates for shale and tight gas are included in the conventional resources.

§ Low BTU gas.

¶ Co-production gas.

The possible and speculative categories (excluding coalbed methane) have been combined and compared to the NPC's "new fields" estimate. The PGC's number appears larger, but this is due to the fact that the PGC does not explicitly separate low permeability or shale gas from high permeability resources. The PGC's estimates for shale gas and low permeability gas are included with totals for more conventional reservoirs, to the extent that (1) PGC estimators believe the gas to be recoverable by normal drilling and well stimulation and completion techniques, or foreseeable developments in technology, and (2) the potential resource occurs in geologic settings analogous to previous production.

The PGC's probable resource estimate (excluding coalbed methane) is comparable to the NPC's estimate of reserve appreciation. The coalbed methane resource has been separately assessed by the PGC and is comparable to the NPC estimate, although the mean values are not readily computed for the lower-48 states from the published PGC data. The reported value of 88 TCF in Table 1-3 is the sum of the lower-48 most likely values.

Gas Research Institute

The GRI develops resource base estimates for their annual projection of natural gas supply and demand. The estimates are based on statistical analyses of industry activity within the context of geological and engineering factors particular to a region and depth interval. The GRI estimates include the effects of advanced technologies on gas recoveries and costs, especially for the less conventional gas sources. As such, the GRI estimate is directly comparable to the NPC estimate.

GRI resource estimates in Table 1-3 have been taken from their publication entitled *The Long Term Trends in U.S. Gas Supply and Prices: 1992 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2010.* Individual resource categories in the GRI estimate have been broken out on a comparable basis to the NPC estimate. The NPC assessed resource estimate is 88 TCF (8 percent) larger than the GRI estimate, the difference being primarily in the reserve appreciation and tight gas assessments.

Energy Information Administration

The EIA conducted a study in 1990 to estimate U.S. recoverable hydrocarbon resources in support of the National Energy Strategy (NES). This study was based on a literature review and data analysis. The results of this study were published in a report entitled *The Domestic Oil and Gas Recoverable Resource Base: Supporting Analysis for the National Energy Strategy.*

The EIA estimates in the report are economically recoverable resources—of sufficient size and quality for their production to be commercially profitable by current technology under specific economic assumptions. However, in their Access and Advanced Technology Case, used for comparison in Table 1-3, advances in technology were assumed to lower costs sufficiently so that any volumes thought to be technically recoverable would also be economically recoverable. This case assumes continued technology advances through 2030 (compared to the NPC's assumption of advancement through 2010) and all access restrictions have been removed, allowing a better comparison to the NPC estimate.

The NPC's assessed resource estimate is approximately 70 TCF (7 percent) larger than the NES estimate. This difference could potentially be much larger using comparable technology levels. The primary difference in the two estimates as presented is in the "new fields" assessments.

CHAPTER TWO
CONVENTIONAL GAS

SUMMARY

The Conventional Gas Work Group assessed the size of the conventional gas resource base by component, reviewed industry cost experience and development practices, and determined the economic assumptions commensurate with past industry behavior to evaluate the range of future natural gas supply expectations.

The assessment of the resource base focused on two areas: the remaining undiscovered non-associated and associated/dissolved gas, and the expected future growth of proved reserves in existing fields or reserve appreciation. The evaluation of remaining undiscovered non-associated and associated/dissolved gas involved a review of publicly available assessments of the undiscovered resource base as well as discussions about the possible range of the estimate in each specific region of the United States. The resulting consensus of the study group is that an estimated total of 376 trillion cubic feet (TCF) of gas could be recovered from postulated gas in place without regard to economic criteria and using today's technology. Assuming that technology advances at its demonstrated historical rate, this resource would be 413 TCF.

The NPC study group that reviewed reserve appreciation conducted a detailed analysis of historical trends in reserves growth using 22 years of American Gas Association (AGA) and Energy Information Administration (EIA) data and developed a modification of an existing technique for estimating future growth. This technique assumes that the estimated ultimate recovery (cumulative production plus remaining proved reserves) of gas in existing fields will increase over time and that the rate of increase will be affected by the level of drilling activity since field discovery. The study group concluded that reserve appreciation is a demonstrated fact in history and that any assessment of a resource base should include the reserve appreciation resource. The reserve appreciation resource base for conventional gas is estimated to be 184 TCF under today's technology and 203 TCF under the advanced technology assumption.

Estimates of expected results of future exploration activity were developed by a consulting firm, Energy and Environmental Analysis, Inc. (EEA), who analyzed historical exploration results. The result of the analytical work was development of a mathematical basis for predicting future exploration results on a regional basis. The Conventional Gas Work Group reviewed this work and concluded that it would appropriately represent the expected future industry exploration program results.

The Conventional Gas Work Group also concluded that historical cost data published by the American Petroleum Institute (API) and obtained from Joint Association Surveys would provide an appropriate estimate of future industry costs. In areas where public data were limited or not available, estimates made by study group members were adopted.

The results of integrated supply and demand model simulations show that conventional gas will remain a significant contributor to the domestic supply of natural gas over the 20-year period of the NPC natural gas study. However, towards the end of the period, the conventional gas resource base reaches a level of maturity that results in conventional gas supplying a declining proportion of the overall domestic gas supply given the future price path. In NPC Reference Case 1, the moderate energy growth scenario, conventional gas is estimated to supply about 83 percent of domestic gas production in 1995 and decline to 72 percent by 2010. For NPC Reference Case 2, the low energy growth scenario, conventional gas is estimated to decline from 86 to 78 percent over the same time frame.

INTRODUCTION

The NPC determined that the Gas Research Institute's Hydrocarbon Supply Model (HSM) developed and maintained by EEA would be the forecasting model to be utilized for predicting supply, demand, and price for natural gas. An updated description of the model used in the NPC study is available from the NPC or EEA. The charter for the Conventional Gas Work Group was to review all aspects of how conventional gas was characterized in the HSM. This review was to include: an assessment on a regional basis of the amount of conventional gas remaining to be discovered; an estimate of the level of future changes to proved reserves in existing fields (hereinafter referred to as reserve appreciation); the rate at which both of these resources could be found by exploration drilling; the costs of exploration, development, and production of existing and future reserves; and the appropriate industry-representative economic parameters for use in simulating industry behavior.

CONVENTIONAL GAS WORK GROUP APPROACH

The work effort was divided into three distinct categories: undiscovered resources, reserve appreciation, and cost/economic assumptions. These three areas provided complete coverage of the charter for the group and allowed the assembly of a team of knowledgeable industry, government, and trade association representatives to focus on defined segments of the resource base.

Each of the three subgroups was asked to develop a process by which they could reach a consensus on their final work product and present that product to the Conventional Gas Work Group for review and comment. Each of the subgroups was also given the charge of working directly with the EEA consultants to develop a detailed understanding of the model itself and the input data requirements. The Conventional Gas Work Group in turn reviewed the recommendations from the subgroups, developed a consensus among the members, and passed their recommendations to the Source and Supply Task Group.

EXISTING PROVED RESERVES

The basic source of reserve information is the annual EIA report on U.S. oil and gas reserves. The information contained in this report is presented with detail shown on a state level, but the HSM is designed to segment the resource base into 13 onshore and 5 offshore geographic regions that for the most part do not follow state boundaries. Furthermore, each of the onshore regions is divided into four reservoir depth zones and each offshore region can have up to four water depths. Therefore, the EEA consultants utilized information from the EIA data base to appropriately disaggregate the proved reserve data into the various regions/depths of the HSM. Table 2-1 presents the U.S. lower-48 dry gas proved reserves as of year-end 1990, as contained in the HSM.

Proved reserves are the starting point for the HSM in terms of estimating the supply of gas. The production from proved reserves in the HSM is based upon estimates of capacity and decline curves for each region/depth. The estimates of capacities are based upon data obtained from the Natural Gas Supply Association survey of producers.

There are considerable public data available on production by state, field, reservoir, and/or well, depending upon the particular region in question. Analysis of this publicly available production information for wells and fields in each region/depth was utilized to develop decline curves for the HSM.

TABLE 2-1

U.S. LOWER-48 DRY GAS PROVED RESERVES YEAR-END 1990 (Billion Cubic Feet)

Region		Total
Appalachia	A	6,718
MAFLA Onshore*	B	3,296
Midwest	C	1,243
Arkla-E. Texas	D	11,658
So. Louisiana	E	8,171
Texas Gulf Coast	G	13,154
Williston	WL	1,485
Rockies Foreland	FR	10,599
San Juan Basin	SJB	15,624
Overthrust	OV	3,790
Midcontinent	JN	31,841
Permian	JS	14,420
Pacific	L	2,993
Subtotal Onshore		**124,992**
Norphlet	BO	4,780
West Florida		
Gulf of Mexico	EGO	28,626
Pacific Offshore	LO	1,646
Atlantic Offshore	AO	
Subtotal Offshore		**35,052**
Grand Total		**160,044**

* MAFLA — Mississippi, Alabama, and Florida.

RESERVE APPRECIATION

Physical Basis for Reserve Appreciation

The estimated ultimate recovery (EUR) of an oil or gas field is defined as cumulative production plus *proved* reserves. Data on EUR by year of field discovery have been published by the AGA and later by the EIA. It has been observed since the data were first published that the EUR for most oil and gas fields increases over time. Such reserve appreciation occurs as a result of reserve additions from field extensions and new reservoirs, and positive revisions resulting from infill drilling, improved technology, enhanced recovery techniques, well workovers, recompletions, and longer productive life of wells encouraged by higher prices. This reserve appreciation also is a reflection of industry behavior and reserve booking practices. The reserve appreciation resource is an estimate of those reserves that will be added over time to known fields. Nationally, the growth in estimated field sizes accounts for about two-thirds of annual additions to proved reserves. Fields that have been under production for decades are still undergoing significant growth. Gas fields discovered before 1968 accounted for 7.6 TCF of the 14.4 TCF total reserve additions in 1989.

Reserve appreciation is a function of how well the physical framework of the reservoir can be understood and utilized as a basis to target well completions. Increasingly sophisticated technologies, ranging from 3-D seismic, to cased-hole well logging, to horizontal drilling, and to computer visualization/simulation, have allowed progressively improved characterization of reservoirs and their inherent heterogeneities.

Recognition that different depositional systems have different styles of compartmentalization, depending on the rate of deposition, diagenesis, and structural history, has led to increasingly intense and effective scrutiny of reservoirs for their incremental recovery potential. In some cases, this potential has been slow to be recognized. However, the experience of the last 15 years, given the availability of vast amounts of new information, has yielded a far better understanding of both the mechanisms for, and the magnitude of, the natural gas reserve appreciation resource. This study has further quantified the size of that resource, after careful and complete review of previous estimates, and has found that significant opportunities remain for natural gas reserve appreciation in domestic fields.

The estimated ultimate recovery of natural gas in known fields have been shown to grow with continued field development toward or beyond the best then-current estimate of total hydrocarbon-in-place. This occurs both on a reservoir basis and for fields consisting of multiple reservoirs. Both improvements in economics and technology can add to reserves as an increasing fraction of the total in-place resource.

The Office of Technology Assessment in a 1985 report, *U.S. Natural Gas Availability, Gas*

Supply Through the Year 2000, cited five examples of sources of "new gas from old fields:"

- Lowering of abandonment pressure, which is typically tied to gas prices and the economic life of wells and surface equipment
- Infill drilling, which involves adding new wells to recover gas not in communication with existing wellbores
- Fracturing and acidizing, which can improve flow continuity between gas-bearing reservoir rock and the wellbore
- Well workovers, which improve the mechanical condition of the well or treat the reservoir to improve flow
- Extension of drilling into previously subeconomic portions of the field, which again is tied to prices and/or to improvements in extraction technology.

All of these activities have added new reserves in old fields, but it is predominantly infill drilling, extension drilling, and activities in existing wells such as re-completions and re-stimulation that can add reserves previously not physically accessible irrespective of price. These new reserves are often a product of the review of existing data that points to new opportunities for gas recovery.

The recovery of natural gas from fully delineated pools tends to be greater than was initially estimated because technology developments during the last three decades have had significant impact on how hydrocarbons are discovered, developed, and produced. The following developments are a few that have had a major impact on the growth of EUR.

Well Logging

The development of modern open hole logging tools such as Formation Electrical Resistivity Tools (Induction, Laterolog, etc.), Formation Porosity Tools (Density, Acoustical, Neutron, etc.), and the refinement of the mathematical techniques utilized to interpret log responses have greatly improved the industry's ability to identify hydrocarbon-bearing reservoirs in new fields or overlooked reservoirs in old fields. Additionally, these modern logging tools have made possible more accurate quantification of key reservoir parameters such as porosity, fluid saturations, and net pay. Equally important is the much more recent development of cased-hole logging tools such as pulsed-neutron logs, which have made it much easier to detect bypassed hydrocarbons in multi-reservoir fields. Recent development of techniques for obtaining information about the subsurface formations, using measurement while drilling, offer new opportunities for better analysis.

Well Stimulation

Of particular importance to improved recovery is the technique of hydraulic fracturing because it goes beyond the removal of near-wellbore formation damage. Hydraulic fracturing can create fractures that extend considerable distances into the reservoir from the wellbore. This results in a much higher effective permeability and correspondingly higher producing rates. This technology can rejuvenate and extend the economic life of older wells. In low permeability reservoirs, because deep-penetrating fractures increase a well's drainage radius, hydraulic fracturing has made it possible to achieve economically attractive production from natural gas accumulations previously considered uneconomic.

Methods of Reservoir Engineering Diagnosis

Developments in pressure transient testing methods have had significant impact on improving recovery. A comprehensive methodology has been developed to use pressure buildup and drawdown data from gas wells to predict the manner in which a well will produce over its life under varying operating conditions. The results of such well tests are being utilized to obtain more reliable information about rock, fluid, and well properties, to identify reservoir boundaries, to determine well spacing, pool development, and the need for well stimulation.

Significant developments in reservoir performance prediction methods have occurred in the science of reservoir simulation. Reservoir simulation, based on the method of finite differences, has found widespread application during the last two decades because high-speed computers have made it possible to model larger fields in a reasonably short time and at a reasonable cost. Reservoir simulation is now recognized by engineers and geologists as one of the best methods to evaluate alternative development and depletion plans, and to determine optimum producing rates, well spacing, and locations for infill wells.

Seismic Acquisition and Interpretation

Advances in seismic processing technology have improved subsurface imaging significantly over the past few years. The geoscientists' ability to resolve structures and stratigraphic changes at greater depths has increased confidence in deeper pool, extension, and infill drilling.

Very recent breakthroughs in three dimensional seismic acquisition and processing have established great potential for future field exploitation. The use of three dimensional seismic surveys on modern microcomputer workstations gives interpreters the ability to see details orders of magnitude better than before, especially the potential compartmentalization of reservoirs.

Vertical seismic profiles and other wellbore seismic tools provide extremely high resolution data in the proximity of the well. These data are very valuable for gas reservoirs since they enable delineation of the lateral extent of gas/water contacts.

Previous Estimates of Reserve Appreciation

Over the years, researchers have attempted to characterize the systematic nature of field growth. Since large numbers of fields are involved, most of the techniques have been statistical, centering on the estimation of annual or cumulative growth factors. As the age of fields increases, the annual growth factors would be expected to approach zero and the cumulative growth factors would be expected to approach an asymptote related to the original gas in place in a field.

The principles of field growth were developed for recoverable oil and were later applied to natural gas. J. R. Arrington evaluated the economics of recent exploration for the Carter Oil Company and needed factors to correct for the initial underestimation of sizes of new fields. He estimated the annual growth of a field using an underlying assumption that the amount of growth a field experiences in any one year is proportional to the size of the field and that the proportionality constant changes as the field ages.[1]

Arrington's measure of the degree of development was the age of the field in years from the date of discovery. This measure is readily available and represents the simplest index of all the various types of development that a field can undergo. Development activities include delineation and development drilling, water flooding, and producing oil or gas. He utilized data from Carter Oil from which he calculated the growth factors for oil fields. Arrington did not assume a functional form relating the annual growth factors to the age of the field.

R. G. Marsh used the same method as Arrington, and applied it to the published API and AGA series on estimated recoverable oil and gas by year of discovery.[2] The published estimates were as of year-end 1966, 1967, 1968, and 1969. Marsh was the first to estimate natural gas reserve growth and, according to his results, oil fields grew more than gas fields.

M. K. Hubbert, like Arrington, was interested in assessing the size of recent discoveries. His method differed from Arrington's method in that Hubbert assumed a functional form for the cumulative growth factors and estimated them directly from the API and AGA data.[3] He assumed that the volumes of unproved recoverable oil and gas in a field decayed exponentially with time. These growth factors were later utilized by Mast and Dingler in 1975 to estimate indicated and inferred reserves for the first U.S. Geological Survey (USGS) national assessment.[4]

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[1] J. R. Arrington, 1960, "Size of Crude Reserves is Key to Evaluating Exploration Programs," *Oil & Gas Journal*, vol. 58, no. 9, pp. 130-134.

[2] R. G. Marsh, 1971, "How much oil are we really finding?" *Oil & Gas Journal*, vol. 69, no. 14, pp. 100-104.

[3] M. K. Hubbert, 1974, "U. S. Energy Resources, a Review as of 1972, Part 1," in *A National Fuels and Energy Policy Study*: U.S. 93rd Congress, 2nd Session, Senate Committee on Interior and Insular Affairs, Committee Print, Serial No. 93-40 (92-75) 267 p.

[4] R. F. Mast and Janet Dingler, 1975, "Estimates of Inferred and Indicated Reserves for the United States by State," in *Geological Estimates of Undiscovered Oil and Resources in the United States*, U. S. Geological Survey Circular 725, 78 p.

In 1981, the USGS estimated future growth by the Arrington method, using API and AGA estimates of ultimate recovery by size of discovery.[5]

More recently, the USGS and Minerals Management Service published a revised set of estimates of inferred reserves for oil and gas fields discovered prior to 1987.[6] The Arrington method was applied to a selected set of API/AGA data to obtain a set of coefficients different from those published in USGS Circular 860,[7] but where oil and gas coefficients were based on the same set of data. Because API/AGA Bluebooks ceased publication with the 1979 edition, the factors utilized for estimating growth of pre-1987 fields did not reflect the significant expansion of the oil and gas industry activity that occurred in the early 1980s and its resulting impact on reserve appreciation.

The Potential Gas Committee (PGC) has developed estimates of probable reserves for the lower-48 states since 1966. These estimates of additional probable reserves in known fields corresponds roughly to inferred reserves as utilized by the USGS. The assessment procedure utilized by the PGC is a subjective volumetric yield technique. The PGC describes their estimates as representing the conventional potential natural gas resources expected to be recovered by future drilling under conditions of adequate economic incentives in terms of price/cost relationships, and current or foreseeable technology. Their estimates do not consider specific gas price forecasts.

The Bureau of Economic Geology (BEG) in Texas used a combined geology and reservoir engineering approach to estimate reserve appreciation for the U.S. Department of Energy.[8] A key component of this study was an estimate of the amount of gas in place in compartments of reservoirs that were not in contact with a wellbore. The study was based on the relationship of recovery to depositional systems gained from Texas experience with complex oil reservoirs. These results were then extrapolated nationally to natural gas reservoirs. The estimate of total reserve growth potential from the study was 288 TCF for the lower-48 states, onshore and offshore, associated and non-associated reservoirs.

The resulting estimates of remaining growth for the above methods of calculation are summarized in Table 2-2. In four selected cases, the actual growth through 1989 is also shown. (In the calculation of actual growth, it

TABLE 2-2

ESTIMATES OF EXPECTED GAS RESERVE GROWTH IN THE U.S. LOWER-48

Estimator	Vintage of Fields	Reserves Appreciation (TCF)	Actual Growth to 1989 (TCF)
Marsh (1971)	pre-1970 fields	70	141
Hubbert	pre-1972 fields	193	138
Mast & Dingler	pre-1973 fields	166	139
Root	pre-1979 fields	132	148
DOI (1987)	pre-1987 fields	96	
DOE/BEG	pre-1987 fields	288	
EIA	pre-1988 fields	265	
PGC	pre-1989 fields	170	
GRI (1992)	pre-1991 fields	150	

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[5] David H. Root, *Historical Growth Estimates of Oil and Gas Field Size*, U. S. Geological Survey, Reston, Virginia.

[6] Department of the Interior, 1989, *Estimates of Undiscovered Conventional Oil and Gas Resources in the United States – A Part of the Nation's Energy Endowment*, U. S. Geological Survey/Minerals Management Service, 51 p.

[7] G. L. Dolton et al, 1981, *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*, U. S. Geological Survey Circular 860, p.83-87.

[8] R. J. Finley et al, 1988, *An Assessment of the Natural Gas Resource Base of the United States*, The University at Austin, Bureau of Economic Geology Report of Investigations No. 179, 69 p.

was necessary to make allowance for the difference between the API/AGA data series and the EIA data series.) It is significant to compare the actual growth with the original estimate for these four cases and to recognize that most, if not all, of the predicted reserve appreciation had already occurred by 1989. This lends credence to the concept of reserve appreciation and to the importance of including it in any assessment of the resource base.

NPC Analytical Approach

Previously published estimates for the growth of existing proved reserves have ranged from a mainly subjective basis to forecasts based upon a statistical analysis of past history. It was concluded that any forecast of reserve growth should have a sound technical basis, which relied upon what has actually transpired in the industry regarding reserve bookings.

Estimates of natural gas ultimate recovery data were available from two sources: the Oil and Gas Integrated Field File, maintained by the Energy Information Administration, and *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada*, published by API/AGA.

The Oil and Gas Integrated Field File is the EIA data base file that provides an estimate of the crude oil and natural gas proved reserves, annual production, cumulative production, and ultimate recovery for most U.S. oil and gas fields. As of June 1991, the file contained field level estimates for each of the 13 years from 1977 to 1989 for about 46,000 oil and/or gas fields. Several sources of data were utilized in the compilation of the estimates. The prime source of information on proved reserves is the Form EIA-23 "Annual Survey of Domestic Oil and Gas Reserves." Production information was derived from several sources, the most common being the Dwight's Energy data lease and well files and the Dwight's Energy Petroleum Data System. In addition, the API/AGA data files and the EIA Field Code Master Field List were utilized as sources. For those fields where information from the Form EIA-23 was incomplete or missing, estimates were derived using average values common to the producing area.

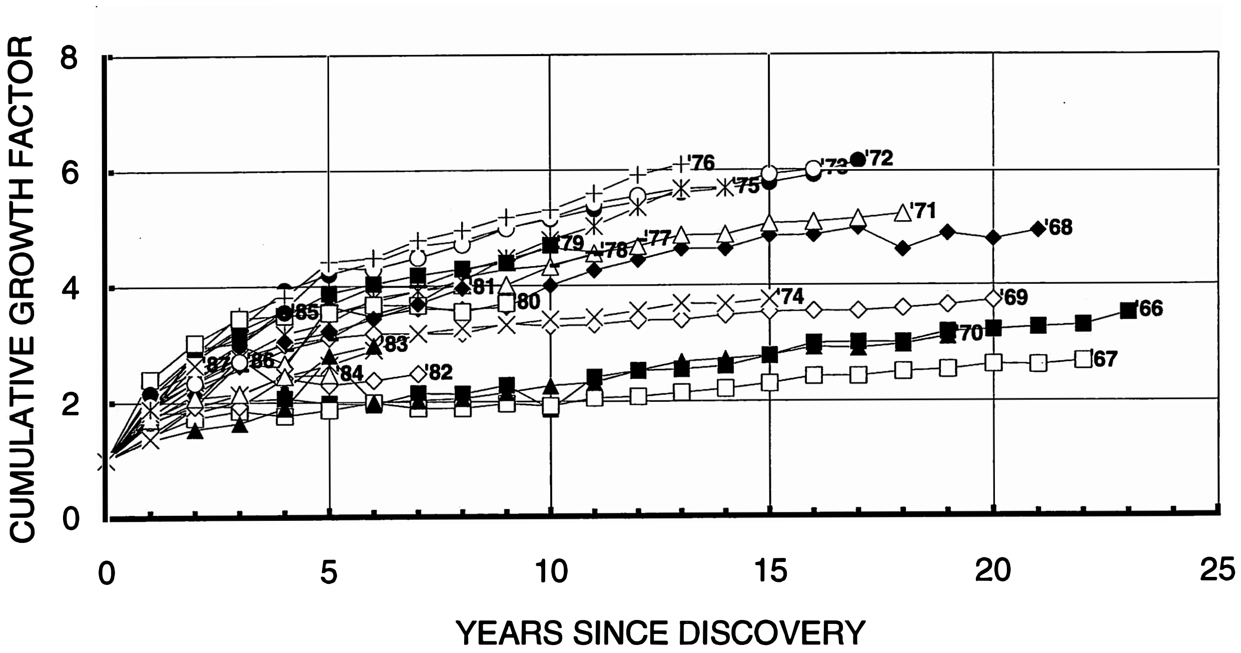
Both the EIA and AGA data sets include data for non-associated and associated/dissolved gas. However, a critical review of the AGA data on associated/dissolved gas led to the conclusion that only the EIA data set for this gas should be utilized. Although the two sets of data were developed by different approaches and contain somewhat different results in the overlap years, the data were adapted in such a manner as to provide a 22-year history of reserve growth. The resulting data set demonstrates clearly that the reserves initially booked by companies will grow substantially over time and indeed that booked reserves from fields discovered more than 50 years ago are still increasing, although at a low rate of growth.

The growth patterns for fields discovered between 1966 and 1988 for the NPC non-associated gas data base are shown in Figure 2-1.

Previous analysis of historical reserve growth using published reserves by year of discovery has assumed that the booked reserves will grow only as a function of time regardless of the level of industry activity. However, the level of industry activity during the 22-year history available covers a broad spectrum of activity, from the "boom" days of the early 80s to the "bust" days of the late 1980s. Therefore, it was concluded that reserve growth should be tied to both maturity and activity level. The statistic deemed most appropriate as representative of industry activity is well completions.

Development of a growth curve based both upon time and drilling activity not only assumes that reserves will continue to grow with time, but that they will grow at varying rates according to the level of industry activity. Since the current EIA data base represents reporting by the vast majority of industry companies, it was concluded that the growth curve was well founded and valid.

Since the growth curve is tied to the initial booking of discovered reserves, some concern exists as to the nature of industry reserve booking practices over the 22-year time period. Indeed there have been varying pressures influencing reserve estimates during the period, such as gas sales contracts accounting standards and Securities and Exchange Commission regulations. However, reserve estimates tend to be self-correcting since an estimate that



SOURCE: 1966-1976: "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada," AGA, API, Canadian Petroleum Association.
1977-1989: "Oil and Gas Integrated Field File," EIA.

Figure 2-1. Growth Factors for Non-Associated Gas.

is too high must some day be removed as a negative revision. Therefore, the booking practices in industry have been reasonably stable over an extended period. This has been particularly true since the implementation of Reserve Recognition Accounting by the Securities and Exchange Commission in 1976.

Oil and gas well completions were obtained from DeGolyer and McNaughton's *Twentieth Century Petroleum Statistics* for 1920 through 1969. Completions for 1970 through 1989 come from the source file for "Table 5.2. Oil and Gas Exploratory and Development Wells" contained in the *Monthly Energy Review*, Energy Information Administration, Office of Energy Markets and End Use.

An explicit functional form was selected that depended on both time and cumulative wells drilled. The addition of cumulative drilling allowed the construction of a reserve appreciation function with a clearly defined limiting asymptotic value that naturally explained the increases in the rate of reserve appreciation per year in the 1977 to 1989 period compared to the 1967 to 1976 period. Figure 2-2 shows examples of the NPC non-associated reserve appreciation model for 1922 discoveries under different drilling assumptions. Although the analytical work utilized a data series based on wet gas data, it was assumed that the final results represented dry gas volumes.

The lower growth factor curve is for an assumption that 2,000 gas wells are drilled every year, which was roughly the historical rate during the early life of a 1922 discovery. The heavy middle curve represents the model prediction with historical drilling patterns. Note the abrupt change in slope in the mid-1970s (about 50 years since discovery). This occurred when the annual rate of gas drilling accelerated rapidly. The top curve represents the shape of the growth curve for 1922 fields if 20,000 gas wells per year had been drilled. The growth factors in this curve increase at a higher rate, but eventually approach the same asymptotic limit (6.6) as the historical and projected completion curve. The lower curve would eventually reach the same asymptotic value of 6.6, but would take a longer period of time to do so. Other curves for historical and projected drilling will be a little different for each discovery year.

An additional feature of the work to develop an equation characterizing the appreciation of proved reserves was that non-associated and associated/dissolved gas were analyzed separately. The functional form of the equations was identical, but the associated/dissolved equation relied upon the number of oil wells drilled since discovery rather than gas wells.

Results of NPC Analysis

The results of the analytical work on reserve appreciation can be viewed by comparing the predicted growth curve for an example discovery year to the actual growth patterns for fields discovered between 1966 and 1988 for the NPC non-associated gas data base, as shown in Figure 2-3. The cumulative growth factor is calculated by dividing the ultimate recovery in any year by the ultimate recovery estimate in the year of discovery. The actual growth factor is already over six for some discovery years (1976 and 1972) and under three for other discovery years (1970 and 1967). The heavy black line is an example growth curve calculated from the NPC reserve appreciation equation. The curves calculated directly from the data show a fairly wide spread around the example curve; however, the example growth curve does seem to reflect a rough average behavior of the growth curves directly calculated from the NPC data base.

Using the same NPC data base, both the reserve appreciation methods that use functional forms (Hubbert and EIA) that depend on field age and those that utilized other statistical methods not dependent on a specific functional form (Arrington, Marsh, and USGS) would probably end up with a curve that was roughly similar to the example curve shown in Figure 2-3.

One of the key results to gain from Figure 2-3 is not the spread of the actual curves around the example curve, but rather the rate of growth of the curves compared to the predicted curve. The ultimate growth factor is important for new discoveries, but the rate of growth for existing proved reserves is the more important part of the prediction, which determines the size of the reserve appreciation resource. Figure 2-3 shows that the predicted rates of growth starting some five years after discovery are quite similar for the discovery year data that is plotted.

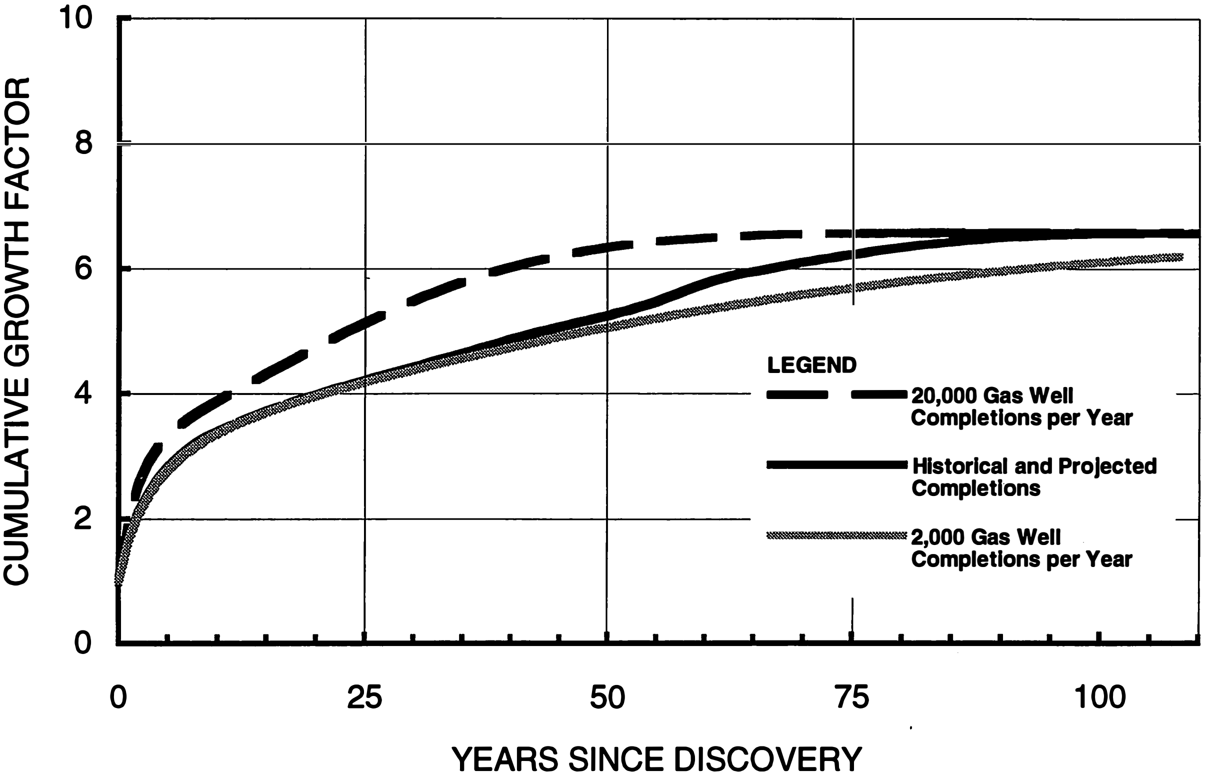
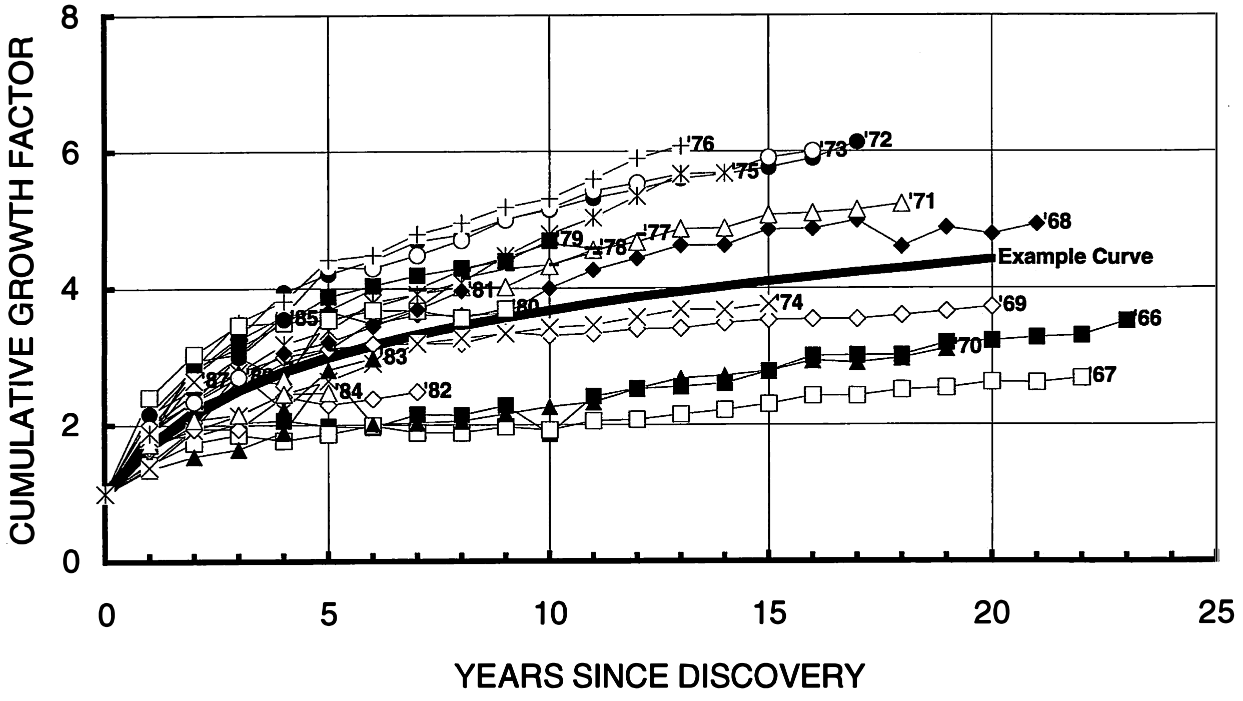


Figure 2-2. Growth Curve for 1992 Discoveries of Non-Associated Gas.



SOURCE: 1966-1976: "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada," AGA, API, Candian Petroleum Association.

Figure 2-3. Growth Factors for Non-Associated Gas.

Table 2-3 shows the predicted reserve appreciation for the years 2010 and 2030 with various drilling assumptions. In addition, the reserve appreciation of non-associated gas after 4,000,000 cumulative gas wells are drilled is estimated to be roughly 216 TCF. This is almost the limit of reserve appreciation in the model. Similarly after 14,000,000 cumulative oil wells have been drilled the associated/dissolved gas reserve appreciation will reach 20 TCF for a total reserve appreciation of 236 TCF. Most of this is proved by the year 2030.

The reserve appreciation resource was allocated to the HSM regions/depths in proportion to the distribution of ultimate recovery by discovery year in each area. Table 2-4 shows the results of that allocation and represents the actual data utilized as input to the HSM for the NPC gas study.

Table 2-5 provides a further breakdown of the total gas reserve appreciation by high permeability non-associated, tight non-associated gas in old plays, and associated/dissolved gas. This table includes tight gas in old plays in the total reserve appreciation resource because such growth is in the historical data base. For the purposes of total resource base reporting in this study, this volume of resource is reported under nonconventional tight gas.

Reserve Appreciation in the Hydrocarbon Supply Model

Within the Hydrocarbon Supply Model, the process of reserve appreciation is represented by field "growth curves," which define what portion of a field's ultimate reserves may be proved in the year of initial field discovery and in subsequent years. The curves have two functions in the HSM. The first is to regulate how quickly reserves are proved and, thus, how quickly natural gas reserves may be produced. The second function of the field growth variable is to help determine when development wells are drilled. These curves represent the maximum rate at which the reserve appreciation resource can be exploited. The actual rate within the HSM may be slower depending upon product prices, capital constraints, or other limiting factors.

For the purposes of projecting the rate at which reserves appreciate in the HSM, it is first necessary to estimate the length of the period over which a newly discovered field will grow from the initially booked value to its ultimate size. Table 2-6 shows the assumed time period for each field size class in the HSM. Note that it was assumed that the largest fields would be fully appreciated in 30 years, while the smallest would be fully developed by the initial and only well.

The growth factor curves for new fields utilized in the HSM were developed using the results of a USGS analysis of historical reserves information. These results were used to estimate the average annual growth rate for the largest fields, which would be fully appreciated in 30 years. The rate of growth for smaller fields with a shorter appreciation life was scaled down proportionally. Table 2-7 shows the annual fraction of the estimated ultimate reserves that is available to be developed and booked in each year after discovery. An exception to the data in Table 2-7 is that it is assumed that deep onshore fields are proved up more slowly than shallower fields due to the high cost of deep wells. This effect was simulated by adding one (10-15,000 feet) or two years (below 15,000 feet) to the time needed to prove deep onshore fields.

The preceding discussion concerned the patterns of growth for new fields whose discovery the model simulates. The model must also deal with continued growth of existing fields found before the model simulation begins. For purposes of the NPC study, existing fields were defined as those discovered through the end of

TABLE 2-3

PREDICTED RESERVE APPRECIATION
U.S. LOWER-48

		Change From 1990	
Non-Associated Gas (using combined EIA/AGA data)		**Ultimate Recovery (Billion Cubic Feet)**	**Percentage**
Ultimate Recovery at Year-end 1990, BCF	694,334		
Year 2010 with 314,500 additional Gas Wells		135,664	19.5
Year 2030 with 771,720 additional Gas Wells		201,674	29.0
After 4,000,000 Cumulative Gas Wells		216,090	31.1
		Change From 1990	
Associated/Dissolved Gas (using EIA data)		**Ultimate Recovery (Billion Cubic Feet)**	**Percentage**
Ultimate Recovery at Year-end 1990, BCF	223,588		
Year 2010 with 421,422 additional Oil Wells		14,450	6.5
Year 2030 with 1,005,862 additional Oil Wells		18,810	8.4
After 14,000,000 Cumulative Oil Wells		20,224	9.0
		Change From 1990	
Total Non-Associated and Associated/Dissolved Gas		**Ultimate Recovery (Billion Cubic Feet)**	**Percentage**
Ultimate Recovery at Year-end 1990, BCF	917,922		
Year 2010 with additional Gas and Oil Wells as above		150,114	16.4
Year 2030 with additional Gas and Oil Wells as above		220,314	24.0
After 4,000,000 Cumulative Gas Wells and 14,000,000 Cumulative Oil Wells		236,314	25.7

TABLE 2-4

1-1-91 RESERVE APPRECIATION RESOURCE NON-ASSOCIATED, ASSOCIATED/DISSOLVED, AND TIGHT GAS IN OLD PLAYS

(Billion Cubic Feet)

Region		0-5,000'	5-10,000'	10-15,000'	>15,000'	Total
Appalachia	A	1,249	393			1,642
MAFLA Onshore	B	499	1,590	2,098	942	5,129
Midwest	C	1,045	593	1,283		2,921
Arkla-E. Texas	D	3,630	7,375	3,723	90	14,818
So. Louisiana	E	0	3,083	8,390	10,062	21,535
Texas Gulf Coast	G	3,798	19,985	7,426	5,033	36,242
Williston	WL	526	294	332	0	1,152
Rockies Foreland	FR	2,578	6,099	1,730	1,166	11,573
San Juan Basin	SJB	4,319	3,328	0	0	7,647
Overthrust	OV	32	2,083	4,065	2,146	8,326
Midcontinent	JN	10,511	9,098	7,691	6,338	33,638
Permian	JS	4,184	6,315	4,436	8,144	23,079
Pacific	L	925	1,168	374	671	3,138
Subtotal Onshore		**33,296**	**61,404**	**41,548**	**34,592**	**170,840**
		Subregion				
		1	**2**	**3**	**4**	**Total**
Norphlet	BO	3,555				3,555
West Florida						0
Gulf of Mexico	EGO	32,842	23,456	4,861	0	61,159
Pacific Offshore	LO	711		54		765
Atlantic Offshore	AO					0
Subtotal Offshore		**37,108**	**23,456**	**4,915**	**0**	**65,479**
Grand Total						**236,319**

Note: Values are recoverable hydrocarbons as of 12-31-90; Subregions for BO, EGO are <40m, 40-200m, 200-1000m, and >1000m water depth; LO is 0-200m and 200-2000m; AO and West Florida have no defined water depth.

1989. The Hydrocarbon Supply Model was modified so the quantity and timing of pre-1990 field appreciation could conform to the results of the analytical work described in the Alaska section of Chapter Four.

The reserve appreciation potential was allocated among regions and depth intervals by applying the growth curves to individual fields in EEA's *Oil and Gas Field Database* and then scaling the results to achieve a total of 216 TCF of non-associated gas and 20 TCF of associated/dissolved gas. The non-associated gas was further broken down between high permeability and tight gas, based on the ratio of historical discoveries in each region, with some upward adjustment to the tight gas values to account for the expectation that future appreciation would be increasingly more tight.

The Hydrocarbon Supply Model was then calibrated to predict a similar quantity of reserve appreciation from pre-1990 fields in each region as would be expected from the NPC growth curves. Once this initial calibration was obtained for a specific activity (drilling) scenario, the HSM was programmed to automatically adjust the growth curve parameters for changing activity levels.

UNDISCOVERED RESOURCES

Terminology

The resource terminology in this report is that utilized by the oil and natural gas industry and the resource estimation community. Though a detailed listing of common industry definitions is not included, several definitions that are essential to the proper understanding of the information in this report are presented.[9]

- ***Resources.*** Known or postulated concentrations of naturally occurring liquid or gaseous hydrocarbons in the earth's crust that are now or which at some future time may be developed as sources of energy.
- ***Conventional resources.*** Resources included in this category are crude oil, natural gas, and natural gas liquids that exist in reservoirs in a fluid state amenable to extraction employed in traditional development practices. They occur as discrete accumulations. They do not include resources occurring within extremely viscous and intractable heavy oil deposits, tar deposits, oil shales, coalbed gas, gas in geopressured shales and brines, or gas hydrates. Gas from low-permeability "tight" sandstone and fractured shale reservoirs having in situ permeability to gas of less than 0.1 millidarcy are not included as conventional resources.
- ***Undiscovered conventional resources.*** Conventional resources estimated to exist, on the basis of broad geologic knowledge

TABLE 2-5

1-1-91 RESERVE APPRECIATION RESOURCE (Billion Cubic Feet)

Region		Associated Gas	High Perm NA Gas	Tight Gas In Old Plays	Total NA Gas	Total All Gas
Appalachia	A	627	1,015	0	1,015	1,642
MAFLA Onshore	B	545	4,583	0	4,583	5,128
Midwest	C	774	2,146	0	2,146	2,920
Arkla-E. Texas	D	2,264	7,908	4,646	12,554	14,818
So. Louisiana	E	813	20,722	0	20,722	21,535
Texas Gulf Coast	G	1,697	28,494	6,051	34,545	36,242
Williston	WL	579	271	303	574	1,153
Rockies Foreland	FR	1,039	2,504	8,027	10,531	11,570
San Juan Basin	SJB	209	318	7,120	7,438	7,647
Overthrust	OV	466	7,861	0	7,861	8,327
Midcontinent	JN	1,658	29,061	2,918	31,979	33,637
Permian	JS	3,757	14,913	4,408	19,321	23,078
Pacific	L	438	2,700	0	2,700	3,138
Subtotal Onshore		**14,866**	**122,496**	**33,473**	**155,969**	**170,835**
Norphlet	BO	0	3,555		3,555	3,555
West Florida						0
Gulf of Mexico	EGO	4,917	56,242		56,242	61,159
Pacific Offshore	LO	441	324		324	765
Atlantic Offshore	AO					0
Subtotal Offshore		**5,358**	**60,121**		**60,121**	**65,479**
Grand Total		**20,224**	**182,617**	**33,473**	**216,090**	**236,314**

Note: Assumes Advanced Technology.

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[9] These definitions were adapted from Mast et al, 1989, *Estimates of Undiscovered Conventional Oil and Gas Resources in the United States — A Part of the Nation's Energy Endowment*, Department of the Interior, USGS/MMS Special Publication, 44 p.

TABLE 2-6

NUMBER OF YEARS TO FULLY PROVE RESERVES IN A FIELD

Field Size Class	Average Size		Years
	MMBOE	BCF	
#1	.004	.02	1
#2	.008	.05	1
#3	.017	.10	1
#4	.034	.19	1
#5	.067	.38	1
#6	.134	.76	2
#7	.268	1.53	3
#8	.537	3.06	3
#9	1.07	6.12	4
#10	2.15	12.20	6
#11	5.3	24.4	7
#12	8.6	48.9	10
#13	17.2	97.7	13
#14	34.3	195.4	16
#15	68.7	391.4	21
#16	137.0	790.0	28
#17	274.0	1564.0	30
#18	549.0	3129.0	30
#19	1097.0	6255.0	30
#20	2196.0	12516.0	30

and theory, outside of known fields. Also included are resources from undiscovered pools within the areal confines of known fields to the extent that they occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions. For the purposes of this study, undiscovered conventional resources are a portion of the total resource base. Conventional resources are those recoverable using current recovery technology and efficiency but without reference to economic viability. These accumulations are considered to be of sufficient size and quality to be amenable to conventional recovery technology.

- ***Oil-equivalent gas.*** Gas volume that is expressed in terms of its energy equivalent in barrels of oil (BOE). One BOE equals 5,650 cubic feet of gas.
- ***Field.*** A single pool or multiple pools of hydrocarbons grouped on, or related to, a single structural or stratigraphic feature.
- ***Prospect.*** A geologic feature having the potential for trapping and accumulating hydrocarbons.
- ***Play.*** A group of geologically related known accumulations and/or undiscovered accumulations or prospects generally having similar hydrocarbon sources, reservoirs, traps, and geologic histories.
- ***Risked (unconditional) estimates.*** Estimated quantities of the volumes of oil or natural gas that may exist in an area, including the possibility that the area is devoid of oil or natural gas are risked (unconditional) estimates. Estimates presented in this report are of this nature. For this study, the estimated conventional resource values were utilized in the model as certain quantities (occurrence probability of 1.0), and the sensitivity of the model results to higher and lower resource estimates was evaluated without quantifying the occurrence probabilities.

Undiscovered Resources in the Hydrocarbon Supply Model

As a first step in the process of simulating industry behavior, the HSM uses resource base estimates, exploratory finding rates, drilling costs, and well production profiles to describe the operational nature of the exploration and production activities of both oil and gas. This approach captures the complexity of the process and allows the distinction between exploratory and economic success.

The central element in the supply modeling procedure is the estimate and distribution of the undiscovered gas resource available for exploration and subsequent development. The conventional undiscovered resource includes resources in undiscovered fields in both known and speculative plays. Known plays are those in which discoveries have been made. Speculative plays usually have a strong conceptual basis but no actual discoveries, and include areas that have very little seismic coverage or drilling data.

The HSM divides the lower-48 states into 13 onshore and 5 offshore regions, as shown in

Figure 2-4. Onshore, each region is divided into 4 well-depth zones—0 to 5,000 feet, 5,000 to 10,000 feet, 10,000 to 15,000 feet, and greater than 15,000 feet below sea level. Each offshore region is described in up to four cells differentiated by water depths. Each region and depth is described with its own unique exploration finding rate and field size distribution, which in turn defines the resource estimate.

The undiscovered conventional resource in the model is uniquely described for each cell (region and depth) by an exploration finding rate for each field size class. Within each cell, there are 20 field size classes ranging from about 4,000 BOE to greater than 2 billion BOE. Each size class is twice the size of the next smaller class. When available, historical drilling and production data from a number of sources are utilized to define the characteristics (largest field, number and rank of fields, shape of the distribution, etc.) of the field size distributions and finding rates. In frontier areas, the field size distributions are developed from geologic analogies.

The exploration process in an area rapidly increases geologic "knowledge" by condemning some parts of an area as nonprospective and identifying others as having high potential. During the early exploration of an area, many of the very large fields are

TABLE 2-7

PORTION OF FIELD PROVED EACH YEAR

Year	Field Size Class											
	#1-5	#6	#7-8	#9	#10	#11	#12	#13	#14	#15	#16	#17-20
1	1.0	.545	.404	.346	.301	.291	.280	.273	.267	.267	.254	.253
2		.455	.337	.289	.251	.243	.232	.228	.223	.223	.212	.211
3			.260	.223	.194	.188	.180	.176	.172	.172	.163	.163
4				.142	.124	.120	.115	.112	.110	.110	.104	.104
5					.080	.074	.074	.072	.071	.069	.067	.067
6					.050	.048	.048	.046	.045	.044	.043	.043
7						.032	.031	.030	.030	.029	.028	.028
8							.019	.018	.018	.017	.017	.017
9							.012	.012	.012	.011	.011	.011
10							.009	.009	.008	.008	.008	.008
11								.009	.008	.008	.008	.008
12								.008	.007	.007	.007	.007
13								.008	.007	.007	.007	.007
14									.007	.007	.007	.007
15									.007	.007	.007	.007
16									.006	.006	.006	.006
17										.006	.006	.006
18										.006	.006	.006
19										.005	.005	.005
20										.005	.005	.005
21										.005	.005	.005
22											.004	.004
23											.004	.004
24											.004	.004
25											.003	.003
26											.003	.003
27											.003	.003
28												.002
29												.002
30												.001

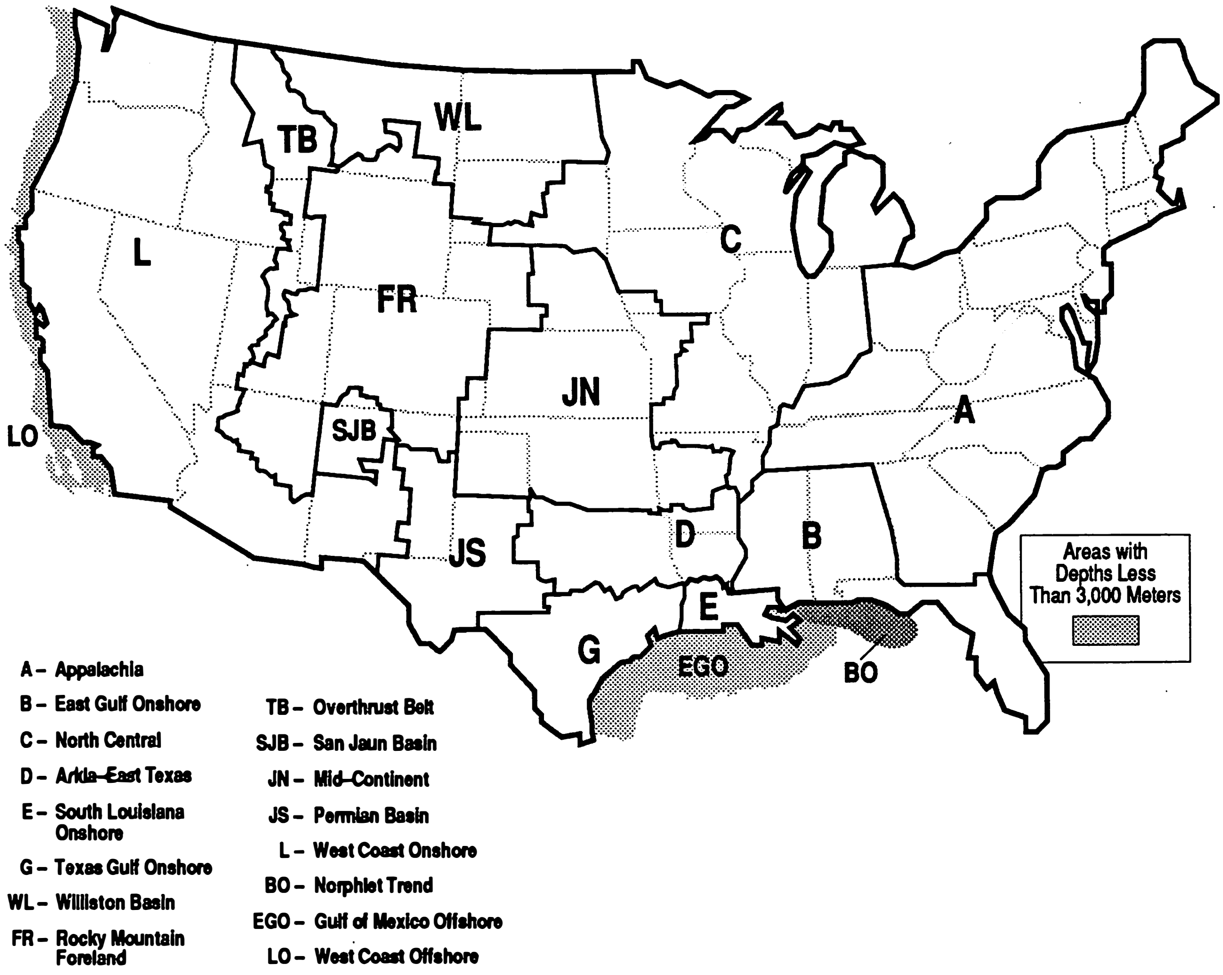

Figure 2-4. Hydrocarbon Supply Model Regions.

found simply because they have the highest probability of being encountered by virtue of their areal extent. As exploratory drilling progresses, it tends to be concentrated in known productive areas where smaller fields are targeted, thus leading to an increase in the number of fields discovered per unit of exploration activity. However, the number of fields of a given size per unit of activity decreases with time.

The Arps-Roberts equation was developed in 1958 to describe the phenomenon that a decreasing number of fields of a given size will be found per unit of exploration and yields an exponential decline in the rate at which all field size classes are found. However, historical data indicate that while this may be true for large fields, small to medium fields are found in greater numbers than predicted by Arps-Roberts. To adequately model the number of small fields found per unit of activity, the HSM employs a modified Arps-Roberts find rate equation called the double-exponential equation. This formulation adds a term to the Arps-Roberts equation to account for the concentration over time of drilling in known areas, targeting of smaller fields, and the learning curve from exploratory drilling.

Although gas is the focus of this study, the HSM simulates the exploration process for total hydrocarbons. Because oil and gas usually occur in similar geologic settings, their exploration, development, and production histories are necessarily intertwined. The model explores for hydrocarbons and once they are found, allocates them to oil and non-associated gas. The user-specified relative occurrence of gas to oil for each region and depth interval forms the basis for a split of discovered hydrocarbons between oil and gas. Associated and dissolved gas and natural gas liquids are determined from ratios applied to the discovered oil and non-associated gas volumes.

The model makes a further distinction between high and low permeability gas. Low permeability gas is generally defined as that gas occurring in formations with a permeability of less than 0.1 millidarcy. The historical record includes many instances of fields being exploited that are, under this definition, low permeability gas. Thus, undiscovered low permeability fields in these areas are described in the finding rate equations and field size distributions developed from the analysis of the historical record. Consequently, the amount of non-associated gas discovered by the model is split between high permeability and low permeability gas once exploration has been done. Other accumulations of low permeability gas that have no production history are represented elsewhere in the model.

The HSM exploration process predicts the number of fields of each size class (in each depth interval) found by an increment of exploratory well drilling. Each of the field sizes is described for development purposes by the number of wells required for full development, the costs for wells and facilities, and the rate at which the ultimate size of the field will be booked as proved reserves. The HSM books the reserves of the smallest fields in one year and progressively uses longer booking schedules for larger field sizes, with the largest fields scheduled over 30 years, as described in the section entitled "Reserve Appreciation in the Hydrocarbon Supply Model," found earlier in this chapter.

Once the results of an exploratory program are determined, an economic analysis of each of the field sizes using all of the aforementioned parameters is utilized to determine which of the fields are economic for development. The overall economics of the exploration program are then evaluated to determine if they provide an acceptably attractive investment opportunity and, if not, the exploration program is deferred.

After a field is "discovered," the model simulates the process by which reserves are developed in the field over time. The number of wells required for field development is largely predicated on field area and volume. The largest fields have the highest recoveries per well but still require the most wells for full development. Historical data on number of wells drilled in fields of a specific size class, average recovery per well, and cost components are utilized to model drilling requirements for fields in each region and depth interval.

In the model, gas fields are treated differently than oil fields in that, once production capacity is installed, production does not necessarily proceed at the maximum sustainable rate. Because of this, what would normally be treated as a production profile for oil is referred to as a deliverability (potential production) profile for gas. These profiles are part of the data that determine the revenues a producer can expect from field development. In brief, a deliverability profile is generated for each well in a block of reserves proved in each year after the field is discovered. This produces a series of production-from-reserves curves for each year after discovery. The profiles of reserves blocks are then summed to a field total. Thus, the annual field production, cumulative field production, and cumulative reserve additions can be modeled for each field.

NPC Assessment of Undiscovered Resources

The assessment of the size of the undiscovered resource was done by a consensus approach, initially involving a small core group of industry, government, and association representatives. This core group first developed a working understanding of the HSM, including not only how the model uses the resource base but also what criteria define the resource base that the model uses. Each member then discussed various aspects of the undiscovered resource base—field sizes and distribution, regional definition of the United States, reservoir depth onshore, water depth offshore, etc.

Although each participant brought an estimate of the resource base to the discussion based on a variety of assumptions and methods, open discussion of the details of each was not possible since several of these estimates are proprietary. Consequently, the group discussed ranges of assessments and through this discussion reached a consensus as to the approximate size of the undiscovered resource in each region of the model. Following the groups' consensus of the resource base in each region, the resource base in the model was reviewed and revisions recommended. Feedback and comments from the entire Conventional Gas Work Group were obtained and incorporated, resulting in a consensus assessment of the undiscovered resource.

The consensus assessment for the undiscovered resource in each region/depth, using current technology, is detailed in Table 2-8. These data form the basis for describing the entire undiscovered conventional resource that is input to the HSM. Note that Table 2-8 lists the resource in million BOE and includes the various components of the resource, i.e., oil, associated and dissolved gas, high permeability non-associated gas, tight non-associated gas in old plays, and natural gas liquids. Table 2-9 details the total gas resource that is contained in Table 2-8. Tables 2-10, 2-11, and 2-12 document the gas portion of the resource base by type: associated and dissolved gas, conventional non-associated gas, and tight non-associated gas in old plays, respectively.

Although the tight gas resource in old plays is estimated using the finding rate equations, this resource is really part of the noncon-

TABLE 2-8

TOTAL UNDISCOVERED CONVENTIONAL RESOURCE CURRENT TECHNOLOGY (INCLUDES TIGHT GAS IN OLD PLAYS) (Million Barrels of Oil Equivalent)

Region		**0-5,000'**	**5-10,000'**	**10-15,000'**	**>15,000'**	**Total**
Appalachia	A	1,267	2,004	959	402	4,632
MAFLA Onshore	B	344	168	2,334	1,075	3,921
Midwest	C	1,110	1,502	551	0	3,163
Arkla-E. Texas	D	1,513	2,795	1,413	279	6,000
So. Louisiana	E	0	190	699	2,594	3,483
Texas Gulf Coast	G	639	3,840	4,168	1,674	10,321
Williston	WL	395	906	338	0	1,639
Rockies Foreland	FR	1,448	5,658	2,910	3,230	13,246
San Juan Basin	SJB	362	680	0	0	1,042
Overthrust	OV	105	1,330	1,129	960	3,524
Midcontinent	JN	2,011	4,026	2,835	4,319	13,191
Permian	JS	1,539	2,447	1,423	2,704	8,113
Pacific	L	743	2,731	1,722	1,237	6,433
Subtotal Onshore		**11,476**	**28,277**	**20,481**	**18,474**	**78,708**
				Subregion		
		1	**2**	**3**	**4**	**Total**
Norphlet	BO	2,106	0	0	0	2,106
West Florida						540
Gulf of Mexico	EGO	6,070	5,545	4,991	11,556	28,162
Pacific Offshore	LO	2,630		9,563		12,193
Atlantic Offshore	AO					3,552
Subtotal Offshore						**46,553**
Grand Total						**125,261**

Note: Values are recoverable hydrocarbons as of 12-31-90; Subregions for BO, EGO are <40m, 40-200m, 200-1000m, and >1000m water depth; LO is 0-200m and 200-2000m; AO and West Florida have no defined water depth.

TABLE 2-9

TOTAL UNDISCOVERED GAS RESOURCE
CURRENT TECHNOLOGY
(INCLUDES TIGHT GAS IN OLD PLAYS)
(Billion Cubic Feet)

Region		0-5,000'	5-10,000'	10-15,000'	>15,000'	Total
Appalachia	A	6,216	10,288	4,926	2,159	23,589
MAFLA Onshore	B	854	357	5,468	4,229	10,908
Midwest	C	2,157	3,900	2,423	0	8,480
Arkla-E. Texas	D	3,843	7,198	6,165	1,317	18,523
So. Louisiana	E	0	557	2,319	12,319	15,195
Texas Gulf Coast	G	2,503	16,312	19,050	8,176	46,041
Williston	WL	946	1,199	447	0	2,592
Rockies Foreland	FR	3,577	16,449	12,221	16,351	48,598
San Juan Basin	SJB	1,170	1,981	0	0	3,151
Overthrust	OV	300	3,791	3,748	4,370	12,209
Midcontinent	JN	4,819	12,416	11,659	21,885	50,779
Permian	JS	3,586	6,202	4,598	12,328	26,714
Pacific	L	1,446	6,727	5,099	4,258	17,530
Subtotal Onshore		**31,417**	**87,377**	**78,123**	**87,392**	**284,309**
				Subregion		
		1	**2**	**3**	**4**	**Total**
Norphlet	BO	11,388				11,388
West Florida						2,590
Gulf of Mexico	EGO	25,311	23,122	15,722	36,402	100,557
Pacific Offshore	LO	2,807		10,204		13,011
Atlantic Offshore	AO					17,013
Subtotal Offshore						**144,559**
Grand Total						**428,868**

Note: Values are recoverable hydrocarbons as of 12-31-90; Subregions for BO, EGO are <40m, 40-200m, 200-1000m, and >1000m water depth; LO is 0-200m and 200-2000m; AO and West Florida have no defined water depth.

ventional tight gas resource. Therefore, the volumes detailed in Table 2-12 are listed again in Chapter Three as tight gas.

Comparison of NPC Assessment and Assessments by Others

All resource assessments by their nature begin from reasonably well-known quantities and facts, but proceed toward increasingly less well-known quantities and information. It is, therefore, useful to compare the NPC assessment of undiscovered resource volumetric estimates with other recent resource assessments and the methodologies by which they were developed.

Government, academic, and industry institutions have undertaken natural gas resource estimates in recent years. Work completed by the Department of Energy, Energy Information Administration, U.S. Geological Survey, Minerals Management Service, Gas Research Institute, and the Potential Gas Committee are featured in this review. In addition to these published assessments, industry producers also estimate natural gas resource potential in the productive and potentially productive geologic basins of the United States. Inasmuch as the methods, results, and actual portion of the resource base studied differ with every assessment, it is important to recognize the context in which assessment totals

TABLE 2-10

UNDISCOVERED ASSOCIATED AND DISSOLVED GAS RESOURCE CURRENT TECHNOLOGY

(Billion Cubic Feet)

Region		**0-5,000'**	**5-10,000'**	**10-15,000'**	**>15,000'**	**Total**
Appalachia	A	98	78	37	0	213
MAFLA Onshore	B	82	49	705	36	872
Midwest	C	1,145	1,162	36	0	2,343
Arkla-E. Texas	D	989	1,926	170	0	3,085
So. Louisiana	E	0	106	329	0	435
Texas Gulf Coast	G	318	1,306	726	0	2,350
Williston	WL	174	522	195	0	891
Rockies Foreland	FR	645	2,129	438	0	3,212
San Juan Basin	SJB	300	676	0	0	976
Overthrust	OV	48	612	87	0	747
Midcontinent	JN	1,925	2,754	776	0	5,455
Permian	JS	1,130	1,739	705	0	3,574
Pacific	L	283	1,023	604	384	2,294
Subtotal Onshore		**7,137**	**14,082**	**4,808**	**420**	**26,447**
				Subregion		
		1	**2**	**3**	**4**	**Total**
Norphlet	BO	0				0
West Florida						79
Gulf of Mexico	EGO	2,126	1,942	3,311	7,667	15,046
Pacific Offshore	LO	1,471		5,347		6,818
Atlantic Offshore	AO					516
Subtotal Offshore						**22,459**
Grand Total						**48,906**

Note: Values are recoverable hydrocarbons as of 12-31-90; Subregions for BO, EGO are <40m, 40-200m, 200-1000m, and >1000m water depth; LO is 0-200m and 200-2000m; AO and West Florida have no defined water depth.

are offered. The following discussion examines key factors and assumptions attributable to the individual resource assessments in Table 2-13 and compares significant elements of each to the NPC analysis.

DOE/1988

In May 1988, the Department of Energy released a study of natural gas resources entitled *An Assessment of the Natural Gas Resource Base of the United States.* The document revealed that a national panel of natural gas analysts estimated technically recoverable resources (including proved reserves) at 1,059 TCF in the lower-48 states, using current technology. Of that volume, onshore undiscovered conventional resources were estimated to be 219 TCF, while offshore resources were 134 TCF. Compared to the NPC estimates for current technology, the 1988 DOE onshore assessment is 5 percent smaller, while the offshore value is lower by 8 percent.

The purpose of the DOE study was to explore the underlying assumptions involved in the resource estimates available to the Review Panel, to normalize the application of the assumptions to all resource estimates, and to then form a consensus on resources estimated for categories of gas including undiscovered resources, inferred reserves, gas in lower permeability formations, coalbed methane, and shale gas. In addition, economic assumptions were studied in order to evaluate recovery of resources given wellhead prices of less than $3.00 per thousand cubic feet (MCF) and recovery of resources at wellhead prices of $3.00 to $5.00 per MCF (1987$).

The NPC and DOE methods of arriving at an estimate for conventional resources were similar in that resource assessments from a variety of sources including government and industry were documented, discussed, and examined for critical assumptions. A consensus process followed resulting in an estimate that reflected a range of analytical approaches.

EIA/1990

In an effort to support issues relevant to the development of a National Energy Strategy, the Energy Information Administration conducted a literature search and review to determine likely natural gas resources available to the nation and reported the results in a document entitled *The Domestic Oil and Gas Recoverable Resource Base: Supporting Analysis for the National Energy Strategy*. In the study, a reference scenario was expanded by assuming future access to federal lands for hydrocarbon exploration, by assuming advances in exploration and development technologies, and by considering the two enhancements (access to federal land and improved technology) together. Table 2-13 reflects the EIA scenario with access to federal lands and technology improvements. Certainly within the context of the NPC assessment, access to potential acreage in the lower-48 states was

TABLE 2-11

UNDISCOVERED CONVENTIONAL NON-ASSOCIATED GAS RESOURCE CURRENT TECHNOLOGY

(Billion Cubic Feet)

Region		**0-5,000'**	**5-10,000'**	**10-15,000'**	**>15,000'**	**Total**
Appalachia	A	3,807	9,135	4,889	2,159	19,990
MAFLA Onshore	B	772	308	4,763	4,193	10,036
Midwest	C	1,012	2,738	2,387	0	6,137
Arkla-E. Texas	D	2,283	3,427	4,463	1,054	11,227
So. Louisiana	E	0	451	1,990	12,319	14,760
Texas Gulf Coast	G	2,154	9,566	17,306	7,522	36,548
Williston	WL	386	677	252	0	1,315
Rockies Foreland	FR	1,173	5,728	4,713	7,358	18,972
San Juan Basin	SJB	348	522	0	0	870
Overthrust	OV	252	3,179	3,661	4,370	11,462
Midcontinent	JN	2,605	8,116	9,795	16,414	36,930
Permian	JS	1,824	3,347	3,309	12,328	20,808
Pacific	L	1,163	5,704	4,495	3,874	15,236
Subtotal Onshore		**17,779**	**52,898**	**62,023**	**71,591**	**204,291**
				Subregion		
		1	**2**	**3**	**4**	**Total**
Norphlet	BO	11,388				11,388
West Florida						2,511
Gulf of Mexico	EGO	23,185	21,180	12,411	28,735	85,511
Pacific Offshore	LO	1,336		4,857		6,193
Atlantic Offshore	AO					16,497
Subtotal Offshore						**122,100**
Grand Total						**326,391**

Note: Values are recoverable hydrocarbons as of 12-31-90; Subregions for BO, EGO are <40m, 40-200m, 200-1000m, and >1000m water depth; LO is 0-200m and 200-2000m; AO and West Florida have no defined water depth.

TABLE 2-12

UNDISCOVERED TIGHT GAS RESOURCE IN OLD PLAYS CURRENT TECHNOLOGY
(Billion Cubic Feet)

Region		0-5,000'	5-10,000'	10-15,000'	>15,000'	Total
Appalachia	A	2,311	1,075	0	0	3,386
MAFLA Onshore	B	0	0	0	0	0
Midwest	C	0	0	0	0	0
Arkla-E. Texas	D	571	1,845	1,532	263	4,211
So. Louisiana	E	0	0	0	0	0
Texas Gulf Coast	G	31	5,440	1,018	654	7,143
Williston	WL	386	0	0	0	386
Rockies Foreland	FR	1,759	8,592	7,070	8,993	26,414
San Juan Basin	SJB	522	783	0	0	1,305
Overthrust	OV	0	0	0	0	0
Midcontinent	JN	289	1,546	1,088	5,471	8,394
Permian	JS	632	1,116	584	0	2,332
Pacific	L	0	0	0	0	0
Subtotal Onshore		**6,501**	**20,397**	**11,292**	**15,381**	**53,571**
		Subregion				
		1	**2**	**3**	**4**	**Total**
Norphlet	BO	0				0
West Florida						0
Gulf of Mexico	EGO	0	0	0	0	0
Pacific Offshore	LO	0		0		0
Atlantic Offshore	AO					0
Subtotal Offshore						**0**
Grand Total						**53,571**

Note: Values are recoverable hydrocarbons as of 12-31-90; Subregions for BO, EGO are <40m, 40-200m, 200-1000m, and >1000m water depth; LO is 0-200m and 200-2000m; AO and West Florida have no defined water depth.

not restricted and there was an assumption of continued advances in resource evaluation and development technologies.

The EIA estimate of undiscovered onshore conventional resources in the lower-48 states is 197 TCF (22 percent lower than the NPC value of 254 TCF). Similarly, the EIA offshore estimate is lower than the NPC assessment by 18 percent. Elements of the method by which resource estimates were made by both the NPC and EIA such as a literature search of other resource assessments were the same. Major differences include the participation and inputs of company-specific evaluations of specific producing regions of the lower-48 states, which were included in the NPC study and not in the EIA evaluation. Additionally, the reference scenario utilized by the EIA was limited to evaluating resources in minimum field sizes of about 30,000 BOE onshore, and of 100,000 BOE offshore.

USGS-MMS/1989

Two agencies of the U.S. Department of the Interior, the U.S. Geological Survey and the Minerals Management Service (MMS), completed and published an assessment of undiscovered conventional gas resources in the United States in 1989. Data and estimates presented by the USGS covered onshore areas of the lower-48 states and Alaska, as well as state waters. MMS inputs were focused on federal offshore areas. Results were published together in a document entitled *Estimates of Undiscovered Conventional Oil and Gas Resources in the United States—A Part of the Nation's Energy Endowment.*

The Interior Department study was specifically intended to examine undiscovered conventionally recoverable oil and gas. In addition, recoverable resource estimates were further subjected to economic criteria. Table 2-13 reports the recoverable volumes not reduced by economic filters. The methodology employed to develop the Interior Department estimates is based on a probabilistic geologic play-oriented approach with some variances. The play approach requires estimation of the number and sizes of potential fields in a given area or the summation of individual prospect evaluations. The probability of occurrence of certain resource estimates is also considered and statistically evaluated with the mean estimate presented in Table 2-13. This process is similar to that conducted by many large exploration and production companies, as were represented in the NPC study. However, the element of risk and probabilistic occurrence may be evaluated differently by individual companies and the Interior Department.

Compared to the NPC study, volumes estimated by the combined USGS-MMS effort for the lower-48 states were 22 percent lower. However, some of the difference can be accounted for inasmuch as the Interior Department assessment evaluated onshore resources only for fields greater than about 30,000 BOE and offshore fields greater than 100,000.

PGC/1990

The Potential Gas Committee, part of the Potential Gas Agency at the Colorado School of Mines, consists of volunteer members from all segments of the oil and gas industry with the task of providing resource estimates of natural gas based upon expert experience and knowledge. Resource estimates are developed for each region of the United States and given in terms of minimum, most likely, and maximum estimates for gas resources categorized as probable, possible, or speculative. Committee volunteers assess over 55 separate geologic provinces in the lower-48 states. To evaluate the undiscovered conventional resource without the influence of reserves growth, the NPC decided to consider only the possible and speculative categories in the group's consensus process. In the 1990 edition of *Potential Supply of Natural Gas in the United States*, the

TABLE 2-13

COMPARISON OF LOWER-48 UNDISCOVERED CONVENTIONAL RESOURCE ESTIMATES (Trillion Cubic Feet)

	Onshore	Offshore	Total
DOE – 1988*	219	134	353
EIA – 1990 †	197	130	327
USGS/MMS – 1989 ‡	189	135	324
PGC – 1990 §	352	139	491
GRI – 1992 ¶	—	—	394
NPC – 1992 #	254	159	413

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* Current technology only.

† Access to federal lands and Advanced Technology scenario.

‡ Excludes resource in fields less than 6 billion cubic feet.

§ Summation of mean values. Includes some tight gas in old plays.

¶ Excludes tight gas in old plays. Advanced Technology case.

Advanced Technology case.

TABLE 2-14

TOTAL UNDISCOVERED GAS RESOURCE
ADVANCED TECHNOLOGY
(INCLUDES TIGHT GAS IN OLD PLAYS)
(Billion Cubic Feet)

Region		**0-5,000'**	**5-10,000'**	**10-15,000'**	**>15,000'**	**Total**
Appalachia	A	7,762	11,747	5,419	2,375	27,302
MAFLA Onshore	B	939	393	6,015	4,652	11,999
Midwest	C	2,373	4,290	2,665	0	9,328
Arkla-E. Texas	D	4,456	8,656	7,394	1,554	22,060
So. Louisiana	E	0	613	2,551	13,551	16,715
Texas Gulf Coast	G	2,766	20,119	21,362	9,255	53,502
Williston	WL	1,195	1,319	492	0	3,006
Rockies Foreland	FR	4,638	21,531	16,271	21,583	64,023
San Juan Basin	SJB	1,496	2,492	0	0	3,988
Overthrust	OV	330	4,170	4,123	4,807	13,430
Midcontinent	JN	5,417	14,276	13,260	26,262	59,215
Permian	JS	4,197	7,269	5,291	13,561	30,318
Pacific	L	1,591	7,400	5,609	4,684	19,283
Subtotal Onshore		**37,159**	**104,274**	**90,452**	**102,284**	**334,168**
		Subregion				
		1	**2**	**3**	**4**	**Total**
Norphlet	BO	12,527				12,527
West Florida						2,849
Gulf of Mexico	EGO	27,842	25,434	17,294	40,042	110,613
Pacific Offshore	LO	3,088		11,224		14,312
Atlantic Offshore	AO					18,714
Subtotal Offshore						**159,015**
Grand Total						**493,183**

Note: Values are recoverable hydrocarbons as of 12-31-90; Subregions for BO, EGO are <40m, 40-200m, 200-1000m, and >1000m water depth; LO is 0-200m and 200-2000m; AO and West Florida have no defined water depth.

PGC reported both most likely values summed arithmetically and the statistical mean values for total lower-48 data. The latter values are referenced in this report.

PGC estimates of undiscovered conventional resources for the lower-48 states exceed that of the NPC assessment by approximately 19 percent. This is in part due to PGC inclusion of tight formations and shale gas in its fundamental resource evaluation. For the most part, the PGC considers many tight formation reservoirs and shale reservoirs as part of the mainstream gas supply and not separable from other resource types.

GRI/1991

The Gas Research Institute (GRI) annually models natural gas demand and supply utilizing the HSM (a version of which was used for this NPC study) and presents results in its annual *Baseline Projection*. The GRI Baseline and other GRI publications detail the output and assumptions utilized in building that year's projection. .Among the model inputs are estimates of resources available for discovery and eventual development. Of course, GRI projections include assumptions of technology growth that influence the amount of resource available and the cost at which it might be brought to market.

GRI's December 1991 publication *The Long-Term Trends in U.S. Gas Supply and Prices: 1992 Edition of the GRI Baseline Projection of US. Energy Supply and Demand to 2010* outlines assumptions regarding the resource base in the HSM. The lower-48 undiscovered resource base is estimated to be 394 TCF (4 percent lower than that estimated by the NPC) for the advanced technology case. A minimum field size of 4,000 BOE was included in both the GRI's work and the NPC estimates.

Advanced Technology

The assessment of the undiscovered resource base began by assuming today's technology. Since the resource base is identifying recoverable hydrocarbons, its size will change as technological advances are made that affect the recovery of gas in place. History has shown that technology has continued to advance over time and while it is very difficult to forecast the exact nature of technological advances and breakthroughs that will occur, it seems inevitable that they will happen.

The conventional gas resource is one that has been exploited extensively in the past, and technological advances affecting recovery of gas in place have been many and substantial in their impact. However, as recovery of conventional gas in place is typically in the 70 to 80 percent range, it is considered likely that further increases in recovery factors will be small.

TABLE 2-15

UNDISCOVERED ASSOCIATED AND DISSOLVED GAS RESOURCE
ADVANCED TECHNOLOGY
(Billion Cubic Feet)

Region		**0-5,000'**	**5-10,000'**	**10-15,000'**	**>15,000'**	**Total**
Appalachia	A	108	86	41	0	234
MAFLA Onshore	B	90	54	776	40	959
Midwest	C	1,260	1,278	40	0	2,577
Arkla-E. Texas	D	1,088	2,119	187	0	3,394
So. Louisiana	E	0	117	362	0	479
Texas Gulf Coast	G	350	1,437	799	0	2,585
Williston	WL	191	574	215	0	980
Rockies Foreland	FR	710	2,342	482	0	3,533
San Juan Basin	SJB	330	744	0	0	1,074
Overthrust	OV	53	673	96	0	822
Midcontinent	JN	2,118	3,029	854	0	6,001
Permian	JS	1,243	1,913	776	0	3,931
Pacific	L	311	1,125	664	422	2,523
Subtotal Onshore		**7,851**	**15,490**	**5,289**	**462**	**29,092**
				Subregion		
		1	**2**	**3**	**4**	**Total**
Norphlet	BO	0				0
West Florida						87
Gulf of Mexico	EGO	2,339	2,136	3,642	8,434	16,551
Pacific Offshore	LO	1,618		5,882		7,500
Atlantic Offshore	AO					568
Subtotal Offshore						**24,705**
Grand Total						**53,797**

Note: Values are recoverable hydrocarbons as of 12-31-90; Subregions for BO, EGO are <40m, 40-200m, 200-1000m, and >1000m water depth; LO is 0-200m and 200-2000m; AO and West Florida have no defined water depth.

TABLE 2-16

UNDISCOVERED CONVENTIONAL NON-ASSOCIATED GAS RESOURCE
ADVANCED TECHNOLOGY
(Billion Cubic Feet)

Region		0-5,000'	5-10,000'	10-15,000'	>15,000'	Total
Appalachia	A	4,188	10,049	5,378	2,375	21,989
MAFLA Onshore	B	849	339	5,239	4,612	11,040
Midwest	C	1,113	3,012	2,626	0	6,751
Arkla-E. Texas	D	2,511	3,770	4,909	1,159	12,350
So. Louisiana	E	0	496	2,189	13,551	16,236
Texas Gulf Coast	G	2,369	10,523	19,037	8,274	40,203
Williston	WL	425	745	277	0	1,447
Rockies Foreland	FR	1,290	6,301	5,184	8,094	20,869
San Juan Basin	SJB	383	574	0	0	957
Overthrust	OV	277	3,497	4,027	4,807	12,608
Midcontinent	JN	2,866	8,928	10,775	18,055	40,623
Permian	JS	2,006	3,682	3,640	13,561	22,889
Pacific	L	1,279	6,274	4,945	4,261	16,760
Subtotal Onshore		**19,557**	**58,188**	**68,225**	**78,750**	**224,720**
				Subregion		
		1	**2**	**3**	**4**	**Total**
Norphlet	BO	12,527				12,527
West Florida						2,762
Gulf of Mexico	EGO	25,504	23,298	13,652	31,609	94,062
Pacific Offshore	LO	1,470		5,343		6,812
Atlantic Offshore	AO					18,147
Subtotal Offshore						**134,310**
Grand Total						**359,030**

Note: Values are recoverable hydrocarbons as of 12-31-90; Subregions for BO, EGO are <40m, 40-200m, 200-1000m, and >1000m water depth; LO is 0-200m and 200-2000m; AO and West Florida have no defined water depth.

The assumption regarding technology advancement for conventional gas is a 0.5 percent per year increase in recovery factor, which suggests that the recovery factor in 1990 will grow by 10 percent by 2010. (In other words, a 75 percent recovery factor in 1990 would be 82.5 percent in 2010 due to the advancement of technology; the gas in place estimate would be unchanged.)

In other parts of the overall NPC gas study, the advancement of technology for nonconventional resources has been addressed and it was concluded that recovery factors for that resource would grow by 2 percent per year or 50 percent by 2010. This more rapid advancement of technology as related to nonconventional gas recovery is possible because current recovery factors for large portions of the nonconventional resource base are quite low compared to conventional gas.

Tables 2-14 through 2-17 depict the gas resource base under advanced technology for that part of the resource base represented by the finding rate equations.

COST ASSUMPTIONS

Onshore Drilling and Completion Costs

The Hydrocarbon Supply Model uses estimates of capital and operating costs for the exploration, development, and production phases of a discovery for field economic calculations. Regional costs vary due to geography, climate, and reservoir depth.

Onshore well costs vary by region, drilling depth, and well type—oil, gas, or dry holes. In addition, they can be affected by whether the wells are stimulated. The Joint Association Survey (JAS) reports onshore well cost data by region, depth, and type.

Subregional detail in the 1988 survey was aggregated to estimate regional averages for the depth intervals utilized in the HSM. These well costs are shown in Tables 2-18 and 2-19. No distinction is made between exploration or development wells. Dry hole costs are added in the development stage based on the historical ratio of dry holes to successful wells in that region shown in Table 2-20.

In addition to the standard costs of drilling and completion, gas wells drilled in tight reservoirs are assumed to have the additional well stimulation costs shown at the bottom of Table 2-18. These costs apply only to the onshore regions because no tight gas is modeled for the offshore regions.

The HSM calculates changes to constant dollar base drilling costs over time as industry activity and oil and gas prices change. Regression-based algorithms estimated from a review

TABLE 2-17

UNDISCOVERED TIGHT GAS RESOURCE IN OLD PLAYS
ADVANCED TECHNOLOGY
(Billion Cubic Feet)

Region		0-5,000'	5-10,000'	10-15,000'	>15,000'	Total
Appalachia	A	3,467	1,613	0	0	5,079
MAFLA Onshore	B	0	0	0	0	0
Midwest	C	0	0	0	0	0
Arkla-E. Texas	D	857	2,768	2,298	395	6,317
So. Louisiana	E	0	0	0	0	0
Texas Gulf Coast	G	47	8,160	1,527	981	10,715
Williston	WL	579	0	0	0	579
Rockies Foreland	FR	2,639	12,888	10,605	13,490	39,621
San Juan Basin	SJB	783	1,175	0	0	1,958
Overthrust	OV	0	0	0	0	0
Midcontinent	JN	434	2,319	1,632	8,207	12,591
Permian	JS	948	1,674	876	0	3,498
Pacific	L	0	0	0	0	0
Subtotal Onshore		**9,752**	**30,596**	**16,938**	**23,072**	**80,357**
				Subregion		
		1	**2**	**3**	**4**	**Total**
Norphlet	BO	0				0
West Florida						0
Gulf of Mexico	EGO	0	0	0	0	0
Pacific Offshore	LO	0		0		0
Atlantic Offshore	AO					0
Subtotal Offshore						**0**
Grand Total						**80,357**

Note: Values are recoverable hydrocarbons as of 12-31-90; Subregions for BO, EGO are <40m, 40-200m, 200-1000m, and >1000m water depth; LO is 0-200m and 200-2000m; AO and West Florida have no defined water depth.

TABLE 2-18

ONSHORE GAS WELL COSTS
(Thousands of 1988 Dollars)

Region		0-5,000'	5-10,000'	10-15,000'	>15,000'
Appalachia	A	115	250	1,420	3,760
MAFLA Onshore	B	130	304	1,574	3,425
Midwest	C	125	519	1,809	—
Arkla-E. Texas	D	90	495	1,101	3,760
So. Louisiana	E	—	536	1,556	4,013
Texas Gulf Coast	G	101	453	1,608	3,605
Williston	WL	45	350	1,400	—
Rockies Foreland	FR	202	322	1,395	5,010
San Juan Basin	SJB	202	322	1,395	5,010
Overthrust	OV	212	335	1,465	5,260
Midcontinent	JN	122	381	1,079	3,316
Permian	JS	173	326	1,303	3,445
Pacific	L	201	437	1,013	3,760
Additional Stimulation Cost Applied to Low-Permeability Gas Wells:					
Lower-48 Average		78	89	103	118

TABLE 2-19

ONSHORE DRY HOLE COSTS
(Thousands of 1988 Dollars)

Region		0-5,000'	5-10,000'	10-15,000'	>15,000'
Appalachia	A	37	200	840	2829
MAFLA Onshore	B	73	178	607	2437
Midwest	C	61	326	993	—
Arkla-E. Texas	D	40	167	721	2761
So. Louisiana	E	—	404	966	3144
Texas Gulf Coast	G	52	259	892	2880
Williston	WL	67	257	710	2820
Rockies Foreland	FR	105	176	780	3600
San Juan Basin	SJB	105	176	780	3600
Overthrust	OV	110	185	820	3790
Midcontinent	JN	58	189	739	2846
Permian	JS	109	249	595	2545
Pacific	L	110	344	812	2832

of 1970 through 1988 historical data were utilized to create an index of future costs. Each depth interval utilizes a separate algorithm that relates a drilling cost index to oil and gas prices and active rotary rig counts. The number of onshore rigs required to drill each year's wells is based upon annual footage capability per rig, which is estimated from JAS data. This estimate will change with technology change assumptions.

Offshore Drilling and Completion Costs

Offshore well costs are strongly affected by the water depth and the purpose (exploratory or developmental) of the well. This is because the equipment utilized can differ substantially as a function of depth. The JAS does not report offshore well costs by water

TABLE 2-20

DEVELOPMENT WELL SUCCESS RATES

Appalachia	A	89.3%
MAFLA Onshore	B	55.7%
Midwest	C	69.0%
Arkla-E. Texas	D	72.9%
So. Louisiana	E	55.1%
Texas Gulf Coast	G	78.2%
Williston	WL	73.7%
Rockies Foreland	FR	81.4%
San Juan Basin	SJB	81.4%
Overthrust	OV	81.4%
Midcontinent	JN	72.7%
Permian	JS	90.5%
Pacific	L	95.6%
Norphlet	BO	90.0%
Gulf of Mexico	EGO	64.1%
Pacific Offshore	LO	94.5%

depth or by purpose. Accordingly, a framework was developed to estimate average offshore drilling costs for the four water depths in the Gulf of Mexico and the Norphlet trend. This framework was normalized to the drilling costs reported in the 1988 JAS. Gulf of Mexico results were extended by analogy to the offshore Pacific region. Offshore Pacific drilling costs are roughly 10 to 20 percent higher than the Gulf of Mexico according to the JAS. The increased costs are primarily due to the harder rock of the Pacific basins and environmental regulations. The typical cost of an offshore Pacific well was estimated by increasing the average Gulf Coast cost in each water depth category by 20 percent.

Gulf of Mexico offshore base year (1988) well costs are presented in Table 2-21. Average well costs utilized in the model are a composite of exploration and development wells in the ratio of about 70 percent development and 30 percent exploration. The average well is assumed drilled to a measured depth of about 11,000 feet.

Onshore Facilities Costs

Well costs include all drilling and completion costs through the "Christmas tree." Additional items past the Christmas tree needed for producing wells (e.g., flowline and connections, separators, dehydrators, pumps, and storage tanks) are included as lease equipment costs. Estimates for lease equipment costs were derived from an annual survey conducted by the Dallas Field Office of the Energy Information Administration. Estimates for lease equipment costs are by region and depth interval as shown in Table 2-22. Dry holes do not have any lease equipment costs.

Offshore Facilities Costs

Within the model, the Central and Western Gulf of Mexico Offshore region is broken down into four water-depth intervals: 0 to 40 meters, 40 to 200 meters, 200 to 1,000 meters, and 1,000 to 2,000 meters. The Norphlet trend offshore Alabama, Mississippi, and Florida is included in region BO1. The eastern Gulf of Mexico (west Florida shelf) is included in region BO2. The Atlantic continental shelf is region AO. Instead of water-depth intervals, this region is divided into three geographic regions running from north to south. The offshore Pacific is broken down into two intervals: 0 to 200 meters and 200 to 1,000 meters. For the purpose of developing costs for wells, platforms, etc., "average" or "typical" physical parameters are assumed for each interval. Because of the lack of proved reserves or approved production operation plans, development costs for the eastern Gulf of Mexico and Atlantic offshore regions are assumed to be similar to the deepwater Pacific offshore region. Offshore region assumptions are shown in Table 2-23.

There has been extensive oil and gas exploration and development in the Gulf of Mexico shelf intervals and, thus, the costs developed for these areas are considered fairly reliable. The costs developed for the Gulf slope intervals and the Pacific are more uncertain because there has been little development in these areas on which to base the cost estimates.

The platform cost estimates for depths greater than 1,350 feet are based on the limited experience to date with tension leg production platforms.

The Pacific Coast has much fewer offshore developments than the Gulf of Mexico, none of which are non-associated gas producers. Pacific

TABLE 2-21

OFFSHORE U.S. DRILLING AND COMPLETION COSTS
(1988 Dollars)

Water Depth	0 - 40 Meters		40-200 Meters		200-1,000 Meters		1,000- 2,000 Meters		Norphlet	
	Devel	Expl	Devel	Expl	Devel	Expl	Devel	Expl	Devel	Expl
Well depth, Feet measured depth	11,000	11,000	11,000	11,000	11,000	11,000	11,000	11,000	24,000	24,000
Days	55	54	55	54	55	56	57	56	200	190
Rig Rental, $MM	$28.8	$33.1	$28.8	$43.9	$28.8	$83.5	$135.7	$135.7	$32.8	$47.9
Well Costs, $M/well										
Rig Mobilization		$316	*	$348	$250	$506	*	$556	$250	$316
Transportation	$122	$122	$134	$134	$146	$146	$158	$158	$186	$186
Mud, pressure control	$262	$262	$262	$262	$262	$262	$262	$262	$994	$994
Logging	$296	$296	$296	$296	$296	$296	$296	$296	$900	$900
Perforating	$584	$584	$584	$584	$584	$584	$584	$584	$888	$888
Casing, tubing, wellhead	$805	$644	$813	$652	$821	$660	$829	$668	$4,170	$3,336
Special tools	$265	$265	$265	$265	$265	$265	$265	$265	$402	$402
Overhead, other	$285	$343	$285	$343	$285	$343	$285	$343	$428	$534
Rig daily costs	$1,585	$1,776	$1,585	$2,357	$1,585	$4,676	$7,733	$7,597	$6,564	$9,093
Totals	**$4,204**	**$4,608**	**$4,224**	**$5,241**	**$4,494**	**$7,738**	**$10,412**	**$10,061**	**$10,612**	**$13,313**

TABLE 2-22

ONSHORE GAS WELL LEASE EQUIPMENT COSTS
(Thousands of 1988 Dollars Per Well)

	Region	Depth 1 0-5,000 ft	Depth 2 5-10,000 ft	Depth 3 10-15,000 ft	Depth 4 >15,000 ft
A	East	14	22	35	35
B	FL, MS, AL	19	31	35	35
C	Midwest	19	31	35	35
D	N. LA, N.E. TX, AR	19	31	35	35
E	S. LA Onshore	19	31	35	35
G	S. TX Onshore	19	31	35	35
WL	Williston Basin	29	36	39	40
FR	Foreland	29	36	39	40
SJB	San Juan Basin	29	36	39	40
OV	Western Thrust Belt	29	36	39	40
JN	Midcontinent	19	31	35	35
JS	Permian Basin	19	31	35	35
L	Pacific Coast Onshore	19	31	35	35

TABLE 2-23

OFFSHORE REGION ASSUMPTIONS

	Model Region	Water Depth	Miles to Shore	Well Depth
BO-1	Norphlet Trend	40 ft	20 miles	24,000 ft (MD)
BO-2	Eastern Gulf	—	100 miles	11,000 ft (MD)
EGO-1	LA,TX: 0-40 meters	75 ft	30 miles	11,000 ft (MD)
EGO-2	LA,TX: 40-200 meters	400 ft	70 miles	11,000 ft (MD)
EGO-3	LA,TX: 200-1,000 meters	1,350 ft	100 miles	11,000 ft (MD)
EGO-4	LA,TX: 1,000-2,000 meters	4,500 ft	150 miles	11,000 ft (MD)
LO-1	Off. Pacific: 0-200 meters	200 ft	8 miles	10,000 ft (MD)
LO-3	Off. Pac.: 200-2,000 meters	—	25 miles	11,000 ft (MD)
AO-1	North Atlantic	—	50 miles	11,000 ft (MD)
AO-2	Central Atlantic	—	50 miles	11,000 ft (MD)
AO-3	South Atlantic	—	50 miles	11,000 ft (MD)

Coast platforms tend to be larger and heavier than those in the Gulf because of earthquake risks. Fields are generally developed with fewer platforms than comparable fields in the Gulf because of the rapid increase in water depth of the Pacific continental slope and stringent environmental regulations.

The Atlantic offshore regions and the eastern Gulf of Mexico do not yet have any development history. Because of this costs in these areas are assumed to be similar to the deepwater Pacific.

The development plan for any particular field is a function of field size (total reserves, number of wells required to drain), water depth, location, and well productivity, as well as the capital investment required in platforms, wells, and pipelines. In addition, a producer's requirements for the development schedule of a field and for well maintenance operations also will influence the physical configuration chosen for field development. For example, the offshore Norphlet gas trend is being developed with a relatively large number of small platforms because of the high productivity and wide spacing of wells, the shallow water depth, and because most exploration wells are re-entered for completion as producers.

No published comprehensive survey exists for offshore production platform costs as exists for well and lease equipment costs. The costs for offshore production platforms were developed from published case histories.

Costs for conventional steel jacket platforms were adapted from cost equations presented in a study by USGS, which included cost estimates for oil and gas exploration and production in the Gulf Shelf. These costs include only the cost of materials and fabrication for the platform jacket, deck, piles, and installation. The costs for the production facilities are not included.

Platform cost estimates for the deepwater slope interval are based on analysis of published engineering cost estimates. The development scheme selected for a deepwater field depends on reserves and well productivity as well as water depth and capital costs. Floating tension leg system costs are not very sensitive to water depth, relative to fixed conventional platforms.

Other development options, such as a fully developed tension leg platform with primary and secondary production processing facilities on the platform, or a floating production platform tethered to subsea wellheads, have been utilized by operators depending on field specific situations. As mentioned earlier, all of these floating systems are relatively insensitive to water depth, and for many fields requiring five to thirty wells to develop, the total costs are similar.

The costs for offshore platforms and equipment in the model are presented in Tables 2-24 through 2-30. The costs for the Gulf Offshore are divided into four water-depth designations for offshore Texas and Louisiana and the Norphlet trend off of Alabama, Mississippi, and Florida. Platform costs for the Pacific Offshore were based on water depths of 400 feet for the shelf and a mix of deepwater conventional platforms and tension leg platforms for the slope. Pacific deepwater platform costs are a composite based on 70 percent conventional steel platforms and 30 percent tension leg platforms. Each field is assumed to have at least one platform. For larger fields, the costs may be for two or more platforms.

Development wells in the shelf intervals are assumed to be drilled with platform rigs. The cost for transporting and setting up the rigs on the platform are included in the field development costs. One rig is assumed for each platform of size up to 18 slots. Two rigs are assumed for larger platforms. Rig mobilization costs of $250,000 for jack-ups were common in 1988. A mobilization charge of $400,000 is assumed for semi-submersibles. Platform rigs are assumed to cost $1.4 million to mobilize.

Abandonment costs for the shallow water areas (<40 meters) were assumed to be $1 million per structure plus $200,000 per well. Costs for water depths of 40 to 200 meters were assumed to be 25 percent higher and costs at 200 to 1,000 meters were assumed to be 75 percent higher than the <40 meter interval. Well abandonment costs in the ultra-deepwater fields are assumed to be $1 million each because of the use of a dynamically positioned semi-submersible drilling rig rather than a platform rig for the abandonments.

In all cases, gas pipeline construction costs are assumed to be borne by gas pipeline companies. The gathering charges paid by producers are computed on a dollar per MCF of production elsewhere in the model. The Norphlet deep gas offshore Alabama is an exception to the standard treatment of gas pipeline costs. Producers are assumed to pay the capital costs of pipeline construction from the field to onshore gas plants because of the highly corrosive composition of Norphlet gas.

Onshore Operating Costs

Operating and maintenance costs are estimated as annual costs per well and are represented by onshore region and depth interval. These costs, shown in Table 2-31, were derived from the same EIA survey utilized to develop lease equipment costs. Additional operating costs attributable to non-hydrocarbon gas removal are explicitly added in several areas. The costs are included in the model as an operating

TABLE 2-24

GULF OF MEXICO
GAS FIELD DEVELOPMENT COSTS
75 FOOT WATER DEPTH–30 MILES TO SHORE
(Millions of 1988 Dollars)

Field Size Class	# Wells	# Plat	Slots/ Plat	Resv (BCF)	Cost per Plat	Total Plat Costs	Plat Rig Mob	Gas Prod Eqpt	PV of Net Aband	Liq P/L	Prod Wells D&C	Total
1	1	1	4	0.02	4.9	4.9	0.3	1.0	0.4	0.0	0.9	7.4
2	1	1	4	0.05	4.9	4.9	0.3	1.4	0.4	0.0	0.9	7.8
3	1	1	4	0.10	4.9	4.9	0.3	1.9	0.4	0.0	0.9	8.3
4	1	1	4	0.19	4.9	4.9	0.3	2.5	0.4	0.0	0.9	8.9
5	1	1	4	0.38	4.9	4.9	0.3	3.3	0.4	0.0	0.9	9.7
6	1	1	4	0.76	4.9	4.9	0.3	4.4	0.4	0.0	0.9	10.8
7	1	1	4	1.5	4.9	4.9	0.3	5.9	0.4	0.0	0.9	12.3
8	1	1	4	3.1	4.9	4.9	0.3	7.9	0.4	0.0	1.5	15.0
9	2	1	4	6.1	4.9	4.9	0.3	10.6	0.4	0.0	2.8	19.0
10	2	1	4	12	4.9	4.9	1.4	14.2	0.5	0.0	5.1	26.0
11	4	1	6	24	5.5	5.5	1.4	19.0	0.6	5.4	9.5	41.3
12	7	1	8	49	6.1	6.1	1.4	25.4	0.8	5.4	18.1	57.2
13	12	1	16	98	8.7	8.7	1.4	34.0	1.1	5.4	32.8	83.3
14	19	1	20	195	10.0	10.0	2.8	43.5	1.5	5.4	53.2	116.4
15	31	1	32	391	13.8	13.8	2.8	55.5	2.2	5.4	86.0	165.7
16	49	2	26	790	11.9	23.7	5.6	105.3	3.7	5.4	138.9	282.7
17	77	3	26	1,564	11.9	35.6	8.4	166.4	5.8	7.7	219.4	443.4
18	123	5	26	3,129	11.9	59.3	14.0	277.4	9.3	10.0	351.7	721.7
19	196	7	30	6,255	13.1	91.9	19.6	410.8	14.6	10.0	561.7	1,108.5
20	312	11	30	12,516	13.1	144.4	30.8	633.1	23.1	12.1	895.3	1,738.9

TABLE 2-25

GULF OF MEXICO
GAS FIELD DEVELOPMENT COSTS
400 FOOT WATER DEPTH–40 MILES TO LIQUID TRUNKLINE–
70 MILES TO SHORE
(Millions of 1988 Dollars)

Field Size Class	# Wells	# Plat	Slots/ Plat	Resv (BCF)	Cost per Plat	Total Plat Costs	Plat Rig Mob	Gas Prod Eqpt	PV of Net Aband	Liq P/L	Prod Wells D&C	Total
1	1	1	4	0.02	15.8	15.8	0.3	1.0	0.5	0.0	1.0	18.4
2	1	1	4	0.05	15.8	15.8	0.3	1.4	0.5	0.0	1.0	18.9
3	1	1	4	0.10	15.8	15.8	0.3	1.9	0.5	0.0	1.0	19.4
4	1	1	4	0.19	15.8	15.8	0.3	2.5	0.5	0.0	1.0	20.0
5	1	1	4	0.38	15.8	15.8	0.3	3.3	0.5	0.0	1.0	20.8
6	1	1	4	0.76	15.8	15.8	0.3	4.4	0.5	0.0	1.0	21.9
7	1	1	4	1.5	15.8	15.8	0.3	5.9	0.5	0.0	1.0	23.4
8	1	1	4	3.1	15.8	15.8	0.3	7.9	0.5	0.0	1.4	25.9
9	2	1	4	6.1	15.8	15.8	0.3	10.6	0.5	0.0	2.7	30.0
10	2	1	4	12	15.8	15.8	1.4	14.2	0.5	0.0	4.8	36.7
11	4	1	6	24	17.2	17.2	1.4	19.0	0.6	8.0	9.0	55.2
12	7	1	8	49	18.6	18.6	1.4	25.4	0.8	8.0	17.2	71.3
13	12	1	16	98	24.1	24.1	1.4	34.0	1.1	8.0	32.0	100.6
14	19	1	20	195	26.9	26.9	2.8	43.5	1.6	8.0	52.4	135.1
15	30	1	32	391	35.2	35.2	2.8	55.5	2.3	11.8	84.7	192.3
16	48	2	26	790	31.0	62.0	5.6	105.3	3.8	11.8	137.6	326.3
17	75	3	26	1,564	31.0	93.1	8.4	166.4	5.9	16.9	215.7	506.4
18	120	4	32	3,129	35.2	140.6	11.2	243.8	9.1	21.8	345.1	771.7
19	191	6	32	6,255	35.2	211.0	16.8	375.7	14.4	21.8	549.3	1,189.0
20	303	10	32	12,516	35.2	351.6	28.0	599.1	23.0	26.5	871.4	1,899.7

TABLE 2-26

GULF OF MEXICO
GAS FIELD DEVELOPMENT COSTS
1,350 FOOT WATER DEPTH–50 MILES TO LIQUID TRUNKLINE–100 MILES TO SHORE
(Millions of 1988 Dollars)

Field Size Class	# Wells	# Plat	Slots/ Plat	Resv (BCF)	Cost per Plat	Total Plat Costs	Plat Rig Mob	Gas Prod Eqpt	PV of Net Aband	Liq P/L	Prod Wells D&C	Total
1	1	1	4	0.02	140.7	140.7	0.4	1.0	0.7	0.0	1.0	143.7
2	1	1	4	0.05	140.7	140.7	0.4	1.4	0.7	0.0	1.0	144.1
3	1	1	4	0.10	140.7	140.7	0.4	1.9	0.7	0.0	1.0	144.6
4	1	1	4	0.19	140.7	140.7	0.4	2.5	0.7	0.0	1.0	145.2
5	1	1	4	0.38	140.7	140.7	0.4	3.3	0.7	0.0	1.0	146.0
6	1	1	4	0.76	140.7	140.7	0.4	4.4	0.7	0.0	1.0	147.1
7	1	1	4	1.5	140.7	140.7	0.4	5.9	0.7	0.0	1.0	148.7
8	1	1	4	3.1	140.7	140.7	0.4	7.9	0.7	0.0	1.5	151.2
9	2	1	4	6.1	140.7	140.7	0.4	10.6	0.7	0.0	2.9	155.3
10	2	1	4	12	140.7	140.7	1.4	14.2	0.8	0.0	4.8	161.8
11	4	1	6	24	144.9	144.9	1.4	19.0	1.0	10.7	9.0	185.9
12	7	1	8	49	149.1	149.1	1.4	25.4	1.3	10.7	17.2	205.0
13	12	1	16	98	165.9	165.9	1.4	34.0	1.8	10.7	32.0	245.8
14	19	1	20	195	174.3	174.3	2.8	43.5	2.6	10.7	52.4	286.3
15	30	1	32	391	199.5	199.5	2.8	55.5	3.8	17.9	84.7	364.2
16	48	2	26	790	186.9	373.9	5.6	105.3	6.4	17.9	137.6	646.7
17	75	2	40	1,564	216.4	432.7	5.6	131.6	9.4	25.5	216.2	821.1
18	120	2	60	3,129	258.4	516.8	5.6	163.2	14.3	32.9	347.2	1,080.0
19	191	4	50	6,255	237.4	949.6	11.2	297.1	23.3	32.9	553.8	1,867.8
20	303	6	52	12,516	241.6	1,449.6	16.8	445.7	36.7	40.0	879.7	2,868.6

TABLE 2-27

GULF OF MEXICO
GAS FIELD DEVELOPMENT COSTS
4,500 FOOT WATER DEPTH–50 MILES TO LIQUID TRUNKLINE–150 MILES TO SHORE
(Millions of 1988 Dollars)

Field Size Class	# Wells	# Plat	Slots/ Plat	Resv (BCF)	Cost per Plat	Total Plat Costs	Plat Rig Mob	Gas Prod Eqpt	PV of Net Aband	Liq P/L	Prod Wells D&C	Total
1	1	1	10	0.02	247.6	247.6	0.4	1.0	1.1	0.0	2.0	252.1
2	1	1	10	0.05	247.6	247.6	0.4	1.4	1.1	0.0	2.0	252.5
3	1	1	10	0.10	247.6	247.6	0.4	1.9	1.1	0.0	2.0	253.0
4	1	1	10	0.19	247.6	247.6	0.4	2.5	1.1	0.0	2.0	253.6
5	1	1	10	0.38	247.6	247.6	0.4	3.3	1.1	0.0	2.0	254.4
6	1	1	10	0.76	247.6	247.6	0.4	4.4	1.1	0.0	2.0	255.5
7	1	1	10	1.5	247.6	247.6	0.4	5.9	1.1	0.0	2.0	257.0
8	1	1	10	3.1	247.6	247.6	0.4	7.9	1.2	0.0	3.0	260.1
9	2	1	10	6.1	247.6	247.6	0.4	10.6	1.4	0.0	5.7	265.8
10	2	1	10	12	247.6	247.6	0.4	14.2	1.5	0.0	7.0	270.7
11	3	1	10	24	247.6	247.6	1.4	19.0	2.2	11.9	15.6	297.7
12	6	1	10	49	247.6	247.6	1.4	25.4	3.7	11.9	33.8	323.9
13	10	1	20	98	270.1	270.1	2.8	34.0	6.0	11.9	61.3	386.2
14	16	1	20	195	270.1	270.1	2.8	43.5	9.2	11.9	100.3	437.9
15	26	1	30	391	297.2	297.2	2.8	55.5	14.8	27.2	167.0	564.4
16	40	1.3	30	790	297.2	382.6	3.8	83.7	23.0	27.2	264.4	784.7
17	64	2.1	30	1,564	297.2	574.1	5.9	136.1	36.3	38.9	419.4	1,210.7
18	102	3.4	30	3,129	297.2	890.3	9.5	221.9	58.1	50.1	675.3	1,905.2
19	162	5.4	30	6,255	297.2	1,434.9	15.1	353.5	92.4	50.1	1075.4	3,021.3
20	257	8.6	30	12,516	297.2	2,318.6	24.0	548.0	146.6	60.9	1709.5	4,807.6

TABLE 2-28

PACIFIC COAST (0 TO 200M WATER DEPTH)
GAS FIELD DEVELOPMENT COSTS
400 FOOT WATER DEPTH–8 MILES TO SHORE
(Millions of 1988 Dollars)

Field Size Class	# Wells	# Plat	Slots/ Plat	Resv (BCF)	Cost per Plat	Total Plat Costs	Plat Rig Mob	Gas Prod Eqpt	PV of Net Aband	Liq P/L	Prod Wells D&C	Total
1	1	1	4	0.02	25.3	25.3	0.3	1.5	0.6	0.0	0.9	28.6
2	1	1	4	0.05	25.3	25.3	0.3	2.2	0.6	0.0	0.9	29.4
3	1	1	4	0.10	25.3	25.3	0.3	3.0	0.6	0.0	0.9	30.1
4	1	1	4	0.19	25.3	25.3	0.3	3.9	0.6	0.0	0.9	31.0
5	1	1	4	0.38	25.3	25.3	0.3	5.3	0.6	0.0	0.9	32.4
6	1	1	4	0.76	25.3	25.3	0.3	7.0	0.6	0.0	0.9	34.2
7	1	1	4	1.5	25.3	25.3	0.3	9.5	0.6	0.0	0.9	36.6
8	1	1	4	3.1	25.3	25.3	0.3	12.7	0.6	0.0	1.5	40.4
9	2	1	4	6.1	25.3	25.3	0.3	16.9	0.7	0.0	2.8	46.1
10	2	1	4	12	25.3	25.3	1.4	22.7	0.8	0.0	5.1	55.2
11	4	1	6	24	27.5	27.5	1.4	30.3	0.9	2.1	9.5	71.8
12	7	1	8	49	29.8	29.8	1.4	40.6	1.2	2.1	18.1	93.3
13	12	1	16	98	38.6	38.6	1.4	54.4	1.7	2.1	32.8	131.0
14	19	1	20	195	43.0	43.0	2.8	69.7	2.4	2.1	53.2	173.2
15	31	1	32	391	56.3	56.3	2.8	88.8	3.6	2.1	86.0	239.6
16	49	2	26	790	49.6	99.3	5.6	168.5	6.0	2.1	138.9	420.4
17	77	3	26	1,564	49.6	148.9	8.4	266.3	9.3	3.0	219.4	655.3
18	123	5	26	3,129	49.6	248.2	14.0	443.9	14.9	3.9	351.7	1,076.6
19	196	7	30	6,255	54.1	378.4	19.6	657.2	23.3	3.9	561.7	1,644.1
20	312	11	30	12,516	54.1	594.6	30.8	1,013.0	37.0	4.8	895.3	2,575.4

TABLE 2-29

PACIFIC COAST (200 TO 2,000M WATER DEPTH) GAS FIELD DEVELOPMENT COSTS

(Millions of 1988 Dollars)

Field Size Class	# Wells	# Plat	Slots/ Plat	Resv (BCF)	Cost per Plat	Total Plat Costs	Plat Rig Mob	Gas Prod Eqpt	PV of Net Aband	Liq P/L	Prod Wells D&C	Total
1	1	1	NA	0.02	344.9	344.9	0.4	1.5	1.6	0.0	1.7	350.1
2	1	1	NA	0.05	344.9	344.9	0.4	2.2	1.6	0.0	1.7	350.8
3	1	1	NA	0.10	344.9	344.9	0.4	3.0	1.6	0.0	1.7	351.5
4	1	1	NA	0.19	344.9	344.9	0.4	3.9	1.6	0.0	1.7	352.5
5	1	1	NA	0.38	344.9	344.9	0.4	5.3	1.6	0.0	1.7	353.8
6	1	1	NA	0.76	344.9	344.9	0.4	7.0	1.6	0.0	1.7	355.6
7	1	1	NA	1.53	344.9	344.9	0.4	9.5	1.6	0.0	1.7	358.0
8	1.2	1	NA	3.06	344.9	344.9	0.4	12.7	1.7	0.0	2.6	362.1
9	1.6	1	NA	6.12	344.9	344.9	0.4	16.9	1.9	0.0	4.9	369.0
10	1.8	1	NA	12.20	344.9	344.9	0.4	22.7	2.1	0.0	5.8	375.8
11	3.0	1	NA	24.4	346.9	346.9	0.4	30.3	2.9	6.7	13.0	400.2
12	5.8	1	NA	48.9	348.9	348.9	0.4	40.6	4.8	6.7	28.1	429.5
13	9.9	1	NA	97.7	357.0	357.0	0.4	54.4	7.5	6.7	51.0	476.9
14	15.7	1	NA	195.4	361.0	361.0	0.4	69.7	11.4	6.7	83.3	532.5
15	25.8	1	NA	391.4	373.1	373.1	0.4	88.8	18.2	9.5	138.8	628.7
16	40.4	1.5	NA	790	365.1	536.5	0.4	144.3	28.4	9.5	219.7	938.9
17	63.6	2.1	NA	1,564	377.2	748.5	0.4	215.6	44.5	13.5	348.5	1,371.1
18	102.0	3.0	NA	3,129	397.4	1099.0	0.4	326.9	71.1	17.4	561.1	2,075.8
19	162.0	5.0	NA	6,255	385.2	1775.5	0.4	538.5	113.1	17.4	893.6	3,338.5
20	257.2	7.8	NA	12,516	391.3	2796.1	0.4	827.7	179.4	21.2	1420.5	5,245.2

Based on 30:70 weighting of conventional jacket in 1,350-foot water depth and tension leg platform in 4,500 foot water depth.

TABLE 2-30

GULF OF MEXICO—NORPHLET
GAS FIELD DEVELOPMENT COSTS
40 FOOT WATER DEPTH–30 MILES TO SHORE
(Millions of 1988 Dollars)

Field Size Class	# Wells	# Plat	Slots/ Plat	Resv (BCF)	Cost per Plat	Total Plat Costs	Plat Rig Mob	Gas Prod Eqpt	PV of Net Aband	Liq P/L	Prod Wells D&C	Total
1	1	1	1	0.02	3.8	3.8	0.3	1.4	0.4	0.0	5.0	10.8
2	1	1	1	0.05	3.8	3.8	0.3	2.1	0.4	0.0	5.0	11.5
3	1	1	1	0.10	3.8	3.8	0.3	2.8	0.4	0.0	5.0	12.2
4	1	1	1	0.19	3.8	3.8	0.3	3.7	0.4	0.0	5.0	13.1
5	1	1	1	0.38	3.8	3.8	0.3	4.9	0.4	0.0	5.0	14.3
6	1	1	1	0.76	3.8	3.8	0.3	6.6	0.4	0.0	5.0	16.0
7	1	1	1	1.5	3.8	3.8	0.3	8.9	0.4	0.0	5.0	18.2
8	1	1	1	3.1	3.8	3.8	0.3	11.9	0.4	0.0	5.0	34.0
9	1	1	1	6.1	3.8	3.8	0.3	15.9	0.4	0.0	5.0	38.0
10	1	1	1	12	3.8	3.8	0.3	21.2	0.4	0.0	5.0	48.9
11	1	1	1	24	3.8	3.8	0.3	28.4	0.4	12.8	5.0	74.1
12	1	1	2	49	4.0	4.0	0.3	38.1	0.4	12.8	10.0	94.1
13	2	1	2	98	4.0	4.0	0.3	51.0	0.4	12.8	18.3	120.3
14	3	1	4	195	4.6	4.6	1.4	65.3	0.5	12.8	30.5	158.3
15	5	1	6	391	5.2	5.2	1.4	83.3	0.6	12.8	56.6	212.4
16	8	2	4	790	4.6	9.2	2.8	158.0	1.1	12.8	105.9	351.6
17	15	3	6	1,564	5.2	15.5	4.2	249.6	1.9	18.3	207.4	572.1
18	28	4	8	3,129	5.7	23.0	5.6	365.7	3.0	23.5	395.9	905.0
19	46	6	8	6,255	5.7	34.4	8.4	563.5	4.8	23.5	656.9	1,366.8
20	76	10	8	12,516	5.7	57.4	14.0	898.7	7.9	28.6	1,091.9	2,186.8

cost in dollars per million BTU of marketable gas. Costs applied to production from new fields and field appreciation are shown in Table 2-32.

Other cost items contained in the Hydrocarbon Supply Model were developed from expenditure data contained in the annual Census Survey of oil and gas producers. Fifteen years of published data (1974-1988) were analyzed to develop cost estimates. Leasehold costs, exclusive of lease bonuses, include geological and geophysical surveys, scouting, and land rents. These costs are estimated to be 50 percent of the direct exploratory well costs from analysis of the Census data.

Onshore lease bonus costs are detailed by region in dollars per exploratory well. The lease bonus costs for the onshore area in the Census data (calculated simply as expenditures in a year divided by exploratory wells in that year) ranged from $165,000 to $345,000 (1988$) per exploratory well. The average lease bonus over the period investigated was $216,000.

Overhead costs are computed as a percentage of direct investment costs (wells plus equipment). Analysis of historical expenditures reported by the Census Bureau and API in the annual Survey of Oil and Gas Expenditures over the last 15 years determined that general and administrative expenses plus direct overhead rates have averaged 16 percent of well plus equipment costs over the last 15 years.

TABLE 2-31

ANNUAL OPERATING AND MAINTENANCE COSTS FOR ONSHORE GAS WELLS
(Thousands of 1988 Dollars)

	Region	Depth 1 0-5,000 ft	Depth 2 5-10,000 ft	Depth 3 10-15,000 ft	Depth 4 >15,000 ft
A	East	6	10	24	28
B	FL, MS, AL	12	20	24	28
C	Midwest	12	20	24	28
D	N. LA, N.E. TX, AR	12	20	24	28
E	S. LA Onshore	12	20	24	28
G	S. TX Onshore	12	20	24	28
WL	Williston Basin	15	24	29	32
FR	Foreland	15	24	29	32
SJB	San Juan Basin	15	24	29	32
OV	Western Thrust Belt	15	24	29	32
JN	Midcontinent	12	20	24	28
JS	Permian Basin	12	20	24	28
L	Pacific Coast Onshore	12	20	24	28

TABLE 2-32

COST OF NON-HYDROCARBON GAS REMOVAL
(1988 Dollars Per Million BTU of Marketed Gas)

Region	Depth	Cost
B: MAFLA Onshore	>15,000 Feet	$0.16
D: Arkla, Texas	>10,000 Feet	$0.06
FR: Foreland Basins	>15,000 Feet	$0.37
JS: Permian	>15,000 Feet	$0.05
NOR: Norphlet Trend	All	$0.52

Offshore Operating Costs

Typical platform operating costs assumed for the Gulf of Mexico and the Pacific are shown in Table 2-33. The costs for the two shelf depths are taken from an annual estimate of shallow-water oil and gas operating costs published by EIA. Costs have been estimated per platform and translated into a per well estimate based on average platform size. The EIA costs were adjusted for inflation and to more closely match the "typical" parameters for each offshore area as discussed earlier.

For the Gulf of Mexico slope interval, transportation and communication costs were estimated by extrapolation from the shelf area to account for longer distances to shore. Estimates of the cost of equipment and supplies and well workovers on tension leg platforms were assumed to be roughly the same per well as for a conventional platform. Annual insurance costs were estimated as one percent of the platform structure costs.

The cost of inspecting, repairing, and periodically replacing the anchoring and riser systems that connect tension-leg platforms to the sea floor are assumed to be 10 percent of the estimated initial costs for the mooring and risers.

Periodic replacement of the expensive corrosion resistant alloy tubing in Norphlet wells is added to operating costs in the offshore Norphlet. An annualized cost per well of $0.52 per million BTU has also been added for Norphlet wells to reflect the costs of hydrogen sulfide removal.

Offshore geological and geophysical investments are estimated in the same manner as onshore. Fifty percent of exploratory well costs are added as geological and geophysical investments.

Offshore lease bonuses are calculated as 60 percent of the net present value of a field's discounted cash flow without the bonus payment. Historically, the range for the lower-48 offshore is $1.1 to $24.9 million with an average of $3.8 million per offshore exploratory well (1988$).

General administrative plus overhead costs are represented as a fraction of direct exploratory, development well, and equipment

TABLE 2-33

ANNUAL OPERATING COSTS FOR PRODUCTION PLATFORMS
(Thousands of 1988 Dollars)

Typical water depth	**75 ft.**	**400 ft.**	**1,350 ft.**	**4,500 ft.**	**40 ft.**
Platform type	**Steel Jacket**	**Steel Jacket**	**Steel Jacket**	**TLP**	**Norphlet**
Wells	**18**	**18**	**18**	**20**	**4**
Labor, supervision, payroll, overhead, food	899	899	899	899	200
Administration	256	256	256	256	57
Labor transportation	369	414	465	522	82
Communications	16	32	48	64	4
Operating equipment and supplies	95	106	116	127	63
Maintenance and replacement of moorings and risers	—	—	—	3,000	—
Well workover	674	702	731	761	449
Insurance	370	401	435	2,970	247
Total	**2,679**	**2,810**	**2,950**	**8,599**	**1,102**
Cost Per Well/Year	149	156	164	430	575
Pacific Coast Cost Per Well/Year	191		220		

costs. Offshore overhead is applied to offshore investments in the same manner as onshore.

ECONOMIC ASSUMPTIONS

Rate of Return on Investments

The Hydrocarbon Supply Model attempts to replicate the decision-making process used by producers in determining the annual level of exploration and development activity that will take place in each supply region. Of the many assumptions required to do this, one of the criteria is the minimum real rate of return (ROR) required from the after-tax, discounted cash flow (DCF) analysis of a project.

In establishing the annual exploration program, an after-tax, DCF analysis is performed for potential exploration and production programs in each region/depth interval within the model. The HSM then selects which exploration programs will be undertaken, based upon a ranking by profit index and after considering any inertial and capital constraints imposed. The resulting exploration program is then carried out, yielding an inventory of discoveries for development. Another DCF analysis is then done for the discoveries to determine which of those developments would be economic.

This modeling approach appears to reasonably simulate the producer decision-making process utilized to establish exploration and production programs and budgets. However, since the model has perfect knowledge regarding the expected discoveries and cost of development and can thus accurately determine the precise economic ranking of exploration and development projects, it will tend to reflect a more optimal industry program than will occur in the real world.

Since the minimum ROR criteria utilized are rarely published, determining precisely what average industry minimum ROR should be used in the model is virtually impossible. Most companies actually use minimum RORs or "hurdle rates" as a means of influencing the overall return of the company or business segment rather than as the sole criteria for investment decisions. It is appropriate to consider the minimum ROR as strictly one of the input variables to be utilized to logically sequence activity and control the appropriate long-term target average industry return.

Shell Oil Company recently released a study of industry profitability entitled *Profitability Study: Crude Oil and Natural Gas Exploration, Development, and Production Activities in the United States, 1959-88*, which analyzed average exploration and production returns over a 30-year period. The two primary conclusions from the study are: (1) the exploration and production industry has historically invested in projects that yield an average real ROR of about 5 percent, and (2) the profitability of the exploration and production industry during the 1980s has been at an all-time low.

Based upon these conclusions, it would be reasonable to deduce that if the industry continues to make investment decisions based on similar criteria as used historically, future investments should result in an average real ROR in the range of 5 percent given a relatively stable and predictable future economic environment. However, as a result of the past few years of extremely disappointing financial results and retrenchment by the industry, it is not unreasonable to conclude that the industry will be much more conservative in the investments undertaken during the 1990s and possibly much longer. With this premise, it would seem logical to expect the average industry ROR from the model to be somewhat higher than the historical 5 percent shown in the Shell study, at least in the near term.

Reinvestment Ratio

The logic within the HSM for selecting investment opportunities to pursue includes a check on the amount of cash available to industry for reinvesting. Input specifications allow a limit to be placed upon the amount of available cash that is actually reinvested by industry. The criteria is that the sum of all operating costs and capital expenditures (exploration and production) will not exceed a user-specified fraction of the previous year's net revenues (gross revenue less severance taxes and royalties).

A 1986 Arthur Andersen study of 375 public companies, *Oil & Gas Disclosures*, indicates that during the 1981 to 1985 period, this reinvestment ratio (excluding property acquisitions) averaged 68 percent, declining from 80

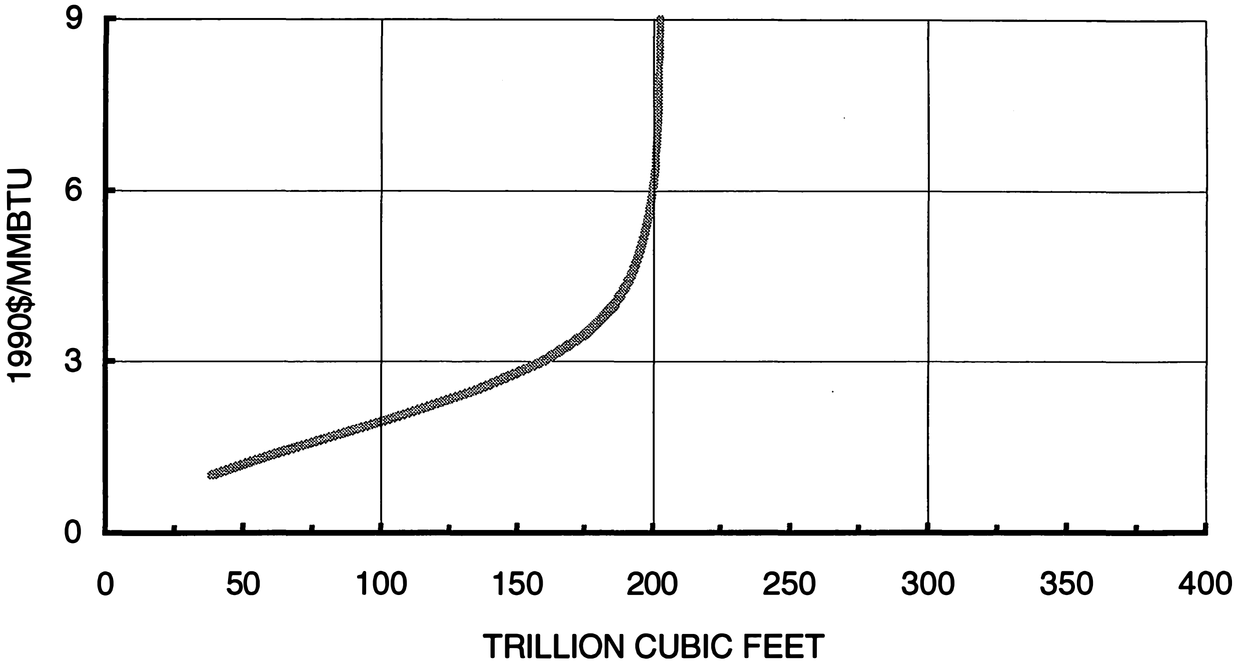

Figure 2-5. U.S. Lower-48 Resource Cost Curve with Advanced Technology — Conventional Gas Reserve Appreciation.
(Non-Associated and Associated/Dissolved Gas)

percent in 1981 to 60 percent in 1985. For the NPC study, no limit was specified as the results were felt to be reasonable.

Resource Cost Curve

A way of depicting the resource base in terms of its economic potential is through the use of a "resource cost curve." Such a curve portrays the wellhead gas price required to develop a certain amount of the resource base and yield the minimum rate of return to the investor. Figure 2-5 shows the resource cost curve for the reserve appreciation resource that was detailed in Table 2-4.

The reserve appreciation resource is the most economical resource in the inventory since it is already within the confines of known fields and therefore requires only a moderate amount of exploration (such as outpost wells) and most of the infrastructure already exists. Figure 2-5 shows that about 80 percent of the resource can be developed at a price of $3.00 per MCF (1990$).

Figure 2-6 shows the resource cost curve for the undiscovered conventional gas resource base that is detailed in Table 2-9. All of the cost and development assumptions are combined with the resource base and the economic assumptions to develop Figure 2-6.

This curve shows that about a third of the 493 TCF of undiscovered resource (including tight gas in old plays) can be economically developed at a price of $3.00 per MCF (1990$) assuming advanced technology.

The interpretation of a resource cost curve must be done very carefully. The price indicated in Figure 2-6 is a constant price whereas actual price paths will not be constant. Furthermore, although the graph shows that about 175 TCF of gas is economic at a price of $3.00 per MCF, it obviously will not become available all at once because of time lags in exploration and development and inertial constraints, which limit how fast industry can change its level of activity.

DEVELOPMENT ASSUMPTIONS

The pattern of field development (i.e., the number and timing of production wells drilled in a field) and the deliverability/production profiles for new fields are important items in the

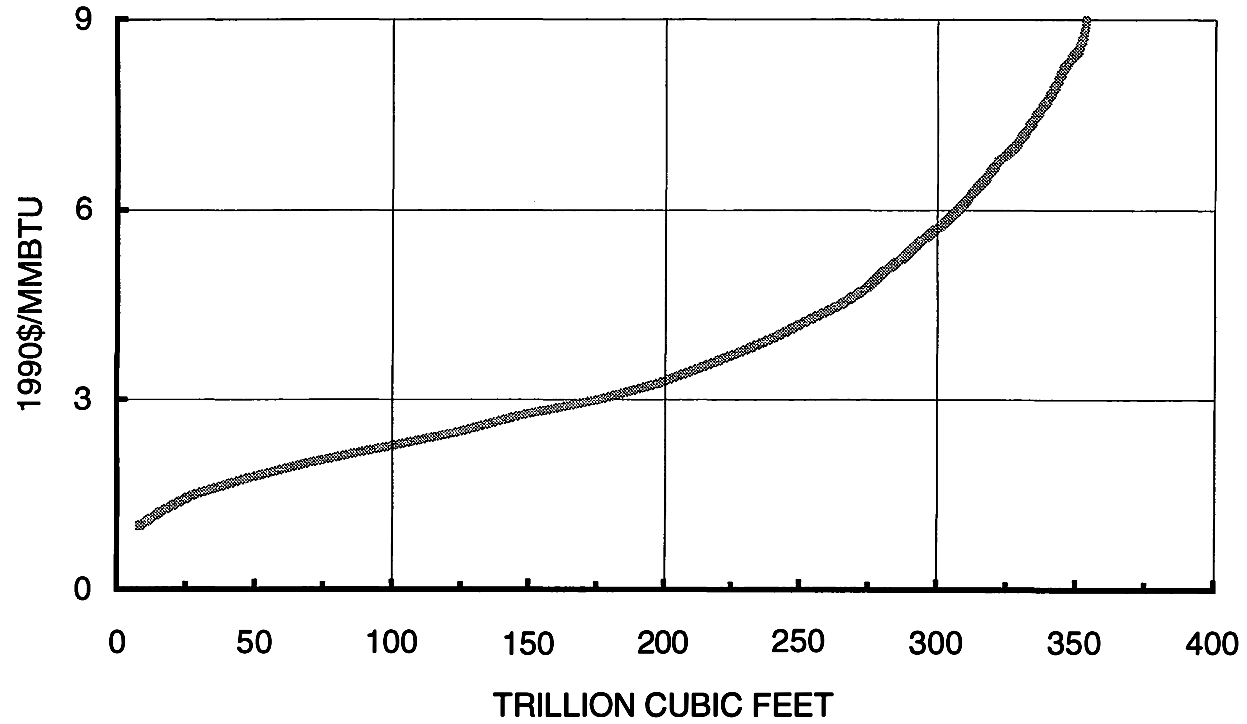

Figure 2-6. U.S. Lower-48 Resource Cost Curve with Advanced Technology — Conventional Gas Undiscovered Resource.

(Includes Tight Gas in Old Plays)

economic analysis of exploration and/or development opportunities. The number and timing of production wells determine the development costs for fields, while the deliverability/production profiles help determine the revenue stream a producer can expect from developing a field.

Gas fields are treated differently from oil fields in that, once production capacity is installed, it is not assumed that production will take place at the maximum rate. Production from gas fields will vary depending upon the regional demand for gas.

As discussed earlier, reserves are proved in a field over a period that can last several years. The major reason for this pattern of increasing reserves is that the physical dimensions of the field are enlarged as new reservoirs are discovered and the boundaries of known reservoirs are expanded. Within the Hydrocarbon Supply Model, it is assumed that development activity usually coincides with the process by which reserves are proved. In other words, if 35 percent of the reserves in a field are proved in the first year then 35 percent of the development drilling needed for the field will occur in the first year with a similar assumption until the field is fully proved. This general pattern applies to both oil and gas fields in onshore regions. The pattern is usually somewhat different for offshore areas where development drilling often must await construction of a production platform.

Production/deliverability profiles for single wells vary by region, depth, and the size of the field in which the wells are drilled. The production/deliverability profiles for an entire field are found by summing the profiles of all wells producing from a block of reserves proved in any year and then summing across the blocks to get the field total.

For gas wells, annual deliverability is specified as a hyperbolic decline function. Because gas wells are not necessarily produced at 100 percent of deliverability (or any other fixed level) over the life of the well, annual deliverability is estimated as a function of cumulative production. The decline curve equations were developed from analyses of historical production data from the Dwight's Gas Well Reports.

The number of producing wells in a field was estimated from analysis of historical data.

The number of development wells added to a field is the total number of producing wells minus the number of exploratory wells expected to be completed as producers in the field. For onshore fields, this number of producing exploratory wells is estimated as one per 2,560 acres (four square miles) of the typical areal extent of each size class. There must be at least one producing exploratory well for each onshore field (i.e., the new field wildcat that found the field). For offshore areas, only one producing exploratory well is assumed for any field because offshore exploratory wells typically are drilled from mobile drilling rigs and are not completed, except for the well located directly at the fixed production platform.

References for Development Assumptions

American Petroleum Institute, *Joint Association Survey on Drilling Costs*, Washington, D.C., several years.

U.S. Department of Energy, Energy Information Administration, *Costs and Indexes for Domestic Oil and Gas Field Equipment and Production Operations*, DOE/EIA-0185, several years.

American Petroleum Institute, *Survey on Oil and Gas Expenditures*, several years.

E. D. Attanasi and J. L. Haynes, "Future Supply of Oil and Gas from the Gulf of Mexico," U.S. Geological Survey Professional Paper 1204, Washington, D.C., 1983.

RESULTS

The conventional gas resource base in the lower-48 states plays an important part in supplying gas to meet future demand. Although it is only a part of the gas supply, it does play a very major role. The results of the two Reference Cases for the NPC gas study are presented elsewhere for the total resource base, while this chapter is limited to discussing the results for the conventional gas resource base. In all of the results that follow, associated/dissolved gas and conventional non-associated gas are added together to represent total conventional gas.

The results of the overall model runs for the two cases are first presented in terms of the average Gulf Coast wellhead gas price in Figure 2-7. Although the gas price predictions shown in Figure 2-7 are the result of balancing supply and demand rather than an estimate or forecast that is used to determine supply, the price path can be used to explain the character of the supply results for a specific segment—in this case, the conventional gas segment.

Figure 2-8 shows the expected conventional gas development drilling activity for the two cases. Reference Case 1 shows that the gas price growth during the 1990s is sufficient to spur increased conventional gas drilling activity whereas Reference Case 2 shows a predictable decline in gas drilling during the first half of the 1990s due to the very slow growth in gas prices.

Figure 2-9 shows production and reserve additions for Reference Case 1.

Due to the escalating prices in the first half of the period, reserve additions from the conventional gas resource show a substantially increasing trend. However, it is not until about 2000 that reserve additions replace production. This declining proved reserves base (as seen in Figure 2-10) causes the gradually decreasing conventional gas production trend.

The decrease in annual conventional gas reserve additions (Figure 2-9) after 2004 despite increasing gas prices and the corresponding decline in proved reserves (Figure 2-10) reflect the maturity of the resource base. Although it is large, the remaining portion of the conventional gas resource base is generally in smaller fields and/or deeper horizons, all of which makes for more costly gas. Figure 2-10 shows that shortly after 2000, total proved gas reserves begin to increase annually, while conventional gas proved reserves begin to decline after 2005. This is an indication that nonconventional gas is becoming the marginal supply source as the conventional gas resource base matures. Overall, the total gas resource base is of sufficient size that forecast demand can be met with the prices shown in Figure 2-7. The increasing inventory of proved reserves post-2000 is a market driven response to higher levels of gas demand.

Figure 2-11 shows the production and reserve addition estimates for Reference Case 2. The slower gas price growth during the 1990s is reflected in the reserve additions estimated for Reference Case 2. The resulting proved reserves

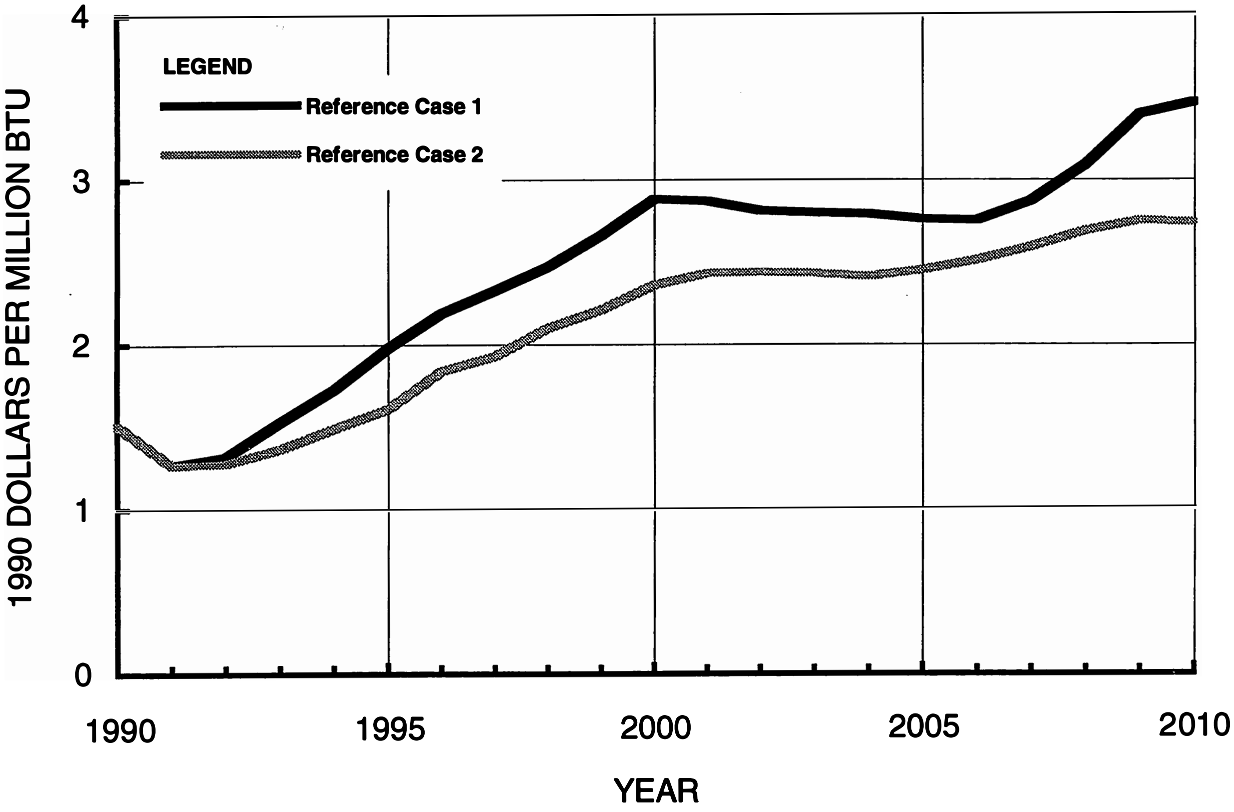

Figure 2-7. Average Gulf Coast Wellhead Gas Price.

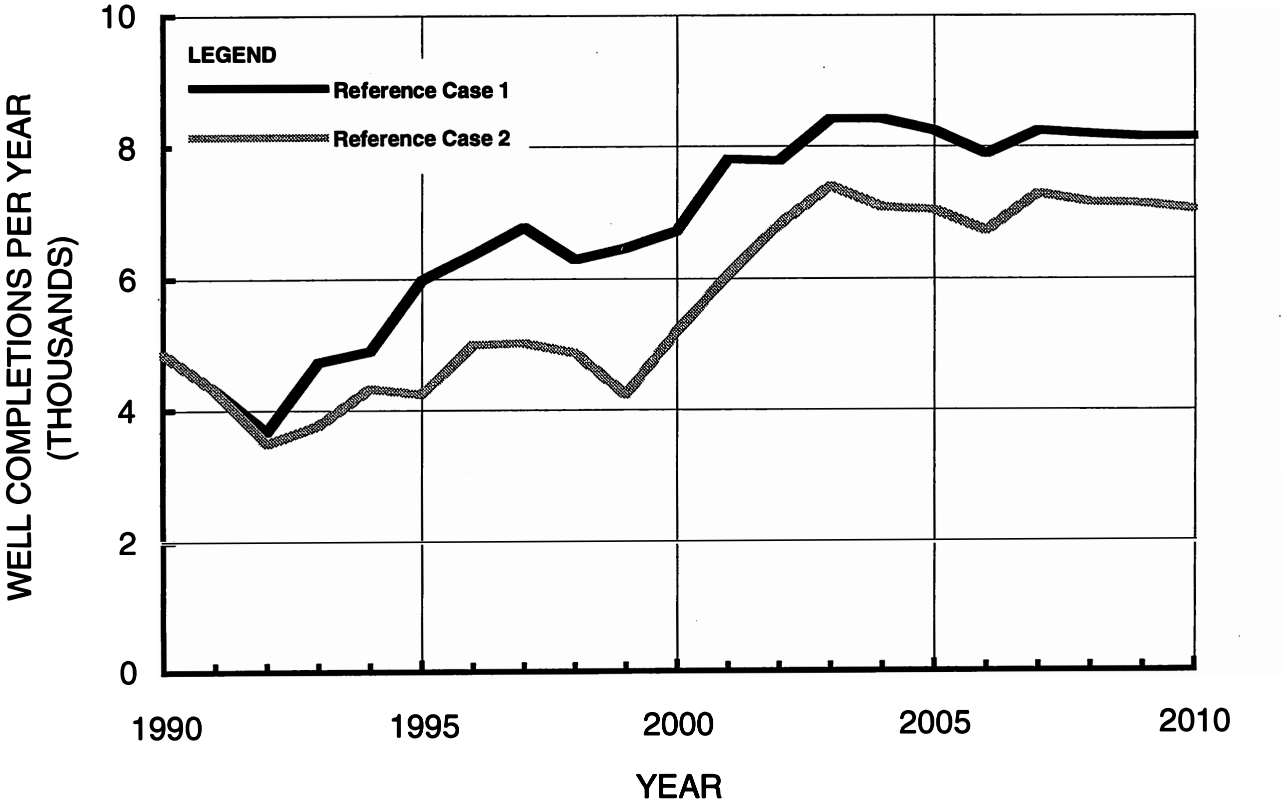

Figure 2-8. Conventional Gas Well Completions — U.S. Lower-48.

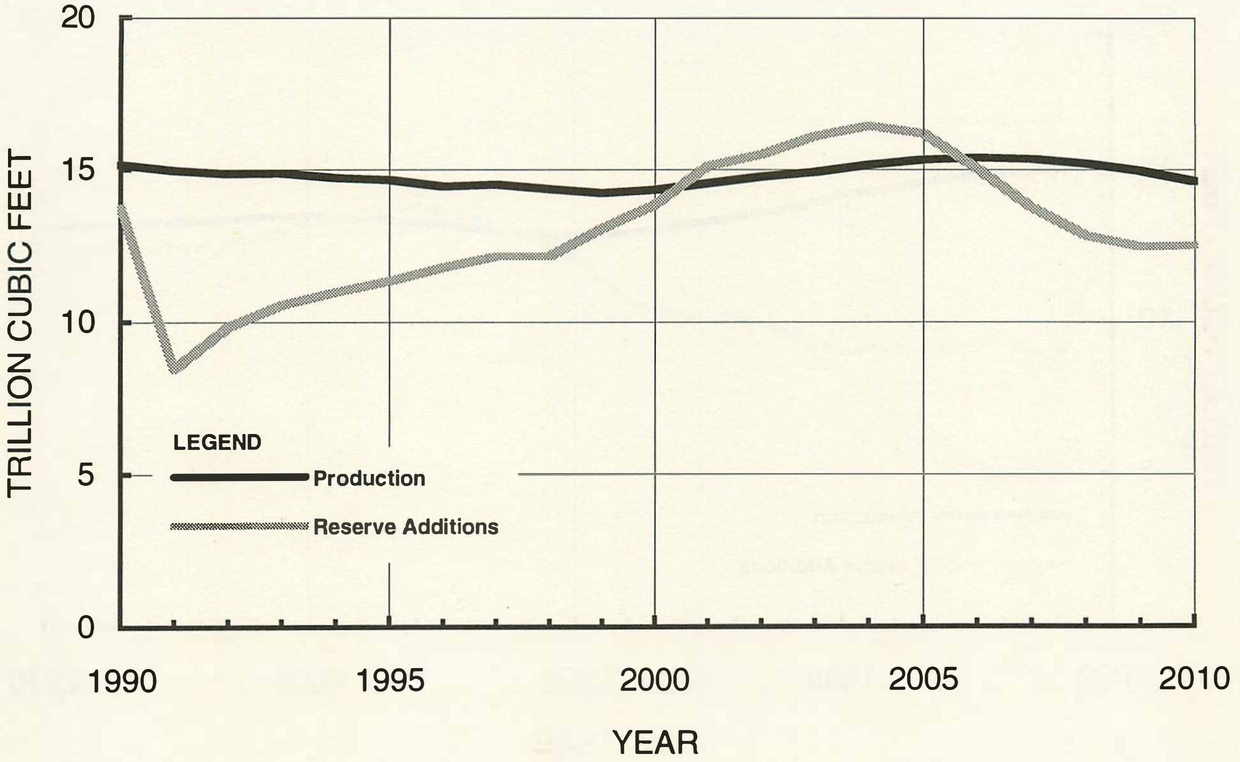

Figure 2-9. Conventional Gas Production and Reserve Additions in the U.S. Lower-48 — Reference Case 1.

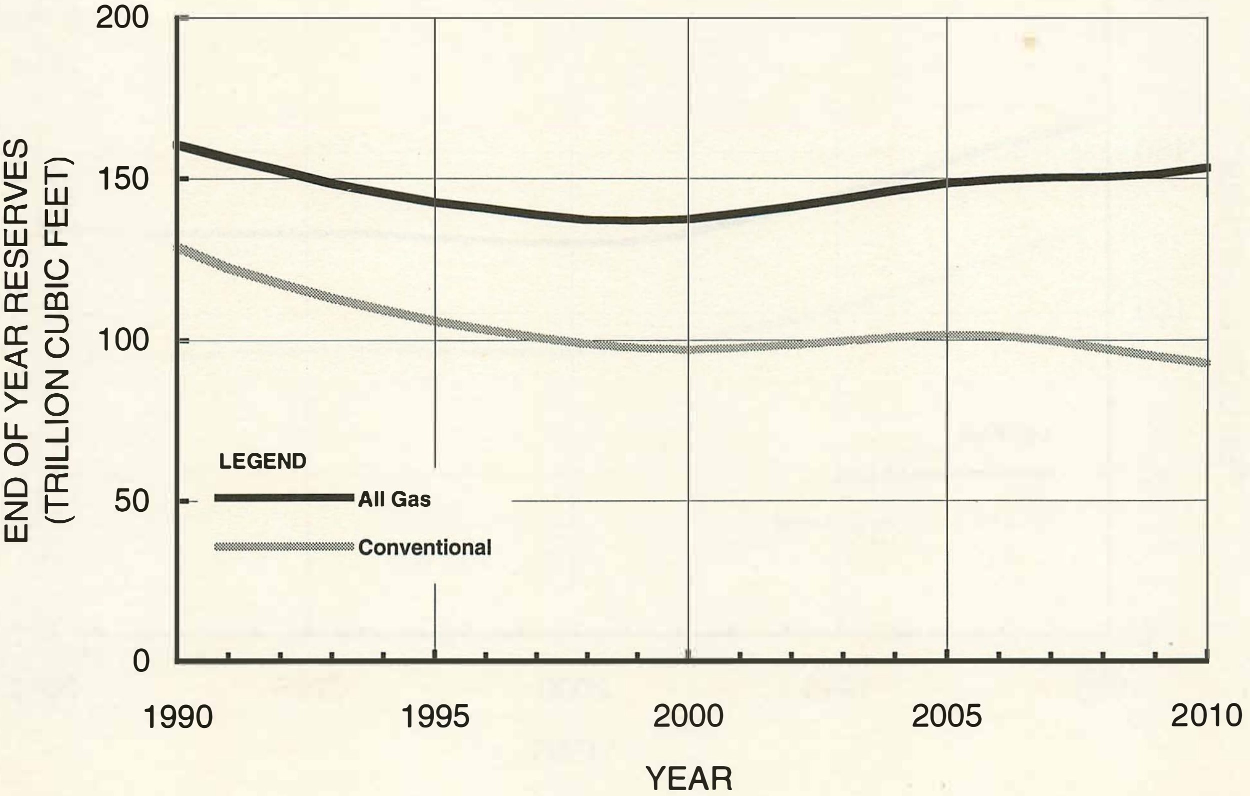

Figure 2-10. Proved Reserves in the U.S. Lower-48 — Reference Case 1.

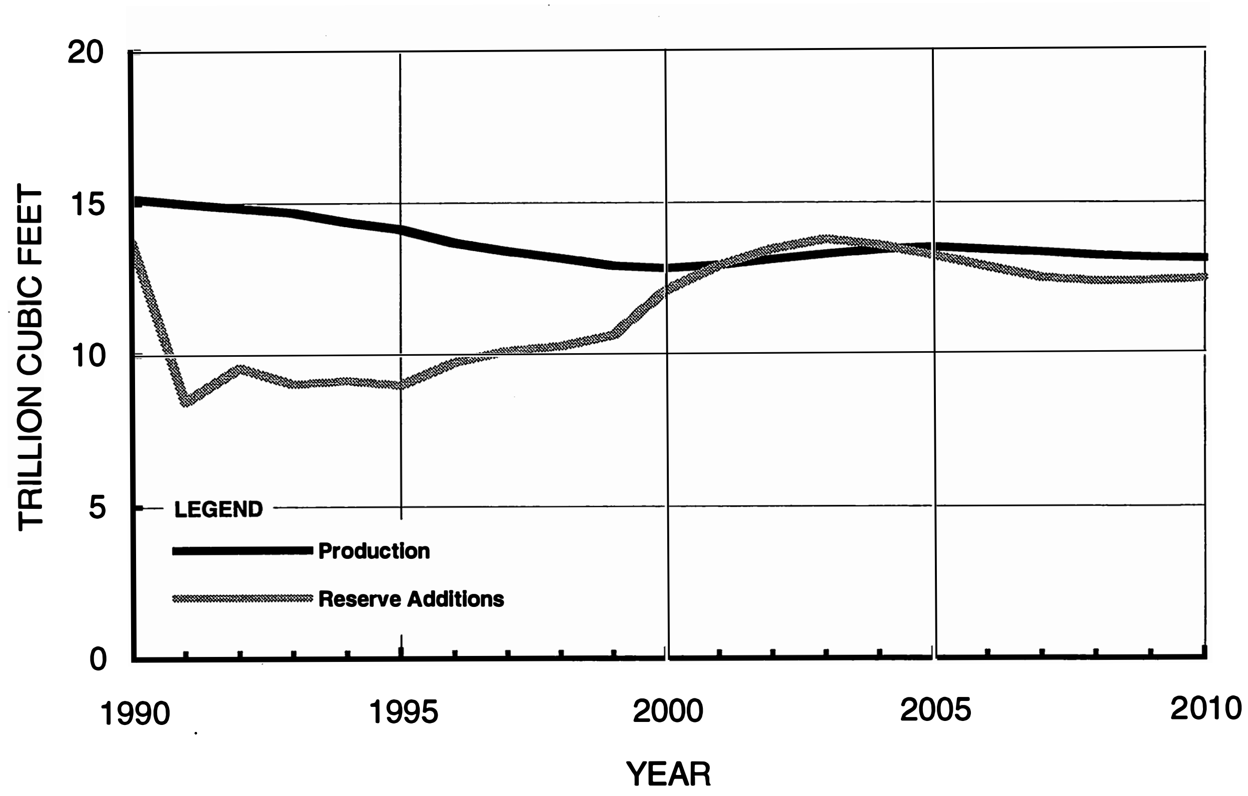

Figure 2-11. Conventional Gas Production and Reserve Additions in the U.S. Lower-48 — Reference Case 2.

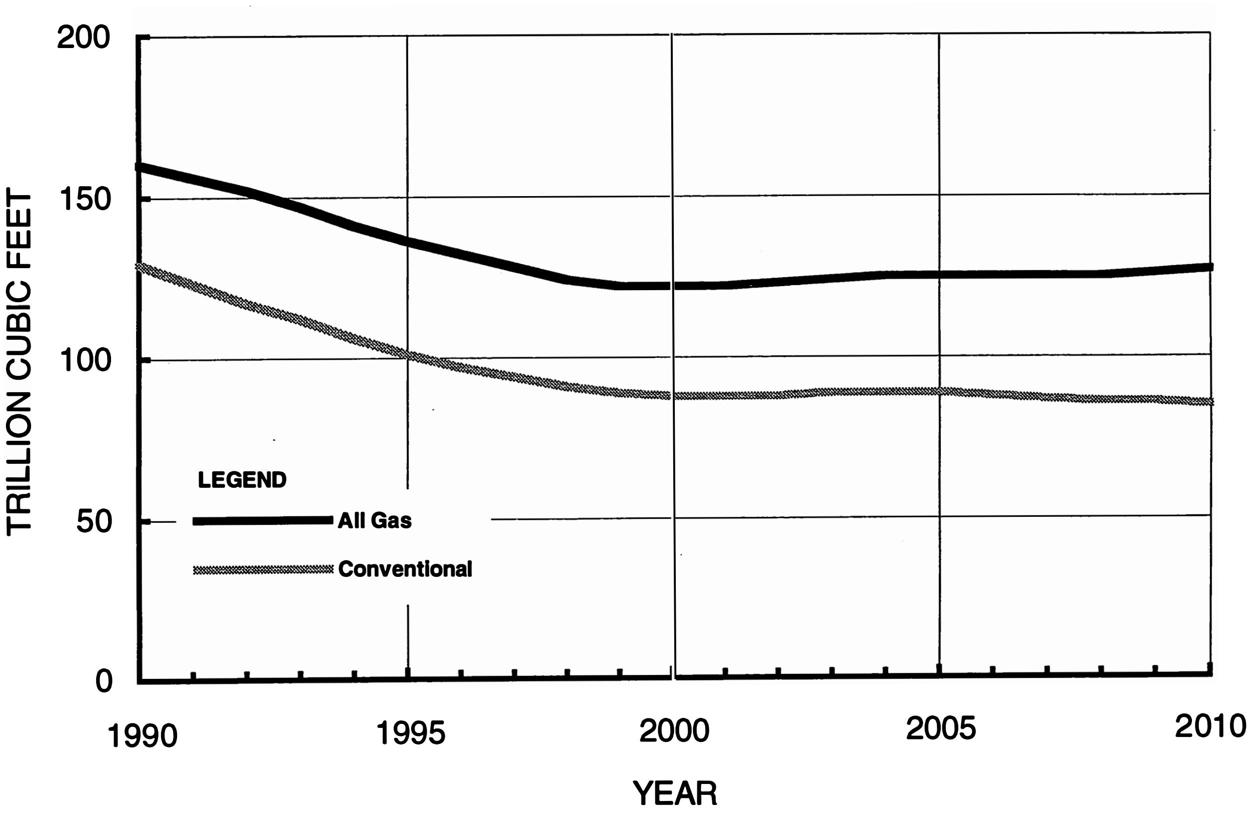

Figure 2-12. Proved Reserves in the U.S. Lower-48 — Reference Case 2.

are shown in Figure 2-12. In this case, the contribution of conventional gas to the total proved reserve base is more significant than in Reference Case 1. This is because the lower price path does not stimulate the development of nonconventional resources as fast as in Case 1. The lower demand for gas post-2000 results in the lower inventory of proved reserves in Case 2.

SENSITIVITIES

One of the most significant areas of uncertainty in the conventional gas portion of this study revolves around the estimate of the undiscovered resource base. Whether the estimation process is a statistical analysis of past exploration results, represents a consensus estimate of a group of experts, or is a detailed geologically based play analysis, there will likely be a fairly large uncertainty as to the size of the resource base. In order to test the impact of this uncertainty upon such parameters as gas price, production, and reserve additions, sensitivities to higher and lower conventional gas resource base estimates were done.

The same NPC working group that did the assessment of the size of the resource base for the reference cases assessed the possible upside and downside ranges for each of the areas

TABLE 2-34

1-1-91 UNDISCOVERED GAS RESOURCE BASE
CURRENT TECHNOLOGY
HIGH SIDE SENSITIVITY
(INCLUDES TIGHT GAS IN ACTIVE AREAS)
(Billion Cubic Feet)

Region		0-5,000'	5-10,000'	10-15,000'	>15,000'	Total
Appalachia	A	6,216	10,288	11,916	5,279	33,699
MAFLA Onshore	B	854	357	5,468	7,809	14,488
Midwest	C	2,157	3,900	6,923	0	12,980
Arkla-E. Texas	D	3,843	7,198	6,165	1,317	18,523
So. Louisiana	E	0	557	2,319	22,319	25,195
Texas Gulf Coast	G	2,503	16,312	19,050	8,176	46,041
Williston	WL	946	1,199	447	0	2,592
Rockies Foreland	FR	3,577	16,449	19,742	32,818	72,586
San Juan Basin	SJB	1,170	1,981	0	0	3,151
Overthrust	OV	300	3,791	9,198	4,370	17,659
Midcontinent	JN	4,819	12,416	18,927	21,885	58,047
Permian	JS	3,586	6,202	4,598	20,328	34,714
Pacific	L	1,446	6,727	5,099	4,258	17,530
Subtotal Onshore		**31,417**	**87,377**	**109,852**	**128,559**	**357,205**
				Subregion		
		1	**2**	**3**	**4**	**Total**
Norphlet	BO	11,388				11,388
West Florida						2,590
Gulf of Mexico	EGO	25,311	23,122	36,642	36,402	121,477
Pacific Offshore	LO	2,807		10,204		13,011
Atlantic Offshore	AO					34,026
Subtotal Offshore						**182,492**
Grand Total						**539,697**

Note: Values are recoverable hydrocarbons as of 12-31-90; Subregions for BO, EGO are <40m, 40-200m, 200-1000m, and >1000m water depth; LO is 0-200m and 200-2000m; AO and West Florida have no defined water depth.

TABLE 2-35

1-1-91 UNDISCOVERED GAS RESOURCE BASE
CURRENT TECHNOLOGY
LOW SIDE SENSITIVITY
(INCLUDES TIGHT GAS IN ACTIVE AREAS)
(Billion Cubic Feet)

Region		**0-5,000'**	**5-10,000'**	**10-15,000'**	**>15,000'**	**Total**
Appalachia	A	6,216	10,288	4,926	2,159	23,589
MAFLA Onshore	B	854	357	5,468	4,229	10,908
Midwest	C	2,157	3,900	2,423	0	8,480
Arkla-E. Texas	D	3,843	7,198	6,165	1,317	18,523
So. Louisiana	E	0	557	2,319	12,319	15,195
Texas Gulf Coast	G	2,503	16,312	11,000	8,176	37,991
Williston	WL	946	1,199	447	0	2,592
Rockies Foreland	FR	3,577	16,449	12,221	16,351	48,598
San Juan Basin	SJB	719	1,303	0	0	2,022
Overthrust	OV	300	3,791	3,748	4,370	12,209
Midcontinent	JN	4,819	12,416	11,659	15,458	44,352
Permian	JS	3,586	6,202	4,598	12,328	26,714
Pacific	L	1,446	3,267	2,479	1,998	9,190
Subtotal Onshore		**30,966**	**83,239**	**67,453**	**78,705**	**260,363**
				Subregion		
		1	**2**	**3**	**4**	**Total**
Norphlet	BO	11,388				11,388
West Florida						2,590
Gulf of Mexico	EGO	18,911	15,712	15,722	36,402	86,747
Pacific Offshore	LO	2,807		4,454		7,261
Atlantic Offshore	AO					17,013
Subtotal Offshore						**124,999**
Grand Total						**385,362**

Note: Values are recoverable hydrocarbons as of 12-31-90; Subregions for BO, EGO are <40m, 40-200m, 200-1000m, and >1000m water depth; LO is 0-200m and 200-2000m; AO and West Florida have no defined water depth.

in the HSM. Table 2-34 shows the high side sensitivity for the resource base and Table 2-35 portrays the low side. Both of these tables can be compared to the reference case assessment of the resource base as detailed in Table 2-9. Note that both tables include the tight gas in active areas, since these are represented by the finding rate equations. The amount of tight gas in the tables is on the same ratio as Table 2-12 is to Table 2-9.

The reference case resource base estimate in Table 2-9 is 429 TCF. The High Side Sensitivity is 540 TCF, or 26 percent higher while the Low Side Sensitivity is 385 TCF, or 10 percent lower.

The impact of the sensitivity estimates of resource base size on gas prices is shown in Figure 2-13. The 10 percent lower estimate for the conventional gas (including tight gas in active areas) resource base could result in a gas price that reaches about 3 percent higher by 2010 than Reference Case 1. A 26 percent larger resource base could lower prices by 16 percent in 2010.

Conventional gas production comparisons for the two resource base sensitivities are shown in Figure 2-14. The smaller resource base and its slightly higher gas price could result in about 6 percent less conventional gas production in 2010 and a total of 8 TCF (3 percent) less being produced from 1992-2010. The larger resource base could result in about 15 percent more production in 2010 and 15 TCF (6 percent) more gas being produced from 1992-2010.

Reserve additions from conventional gas are impacted by the size of the resource base as shown in Figure 2-15. Reserve additions in 2010 are 11 percent lower than the reference case for the smaller resource base estimate with 12 TCF (6 percent) less additions during the 1992-2010 period. The larger resource base could provide 18 percent more reserve additions in 2010 than the reference case and 28 TCF (11 percent) more during the 1992-2010 time frame.

CONCLUSIONS

The following are the key findings from the work of the Conventional Gas Subgroup:

- The conventional gas undiscovered resource base is estimated to be 375 TCF, assuming today's technology, which includes 326 TCF of non-associated gas and 49 TCF of associated/dissolved gas. Assuming technological advances expected to be operationally viable by 2010, this resource base would grow to 413 TCF.
- The proved reserves of 160 TCF in existing fields will grow by an estimated 236 TCF in the future, assuming advanced technology. This represents the reserve appreciation resource base (and includes tight gas in old plays).
- The conventional gas resource base is large but is maturing. As a result of this maturation, conventional gas will supply a decreasing proportion of total lower-48 gas production and reserve additions in the future as nonconventional resources are increasingly exploited. Conventional gas production is expected to decline from 83 percent of lower-48 gas production in 1995 to 77 percent in 2010, while the conventional gas reserve additions will drop from 77 percent to 55 percent during the same period.
- The uncertainty in the estimate of the size of the undiscovered conventional gas resource base should not materially affect the outlook for gas supply through the 2010 time frame. Conventional gas production could vary by ± 10 percent if the resource base is under- or over-estimated by 20 percent.

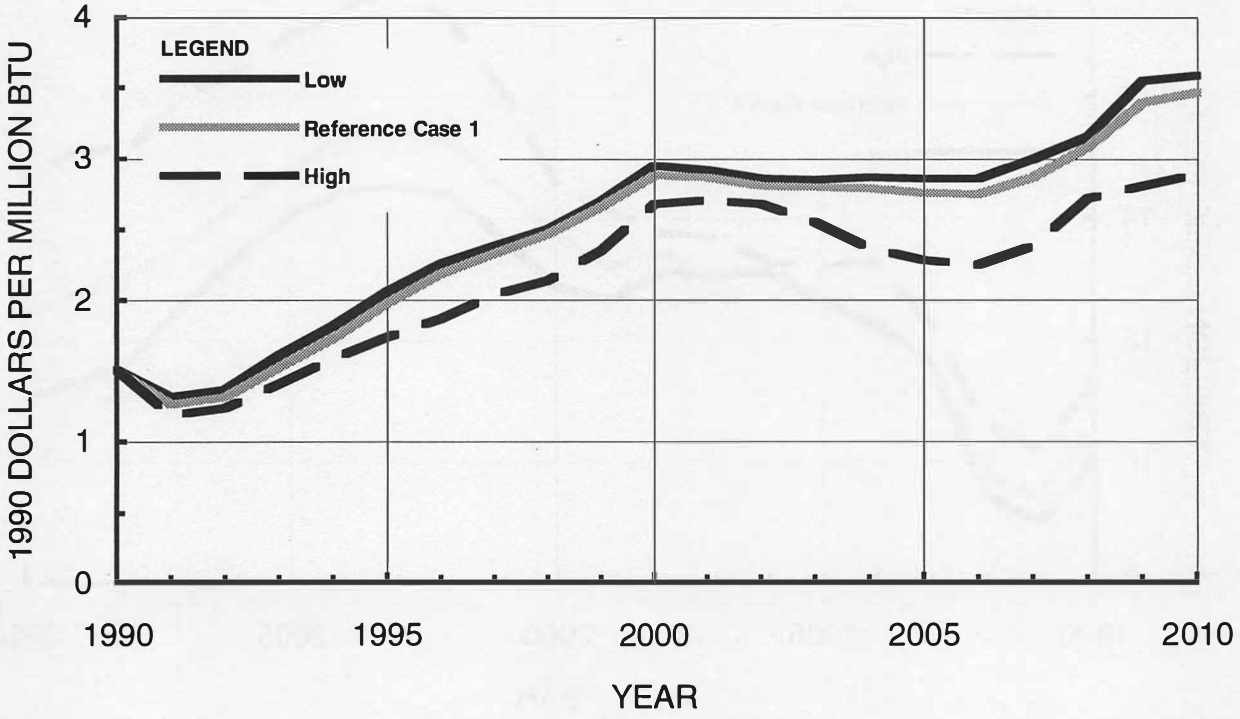

Figure 2-13. Conventional Gas Resource Base Sensitivities — Gas Price.

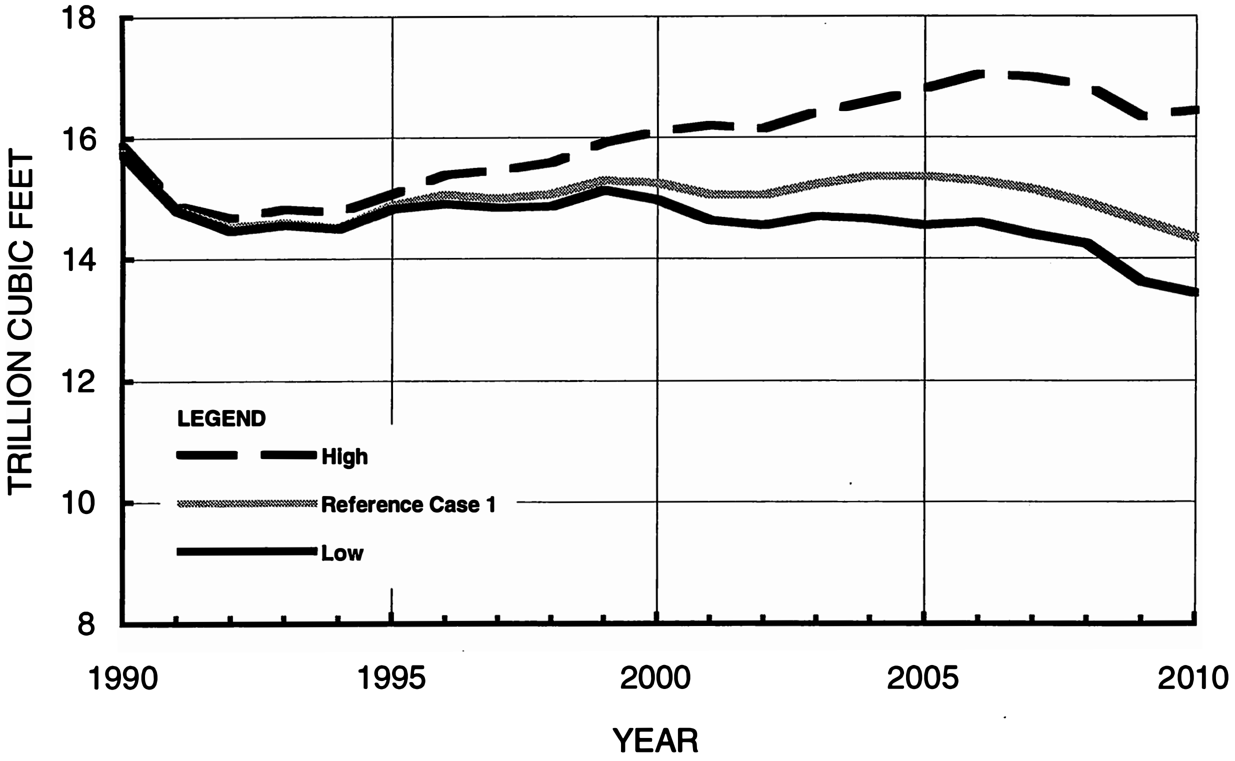

Figure 2-14. Conventional Gas Resource Base Sensitivities — Conventional Gas Production.

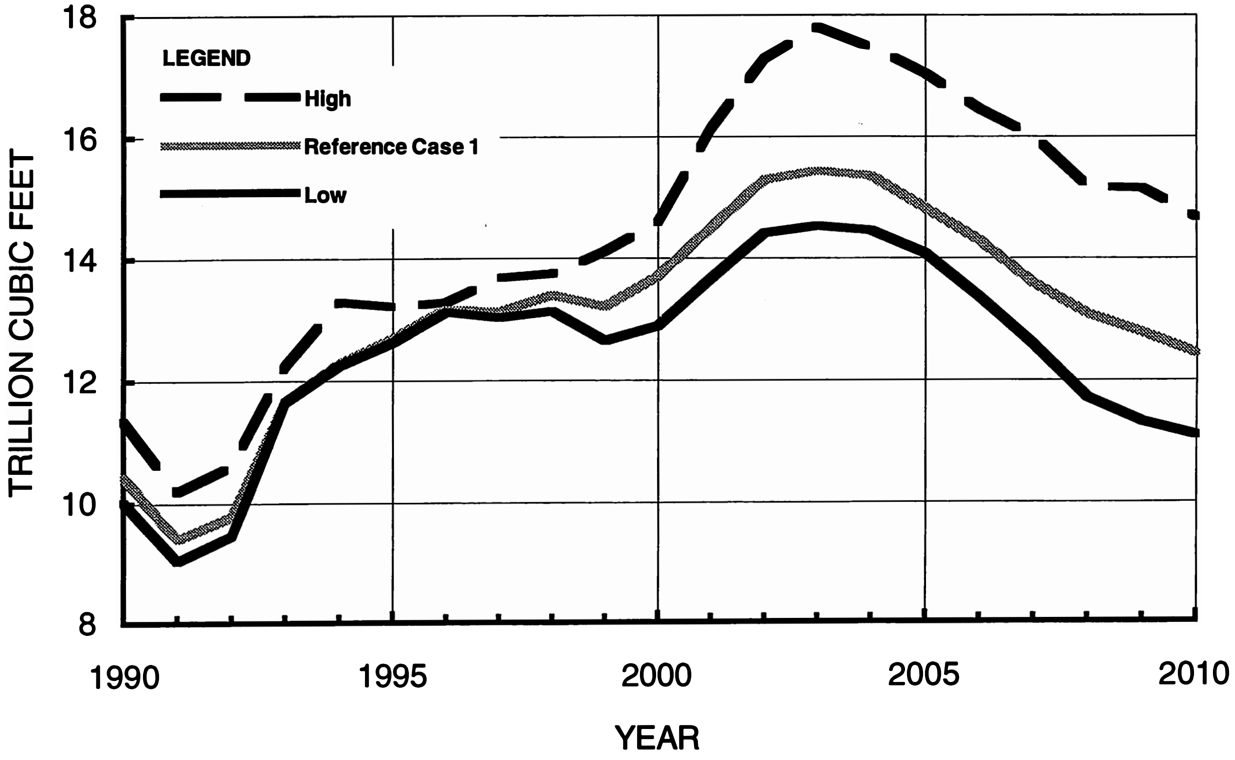

Figure 2-15. Conventional Gas Resource Base Sensitivities — Conventional Gas Reserve Additions.

CHAPTER THREE

NONCONVENTIONAL GAS SOURCES

SUMMARY

The principal nonconventional gas basins in the United States are shown in Figure 3-1. Tight gas resources occur in sedimentary basins throughout the United States, but only those basins having significant production potential in the next half-century have been evaluated in this study. About half of the resources estimated to be economically recoverable are in the Rocky Mountain region. The principal coalbed methane resources of commercial interest are in the San Juan, Appalachian, Black Warrior, and Piceance Basins, while gas from shales is produced primarily in the Appalachian and the Michigan Basins.

The Nonconventional Gas Subgroup was charged with establishing the recoverable resource base and reviewing the modeling of nonconventional gas in the Hydrocarbon Supply Model, which was used to establish the future supply potential for natural gas. These tasks were accomplished through subgroup work teams using information supplied by individual companies, and through consultant studies. The recoverable resource estimates recommended by the Nonconventional Gas Subgroup for modeling NPC Reference Cases 1 and 2 are shown in Table 3-1. Estimated recoverable resources of nonconventional gas are 332 trillion cubic feet (TCF) using current technology. Factoring in anticipated advances in technology, recoverable resources are estimated to increase to 504 TCF in 2010. The tight gas recoverable resources make up about 70 percent of the total nonconventional gas resources, and 25 to 30 percent of all remaining U.S. undiscovered recoverable gas resources.

Low British thermal unit (BTU) gas along the Moxa Arch in the Green River Basin of Wyoming is also represented in the Hydrocarbon Model. The low BTU gas is in a single massive reservoir containing 170 TCF of raw gas, which consists mostly of carbon dioxide but contains up to 22 percent methane. Recoverable resources of methane in the gas are estimated at 15 TCF with either current or advanced technology. Production and reserve additions projected in model runs for this resource are classified as "Enhanced Recovery Gas" and are included in "conventional" production.

Nonconventional gas production predicted by the Hydrocarbon Model in the two NPC Reference Cases is shown in Table 3-2. In 1990, about 1.7 TCF of tight gas was produced in the lower 48 states, plus about 0.2 TCF from Devonian/Antrim shale and 0.2 TCF of coalbed methane. In Reference Case 1, the moderate energy growth scenario, modeled tight gas production increases to about 2.0 TCF in 2000. Devonian/Antrim shale gas increases to 0.5 TCF, and coalbed methane to 1.1 TCF in that year. In 2010, modeled tight gas production increases to 3.7 TCF, with Devonian/Antrim shale and coalbed methane production projected at 0.5 and 1.3 TCF, respectively.

Total nonconventional gas production in Reference Case 1 increases from 2.1 TCF in 1990 to 3.6 TCF in 2000 and to 5.5 TCF in 2010.

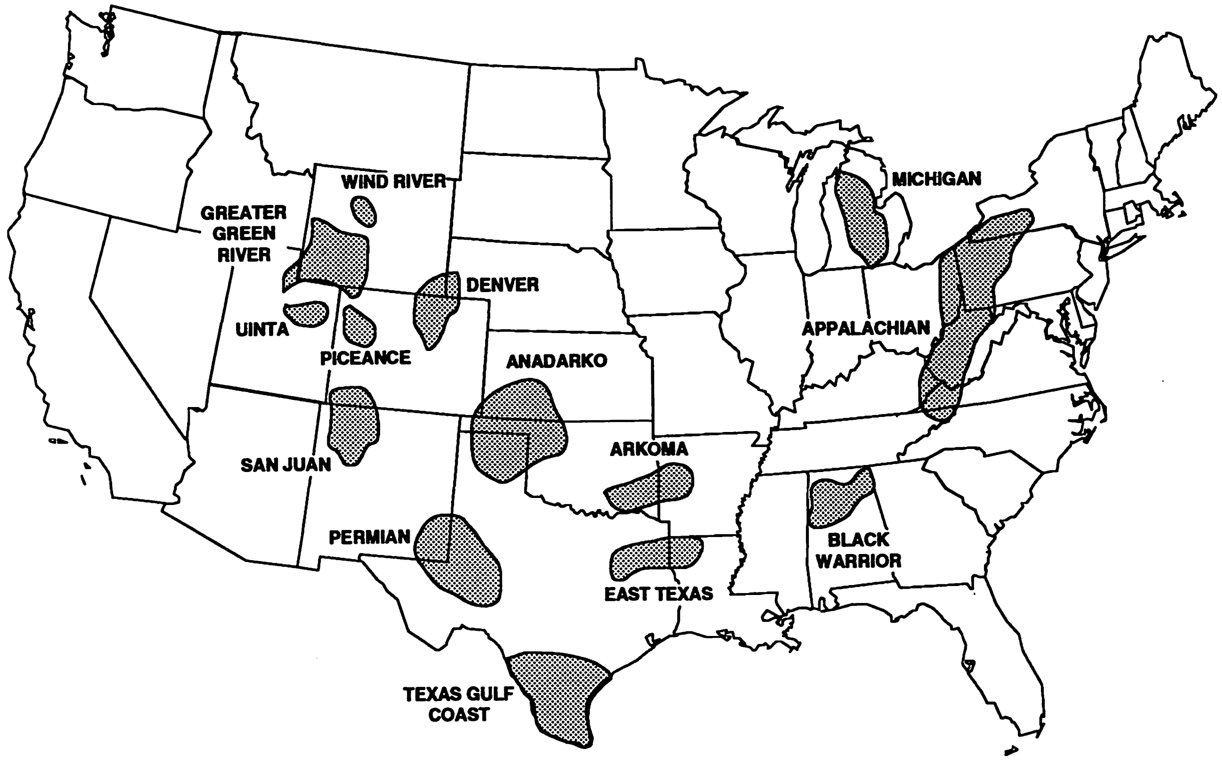

Figure 3-1. Location of Principal Nonconventional Gas Basins.

In Reference Case 2, the low energy growth scenario, with lower projected natural gas prices, modeled production of nonconventional natural gas is lower than in Case 1, but nevertheless grows substantially (to 3.0 TCF in 2000 and 3.9 TCF in 2010). In both cases, Section 29 tax credits are assumed to end for wells drilled after 1992.

In 1990, nonconventional gas production was about 12 percent of lower-48 gas production. Model results show nonconventional production increasing to about 22–27 percent of total lower-48 state production in 2010 in Reference Cases 1 and 2. This increased contribution of nonconventional gas is caused by the declining conventional gas resources coupled with the projected effects of advanced technology on the cost and recoverability of nonconventional gas, especially tight gas.

In-place resources of gas hydrates, geopressured brines, and deep gas are estimated to be as much as 12,000 TCF, but the cost of recovering gas from these speculative sources remains uncertain. No recoverable resources from these gas sources have been included in the NPC Reference Cases.

Reports prepared by the Nonconventional Gas Subgroup on tight gas, gas shales, coalbed methane, and speculative gas resources follow.

TIGHT GAS

Summary

The Natural Gas Policy Act of 1978 set the stage for the recognition of tight gas as a major potential increment to domestic gas supplies. By that time, the potential contribution of gas from tight sands was perceived to be large, but its magnitude was uncertain. One of the objectives of this study is to increase confidence in estimates of the size and productivity of the overall gas resource base, including those nonconventional sources, like tight gas, that are expected to make up an increasing share of future supply. The National Petroleum Council evaluated geological data, technology advances, costs, and other factors that might affect future tight gas development and production, and, based upon that evaluation, delineated the magnitude and character of the domestic tight gas resource base. This report summarizes the NPC's work on tight gas resources and potential future supplies from these resources. Working papers providing more detailed descriptions of the methodology and results are available from the NPC.

The tight gas resource base consists of proved reserves, reserve growth potential in existing fields, and new fields/reservoirs. The sum of reserve growth potential and new field potential represents the total quantity of undeveloped resource to be assessed and characterized. The NPC has not divided proved reserves into conventional and nonconventional categories.

The new field resource consists of resources in existing (producing) plays and resources in new or undeveloped plays. Because gas quantities in existing plays (or play areas) are better understood and are evaluated separately in the model (they are included in the historical "find rate" equations), this section reports separate estimates for gas in existing and new plays. For simplicity, reserve growth has been included with new field resources in existing plays. Therefore, the two categories reported are: (1) reserve growth and new fields in existing plays, and (2) new fields in new plays. The "new fields in new plays" category is modeled in a specific area of the hydrocarbon model called the Enhanced Recovery Module, or ERM.

Improved estimates of the resource base and its recovery potential were based on an extensive and confidential survey of current operators and detailed statistical analysis of historical production data. The NPC adopted the Federal Energy Regulatory Commission

TABLE 3-1

RECOVERABLE NONCONVENTIONAL RESOURCES
(Trillion Cubic Feet)

	Current Technology	Advanced Technology
Category of Gas		
Tight Gas	232	349
Devonian/Antrim Shale	37	57
Coalbed Methane	62	98
Total Nonconventional	**332**	**504**
Total Gas Resources, including Proved Reserves	**1,065**	**1,295**

TABLE 3-2

NONCONVENTIONAL GAS PRODUCTION
REFERENCE CASES 1 AND 2*
(Trillion Cubic Feet per Year)

	1990	2000	2010
Category of Gas			
Tight Gas	1.7	2.0 (1.6)	3.7 (2.6)
Devonian/Antrim Shale	0.2	0.5 (0.4)	0.5 (0.4)
Coalbed Methane	0.2	1.1 (1.0)	1.3 (0.9)
Total	**2.1**	**3.6 (3.0)**	**5.5 (3.9)**

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*Reference Case 2 shown in parentheses.

TABLE 3-3

TECHNICALLY RECOVERABLE TIGHT GAS RESOURCES (EXCLUDING PROVED RESERVES)

(Trillion Cubic Feet per Year)

	Current Technology	Advanced Technology*	"Second Generation" Advanced Technology†
Tight Gas			
Existing Plays‡	84	114	135
New Plays§	148	235	302
Total Resources	**232**	**349**	**437**

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* Used as NPC formal estimate of recoverable gas resources.

† Used in sensitivity runs to year 2030.

‡ Reserve growth and new fields in existing plays.

§ New plays are modeled in the Hydrocarbon Supply Model "Enhanced Recovery Module."

(FERC) legal definition of a tight formation—average in situ permeability of 0.1 millidarcy or less. For existing plays, the FERC tight formation designations were used to allocate resource between conventional and tight gas. For new plays, the NPC used the survey and the FERC designations to select 47 units of analysis. These analytic units generally represented a formation-depth interval combination within a basin recognized as having significant tight gas potential.

Tight gas has a significant potential to contribute an increasing share of the nation's gas supply. With current technology, about 84 TCF of technically recoverable tight gas resources are estimated in existing plays, and 148 TCF in new plays, for a total of 232 TCF (Table 3-3). The Foreland region (Rocky Mountains) contains the majority (53 percent) of this potential, followed by Arkla/East Texas (12 percent), Mid-continent (9 percent), Texas Gulf Coast and Permian Basins (each 8 percent), Appalachian (6 percent), and others (4 percent).

Using current technology and attribution of historical statistical averages, ultimate recoveries for the new plays would range from 80 million cubic feet (MMCF) per well to 2.5 billion cubic feet (BCF) per well, with a mean recovery of 550 MMCF per well. Technology improvements, however, are expected to increase recovery per well and decrease the cost of gas produced. Tight gas technology improvements are assumed to be introduced in increasing proportion through 2010, by which time all new tight gas wells will make use of advanced technology. For the recoverable resource of 148 TCF for new plays, improved technology could increase potential recovery per well between 40 percent and 70 percent, and total recoverable resources by about 60 percent, to 235 TCF. Recoverable resource in existing plays is forecast to increase about 36 percent over that period. Second generation technology improvements are added after 2010 in sensitivity runs simulating drilling, reserve additions and production through the year 2030.

Despite this large potential, the high front end costs incurred for stimulation make tight gas wells particularly sensitive to wellhead prices and technology advances. At $3.00 per thousand cubic feet (MCF) in 1990 dollars, well above current prices, potential recoverable resources with current technology for the new plays are 30 TCF, a relatively small proportion of the total technically recoverable tight gas. This increases to about 100 TCF at $3.00 per MCF with the evolution of technology (the advanced technology case).

Production of tight gas increases in both absolute and relative terms through 2010. From an estimated 1990 annual lower-48-state production of 1.7 TCF, annual production more than doubles to 3.7 TCF in 2010 in Reference Case 1, the moderate energy growth scenario.

The share of total domestic gas production made up by tight gas is estimated to increase from a current 10 to 18 percent in 2010. This increase occurs despite an estimated 18 percent increase in domestic production, to 20.5 TCF in 2010 from 17.3 TCF in 1990. Table 3-4 indicates the changing character of domestic gas production over 1990-2010 in Case 1.

Uncertainties remain as to the specific characterization of the resource base, costs of development, recovery efficiency, the manner in which reserves are added, and the flow of investment into tight versus other gas resources. The NPC conducted sensitivity analyses to determine the relative importance of these uncertainties on the level and timing of tight gas reserve additions and production. Several factors were identified as having the potential to affect estimated reserve additions and production, including drilling prospect selectability, rate of advancement of technology, constraints on drilling activity, and wellhead price. Table 3-5 shows the estimated impact on production of some of these assumptions.

Tight gas is expected to increase in importance over time (estimated to make up about one half of domestic gas supplies by 2030). The analysis was extended to 2030 for several price sensitivity cases. For the various price tracks, estimated tight gas production averaged 9 percent of total production in 2000 and 13 percent in 2010. After 2010, when the conventional resource base was being significantly depleted, tight gas production increased two- to three-fold, depending on price assumptions, and averaged 38 percent of total production in 2030 (Table 3-6).

The prices used in the $3.50 and $4.50 per million BTU price cases are considerably lower than Case 1 prices through 2010. The runs to the year 2030 differ somewhat from Reference Cases 1 and 2 in resource and other assumptions.

Although the potential resource base is quite large, the NPC has evaluated in detail only that portion for which sufficient data exist to adequately characterize potential resources. For example, the U.S. Geological Survey (USGS) has estimated that the overpressured tight formations in the Greater Green River Basin alone contain over 5,000 TCF tight gas in place. The economic development of most of this resource base is speculative at this time and is expected to require significant technology or cost improvements beyond those considered in this study. Therefore, only those portions of these high potential formations that are currently under development or are expected to be significantly developed during the study period (1990 to 2030) were included in the NPC's assessment.

A major constraint to more extensive exploitation is lack of a comprehensive geological and engineering characterization of the full

TABLE 3-4*

ESTIMATED LOWER-48 STATES TIGHT GAS PRODUCTION
REFERENCE CASE 1
(Trillion Cubic Feet per Year)

	1990	1995	2000	2005	2010
Tight Gas					
Existing Plays	1.7	1.8	1.7	1.9	1.9
New Plays	0.0	0.1	0.2	0.7	1.8
Subtotal Tight Gas	**1.7**	**1.8**	**2.0**	**2.6**	**3.7**
Other Nonconventional Gas	0.4	1.1	1.6	1.7	1.9
Conventional	12.5	12.7	12.7	13.6	12.9
Associated/Dissolved	2.7	2.2	2.0	2.1	2.0
Lower-48 States Supply	**17.3**	**17.8**	**18.3**	**20.0**	**20.5**

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*Columns may not sum to totals shown because of rounding.

TABLE 3-5

ESTIMATED U.S. TIGHT GAS PRODUCTION — SENSITIVITY ANALYSES*
(Trillion Cubic Feet per Year)

	1990	1995	2000	2005	2010
Case 1 †	1.7	1.8	2.0	2.6	3.7
Selectability ‡	1.7	1.7	1.9	2.4	3.2
Technology §	1.7	1.8	2.0	2.4	3.0
Development ¶	1.7	1.8	2.1	3.2	5.1
Price #	1.7	1.7	1.6	2.0	2.6

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* Total of tight gas in existing and new plays. All sensitivities except price were run against a particular base case, and the resulting differentials were applied to Reference Case 1.

† NPC Reference Case 1, moderate energy growth scenario.

‡ No resource selectability (reference Hydrocarbon Model Run SSS3-6).

§ No advanced technology available (reference SSS4-7).

¶ Relaxation of development constraints (reference SSS4-6).

# NPC Reference Case 2, low energy growth scenario. Also includes changes in macroeconomic assumptions.

TABLE 3-6

ESTIMATED LOWER-48 GAS PRODUCTION THROUGH YEAR 2030 UNDER ALTERNATIVE PRICE SCENARIOS
(Trillion Cubic Feet per Year)

Price*		2000	2010	2020	2030
$1.50	Tight	1.2	0.7	0.6	1.1
	Total	13.5	8.7	6.1	4.6
$2.50	Tight	1.4	2.2	4.7	4.6
	Total	16.9	16.0	15.2	11.6
$3.50	Tight	1.5	2.7	5.7	6.2
	Total	17.5	19.2	18.4	15.2
$4.50	Tight	1.5	2.8	5.8	8.9
	Total	17.5	19.8	20.1	19.1
Avg. % Tight		9	13	25	38

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*Gulf Coast maximum wellhead price for gas in 1990$ per million BTU.

tight gas resource base. Although focused on conventional gas resources, current efforts by the Department of Energy (DOE) and the Gas Research Institute (GRI) to characterize the domestic natural gas resource base in a series of gas atlases will supply some of these tight gas data. However, a great deal of additional data specific to tight gas formations needs to be collected and evaluated to adequately characterize the entire tight gas resource on a consistent basis that would allow development of a more focused and effective research and development (R&D) strategy by industry and government. Given the vast expected potential of the tight gas resource, improved characterization could help industry to reduce finding and development costs and bring greater volumes of tight gas into production.

Introduction and Background

Prior Estimates of Tight Gas Potential

Several detailed studies of tight gas have been conducted over the past 20 years. Six of them are compared in Table 3-7. The purposes and analytical approaches were different for each study. Wide differences in results have led many to question the validity of any of these estimates. Some studies covered a large number of basins while others covered only a few, and some estimated only resources in place rather than in place and recoverable resources.

- ***Federal Power Commission (1973).*** The FPC conducted the first major assessment of tight gas resources, estimating 600 TCF of gas in place in three western basins, the Green River, Piceance, and Uinta.
- ***Federal Energy Regulatory Commission (1978).*** Accepted the FPC estimates for the three western basins, but added the Northern Great Plains (130 TCF) and the San Juan Basin (63 TCF), for a total tight gas in place of 793 TCF.
- ***Lewin and Associates (1978).*** Conducted the first comprehensive tight gas appraisal at the play level, covering 13 basins. Lewin estimated 423 TCF of tight gas in place in the most prospective formations. The methodology was to evaluate the productivity and economics of a series of typical wells used to represent portions of the tight gas resource. Lewin's assessment excluded formations below 12,700 feet, although tight formations (e.g., South Texas Vicksburg, Washakie Frontier) occur to 20,000 feet.
- ***National Petroleum Council (1980).*** Extended the Lewin study in the most comprehensive and industry-standard tight gas appraisal to date. Industry geologists and reservoir engineers were assigned to appraisal teams to evaluate 113 known and expected tight gas producing areas and basins under a variety of technologic and economic assumptions, essentially using the Lewin analytic method. The NPC estimated 444 TCF gas in place existed in 10 basins, with another 480 TCF in

TABLE 3-7

COMPARISON OF PRIOR MAJOR TIGHT GAS ASSESSMENTS
(Trillion Cubic Feet of Tight Gas in Place)

Appraised Basins	FPC (1973)	FERC (1978)	Lewin (1978)	NPC (1980)	USGS (1989)	ICF (1990)
Northern Great Plains/ Williston		130	74	148		
Greater Green River	240	240	91	136	5,063	
Uinta	210	210	50	20		
Piceance	150	150	36	49	423	287
Wind River			3	34		
Big Hom			24			
Douglas Creek			3			
Denver			19	13		
San Juan		63	15	3		17
Ozona				1		
Sonora			24	4		
Edwards Lime				14		
Cotton Valley Sweet			67	22		31
Cotton Valley Sour			14			

potentially productive basins without sufficient development to appraise in detail. The NPC excluded tight formations deeper than 15,000 feet. The NPC included in their assessment 40 TCF of resource with permeabilities above 0.1 millidarcy. For regulatory purposes, tight sands are defined as having permeabilities less than 0.1 millidarcy.

Subsequent to the 1980 NPC study, *Unconventional Gas Sources*, several analyses of individual basins were conducted. The purpose of these studies was to delineate the full extent of the resource base (because the NPC had analyzed only the most likely production targets) and estimate potential recovery based on contemporary technical and economic specifications. The principal analysts for these basin studies were the USGS and ICF Resources. The USGS estimated potential recovery from the Green River and Piceance Basins and is completing work on the Uinta Basin. ICF Resources completed studies of the East Texas, San Juan, Piceance, Sand Wash, and Great Divide Basins.

- ***U.S. Geological Survey (1987-90).*** The USGS conducted two play analyses of tight sands in the Green River and Piceance Basins to estimate a most likely tight gas in place of 5,063 TCF and 423 TCF, respectively. These estimates were based on detailed geological appraisals of overpressured formations only, specifically gas-bearing tight zones greater than 10 feet thick. The USGS estimated much larger volumes in place than previous estimates (the 1980 NPC study estimated 136 TCF tight gas in place for the Green River and 49 TCF for the Piceance). Estimates of technical recovery were made using recovery factors rather than reservoir modeling. The USGS estimated that 73 TCF and 13 TCF might be recoverable from the Green River and Piceance Basins, respectively, with current technology and wellhead prices up to $5.00 per MCF in 1987 dollars. The USGS estimated that, under advanced technology and no price constraints, up to 433 TCF and 68 TCF of tight gas might be recovered in the Green River and Piceance Basins, respectively. These large in place and recoverable estimates do not address what specific technologies will be needed to recover this gas.

  It is important to remember that the 1980 NPC estimates were made for the near-term, single most productive formations that industry would likely target, while the USGS estimated the total gas in place for entire vertical sections, some of which are several thousand feet thick. Thus, each appraisal must be viewed on its own terms. Given the improvement in geological knowledge and technology over the past decade, the 1980 NPC estimates are too conservative. Conversely, since they are based on play analyses, the USGS estimates cannot be translated directly into typical well recoveries and developed into price supply curves for input into supply models. Both, however, provide an important context for the current NPC tight gas appraisals.

- ***ICF Resources (1990-91).*** All prior tight gas studies were based on a distribution of typical wells or a play analysis of expected reservoir properties, which is the appropriate approach for a relatively unexplored resource. For two relatively mature basins (East Texas and San Juan), ICF Resources conducted more detailed basin appraisals to derive both remaining in place and recoverable tight gas at a township level basis. For a third basin (Piceance), which had a wide range of resource estimates, ICF Resources estimated tight gas in place for 21 plays in the basin for six tight Cretaceous formations. Results of these appraisals were East Texas (31 TCF in place; 6.2 TCF recoverable resources at $2.00 per MCF and current technology), San Juan (17 TCF in place and 2.3 TCF recoverable resources) and Piceance (287 TCF in place and 6 TCF recoverable resources).

- ***Enron (1991).*** Enron Corporation conducted the first major industrial outlook to assess not only conventional but unconventional gas resources on a disaggregated basis. The study concluded that 201 TCF of recoverable tight gas exists in the lower-48 states, one-fifth of the total remaining identified recoverable natural gas resource base.

Most estimates of tight gas potential that have been prepared by the Gas Research Institute, the American Gas Association, and the Department of Energy are derived from the geological appraisals in the 1980 NPC study.

The current NPC resource characterization is also not directly comparable to these prior studies. Past analyses were based on extensive geological appraisals and reservoir modeling to determine potential well recoveries. The current NPC study methodology was based on expected average well recoveries for specific formations and areas, but did not estimate the corresponding gas in place because it is relatively unimportant. Therefore, direct comparisons of the tight gas resource base cannot be made and comparisons of recoverable resources are subject to misinterpretation due to differences in analytic assumptions.

Study Objectives

The Secretary of Energy commissioned the NPC to conduct this study to determine the opportunities to expand production, distribution, and use of natural gas. Since the 1980 NPC study on nonconventional gas resources, the large potential of tight gas has been seen as a major increment to domestic supplies. The 1980 NPC report defined the known and expected resource base and the technological and economic parameters that most influence production potential. This 1992 NPC study has provided an opportunity to update the prior analysis and redefine critical factors likely to affect tight gas development. The NPC's focus has been to estimate potential reserves from only that portion of the resource base that could be characterized with confidence, excluding extrapolated or speculative tight gas resources.

General Description of the Tight Gas Resource

Tight gas is found in almost every sedimentary basin in the United States, but tight formations vary widely in their origin. In almost all wells, gas flow rates are noncommercial without artificial stimulation. Much of the recent research has been directed toward defining those geological and technological parameters that control tight gas recovery, and toward increasing flow rates and volume of reservoir that can be effectively produced by a single well.

The USGS and others have categorized tight gas reservoirs by reservoir genesis and geological characteristics. Many of the Rocky Mountain tight formations, where a majority of potential reserves is thought to exist, are characterized by extremely low porosity and matrix permeability and limited reservoir continuity. Tight gas reservoirs are also characterized by small grain size, intergranular cementation, restricted pore throats, and complex reservoir architecture. Each of these features requires sophisticated reservoir evaluation and extraction techniques to profitably produce gas.

Historical Trends and Future Expectations for Tight Gas Production

Until the introduction of massive hydraulic fracturing in the late 1940s, tight gas production was limited to a few favorable settings. A growing demand for gas in California and the relatively thick, uniform blanket sands of the San Juan Basin created the first major tight gas play in the 1950s.

By the early 1970s, an estimated 450 BCF per year of tight gas was being produced in the Southwest and Rocky Mountains. The producing wells were generally associated with conventional gas reservoirs instead of entirely tight gas plays. A combination of improving technology and federal price incentives pushed tight gas production up to 1.2 TCF by 1981. Development was centered in East Texas, Gulf Coast, Permian, San Juan Basin, Piceance, Denver, and Green River Basins. Amoco Corporation's subsurface studies and fracturing research turned the Denver-Julesberg Wattenberg J Sand into the nation's first wholly tight gas play in the 1970s.

With the decline of gas prices and gas demand during the 1980s, the development of tight gas slowed considerably. Many of the lower productivity tight gas wells were shut in and exploration for tight gas diminished significantly. Companies with aggressive tight gas development programs concentrated on areas in which they had adequately characterized the geology and had a technological advantage over competitors.

With reinstatement of Section 29 federal production tax credits for tight gas in 1990, tight gas development once again accelerated. Major drilling efforts are underway in the East Texas, Gulf Coast, Permian, Denver, and Green River Basins. Estimates of drilling in 1991 for tight gas range up to 2,500 wells, with tight gas well determination filings averaging over 300 per month by early 1992.

Current Issues and Uncertainties in Estimating Tight Gas Potential

Estimates of future drilling and production are based on assumptions about improvements in cost and technical performance as well as the quality of the remaining resource base. The gas industry and other energy industries are implementing cost control measures because of continuing low prices, and will seek resources that can be recovered at low cost. For tight gas, characterized in the past as "high cost," producers will have to concentrate on formations that can be developed with minimal risk of dry holes using the most cost-effective technologies.

Additional advances in formation evaluation, stimulation design and modeling, reservoir diagnostics, and other new technologies are expected to help unlock much of the tight gas resource base that is uneconomic at current prices. In many tight gas reservoirs, the dominant flow occurs in natural fractures created by tectonic stresses. Due to the nature of these stresses, induced hydraulic fractures are limited in their ability to intersect these natural fractures and efficiently drain the reservoir. The ability to connect these high permeability channels to the wellbore through the use of inclined wellbores, however, holds great promise to increase flow rates for many wells, particularly in western basins. Initial tests of this technology are promising, but more research is needed to confirm its overall potential.

Methodology of Current Study

There are several methodologies used to estimate gas resource potential, the selection of which depends primarily on the availability of valid reservoir data. As a play matures, the confidence in reserve estimation increases and more accurate methods can be used. Tight gas reservoirs and formations have traditionally been used to estimate potential. Given the increased development of tight gas over the last few years and the consequent increase in reservoir studies and data collected, an additional calibration method was sought for this study.

Resource Description

In this 1992 NPC study, the tight gas resource base has been defined for both existing and new plays. The existing plays were estimated as a fraction of the total resource in the field size distributions of the Hydrocarbon Model. Those distributions are based on established historical production and drilling data and were accepted as described in the Conventional Gas section of this report.

The new tight gas plays have been estimated independently as to potential recovery and individual well economics. The Hydrocarbon Model ERM was used for this purpose, by assigning a typical well in a formation/depth interval to each cell in the ERM. Each cell was characterized by a mean recovery per well, total numbers of potential wells, capital and operating costs, and dry hole rates. For this assessment, 47 ERM cells were used to characterize the tight gas resource base not represented in field size distributions of the Hydrocarbon Model.

The NPC based its estimates of ERM resource base, well recoveries, and costs on a confidential survey of operators in known tight gas formations. Respondents included 5 integrated companies, 5 independents, and 2 consultants. The survey included at least one operator from 9 of the most significant tight gas producing basins and formations (Appalachian, East Texas/North Louisiana, Texas Gulf Coast, West Texas, San Juan, Denver, Piceance, Uinta, and Green River). Survey data were evaluated and transformed into consistent distributions of well recoveries and costs for use in Hydrocarbon Model runs. Survey respondents provided detailed estimates of formations currently under development and their best judgment on remaining resources in their respective areas of expertise.

In areas not covered by the survey, and as a means to validate survey results, historical production data and 1980 NPC study results were used to estimate resource base and per well recoveries. Dwight's Energy well production data were used for producing wells in known tight formations to derive a distribution of expected ultimate well recoveries. These were used to calibrate survey results, or adapted as a basis for estimating ultimate recoveries of tight gas wells where no survey data were available. Since some of these formations contained non-tight wells, well distributions were adjusted to exclude these non-tight wells. In predominantly tight formations, the top 10 percent highest recovery wells were removed from the distributions to back-out non-tight wells. In partially tight formations, the top 20 percent of wells were excluded.

Technology Assumptions

The NPC considered several methods of representing improvements in technology, but decided that it could not assume specific technological improvements for individual ERM cells. Therefore, an average rate of improvement in recovery efficiency was specified for each cell, to be implemented at a constant rate over the 1990-2010 period.

In nonconventional reservoirs, however, the current low recoveries are usually dominated by the inability of the well to contact all the gas in the drilling pattern. Technologies designed to increase reservoir contact, therefore, are most effective in the lowest recovery wells. Higher productivity wells, already contacting a greater percentage of total gas, would increase recovery by a smaller percentage than lower recovery wells. The study group thus specified that wells recovering less than 0.5 BCF could increase recovery by 70 percent, wells recovering between 0.5 and 1.5 BCF could increase recovery by 60 percent, wells between 1.5 and 2.5 BCF could increase by 50 percent, and wells recovering over 2.5 BCF could increase 40 percent. The effect of this method is to potentially increase the recovery of the average well in the ERM by about 60 percent using advanced technology.

Technology could increase ultimate well recoveries in several ways. Better fracturing is the most obvious; as discussed below, additional costs have been added to wells in the advanced technology case to represent more extensive fracturing methods or fracturing of multiple zones. Horizontal or slant drilling may also improve recovery in some situations. Slim hole drilling combined with closer well spacing may be cost effective in some areas.

Economics

Well costs for tight gas sands, with the exception of stimulation costs, were consistent with those used in the Hydrocarbon Supply Model for all other gas sources. Stimulation costs were based on the survey of operators. There was considerable debate as to whether advances in technology would increase the size and cost of fracture treatments or whether the size would remain the same and costs would decrease. The approach selected for the study assumed that the increased use of multistage fracturing would be used most frequently and would increase the stimulation costs per well.

The NPC examined well cost and stimulation cost data based upon current technology for input to the ERM. Drilling and completion costs of tight gas wells, highly dependent on depth and formation characteristics, ranged from $120,000 for shallow Denver Basin wells to $3.5 million for deep Green River Basin Mesaverde wells. Stimulation costs also varied considerably, ranging from $100,000 to $450,000. Geological and geophysical costs were estimated on a per foot basis and dry holes were estimated independently for each region.

Reserve Additions

Reserves are added from the Low Permeability resource and ERM cells using the same method as for other gas resources in the Hydrocarbon Model. Based on discounted cash flow analysis of typical wells within a cell, reserves are added based on rate of return relative to other cells or resource units. Cash flow and inertial constraints on investment for tight gas are applied, as they are for other categories of gas in the model.

An additional feature of the Hydrocarbon Supply Model was used to reflect the distribution of well recoveries represented by the mean recovery in each ERM cell. There is an inherent "selectability" used by operators in developing gas resources, whereby drilling is non-random based on knowledge of the subsurface characteristics and production histories. In newly drilled areas, where data are limited, development is more random and the best prospects are less selectable. Conversely, in a more mature area, the extensive knowledge base provides high selectability, allowing the operator to target the better of the remaining prospects first. Each ERM cell was assigned a selectability value based on evaluation of geological characteristics and historical production patterns ranging from highly selectable to completely random.

Production Profiles

Once reserves are added, production from typical wells is modeled as a decline curve of the percentage of ultimate recovery produced in a given year. These decline curves were derived from survey data and analysis of Dwight's production data for typical wells in nonsurveyed formations.

Description of the Resource Base

Regional Distribution of Tight Gas Potential

With base technology, a total of 84 TCF of potential tight gas reserve additions is estimated for existing plays, and 148 TCF for new plays (the ERM cells), for a total potential tight gas resource recovery of about 232 TCF. The Foreland region (Rocky Mountains) contains the majority (53 percent) of this potential, followed by Arkla/East Texas (12 percent), Midcontinent (9 percent), Texas Gulf Coast and Permian Basins (each 8 percent), Appalachian (6 percent), and others (4 percent), as shown in Table 3-8.

Technology improvements are expected to increase recovery per well and decrease costs per MCF produced. The application of advanced technology to tight gas is consistent with the method explained in Chapter Five, Technology. Advanced tight gas technology is assumed to steadily become more widely applied over the period through 2010, after which all tight gas wells use advanced technology. For the same resource base of 148 TCF for undeveloped plays, improved technology could increase potential reserve additions by about 60 percent, to 235 TCF.

Despite this seemingly large potential, the high front-end costs incurred for stimulation make tight gas wells particularly sensitive to wellhead gas prices. At $3.00 per MCF, well above current prices, potential resources with current technology for the ERM cells are estimated to be only 30 TCF, but increase to 103 TCF with advanced technology.

Detailed Resource Characterization

Individual formations were further characterized to reflect contemporary understanding of the resource base in new tight formations. Table 3-9 provides the details of this characterization for the ERM cells. Total

TABLE 3-8

ESTIMATED U.S. TIGHT GAS RESOURCE BASE
TECHNICALLY RECOVERABLE, CURRENT TECHNOLOGY*
(Trillion Cubic Feet)

Region	Old Plays		New Plays	Total
	New Fields	Old Fields		
A (Appalachian)	3.4	0.0	10.5	13.9
D (Arkla-Tex)	4.2	4.2	19.0	27.4
G (S. Texas Onshore)	7.1	5.5	5.8	18.4
WL (Williston)	0.4	0.3	0.0	0.7
FR (Foreland)	26.4	7.3	89.9	123.6
SJB (San Juan Basin)	1.3	6.5	0.0	7.8
JN (Midcontinent)	8.4	2.7	10.8	21.9
JS (Permian)	2.3	4.0	12.4	18.7
Total	**53.6**	**30.4**	**148.4**	**232.4**

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* Some columns and rows do not sum to totals because of rounding.

TABLE 3-9

DISTRIBUTION OF TIGHT GAS RESOURCES IN NEW PLAYS

		Current Technology			Advanced Technology		
Basin and Formation	**Depth (Feet)**	**Recovery (BCF)**	**Mean Re-covery/Well (MMCF)**	**No. Succ. Wells**	**Recovery (BCF)**	**Mean Re-covery/Well (MMCF)**	**No. Succ. Wells**
Region A – Appalachia							
Clinton Deep (OH)	6,000	1,115	150	7,433	1,896	255	7,433
Clinton Shallow (OH)	4,500	2,342	80	29,275	3,981	136	29,275
Berea (OH)	1,550	780	80	9,750	1,326	136	9,750
Medina (PA)	5,000	1,115	153	7,288	1,895	260	7,288
Bradford (PA)	3,500	2,119	175	12,109	3,602	298	12,109
Berea – Gordon (WV)	3,600	446	100	4,460	758	170	4,460
Benson (WV)	4,500	1,673	200	8,365	2,844	340	8,365
Medina (NY)	2,500	781	100	7,810	1,328	170	7,810
Berea (KY)	1,500	22	180	122	37	306	122
Comiferous (KY)	2,500	112	179	626	190	304	626
Oriskany (PA)	5,000	691	150	4,607	1,175	255	4,607
Total/Average		**11,196**	**122**	**91,844**	**19,033**	**207**	**91,844**
Region D – East Tx, Arkla							
E. Texas – James Lime	8,100	629	545	1,154	1,006	872	1,154
E. Texas – Travis Peak	8,400	793	1,250	634	1,269	2,000	634
E. Texas – Cotton Valley	10,200	12,604	2,233	5,644	18,906	3,350	5,644
Arkla – James Lime	8,000	109	349	312	185	593	312
Arkla – Travis Peak	7,800	468	1,250	374	749	2,000	374
Arkla – Cotton Valley	9,200	1,400	735	1,905	2,240	1,176	1,905
Arkla – Smackover	11,100	2,979	574	5,190	4,776	918	5,190
Total/Average		**18,982**	**1,248**	**15,214**	**29,122**	**1,914**	**15,214**

TABLE 3-9 (Continued)

Basin and Formation	Depth (Feet)	Current Technology Recovery (BCF)	Current Technology Mean Recovery/Well (MMCF)	Current Technology No. Succ. Wells	Advanced Technology Recovery (BCF)	Advanced Technology Mean Recovery/Well (MMCF)	Advanced Technology No. Succ. Wells
Region G – Texas Gulf Coast							
Vicksburg	10,500	240	1,482	162	384	2,371	162
Cook Mountain	10,400	160	229	699	272	389	699
Lobo	8,900	2,556	1,390	1,839	4,090	2,224	1,839
Olmos	4,800	1,677	201	8,343	2,851	342	8,343
Edwards Lime	11,700	1,118	1,425	785	1,789	2,280	785
Total/Average		**5,751**	**486**	**11,827**	**9,385**	**794**	**11,827**
Region FR – Rockies							
Green River – Ft. Union	6,300	2,990	907	3,297	4,784	1,451	3,297
Green River – Lance	5,600	3,707	822	4,510	5,931	1,315	4,510
Green River – MV/Lewis – Intermed.	9,500	30,391	1,500	20,261	45,587	2,250	20,261
Green River – MV/Lewis -Deep	12,000	12,157	1,000	12,157	19,451	1,600	12,157
Green River – MV/Lewis -VDeep	15,000	4,052	500	8,104	6,888	850	8,104
Green River – Frontier	8,800	2,917	1,390	2,099	4,667	2,224	2,099
Piceance – Wasatch	2,600	327	510	641	523	816	641
Piceance – MV Intermed.	6,000	8,718	500	17,435	13,948	800	17,435
Piceance – MV Deep	4,359	8,718	500	17,435	13,948	800	17,435
Piceance – Mancos/Dakota	6,000	847	303	2,795	1,440	515	2,795
Wind River – Fr. Union/Lance	7,200	6,581	905	7,272	10,530	1,448	7,272
Wind River – Mesaverde, etc.	10,300	1,804	2,516	717	2,526	3,522	717
Uinta – Wasatch	6,600	4,194	1,008	4,161	6,710	1,613	4,161
Denver – Sussex/Codell	7,000	190	200	950	323	340	950
Denver – Niobrara	1,500	410	100	4,100	697	170	4,100
Denver – D and J	8,000	1,928	497	3,879	3,278	845	3,879
Total/Average		**89,930**	**819**	**109,812**	**141,231**	**1,286**	**109,812**

TABLE 3-9 (Continued)

		Current Technology			Advanced Technology		
Basin and Formation	Depth (Feet)	Recovery (BCF)	Mean Recovery/Well (MMCF)	No. Succ. Wells	Recovery (BCF)	Mean Recovery/Well (MMCF)	No. Succ. Wells
Region JN – Midcontinent							
Anadarko – Cleveland	7,400	3,792	505	7,509	6,067	808	7,509
Anadarko – Cherokee/Red Fork	11,000	2,800	510	5,490	4,480	816	5,490
Anadarko – Granite Wash/Atoka.	11,400	3,433	774	4,435	5,493	1,238	4,435
Arkoma – Atoka	9,800	817	456	1,792	1,389	775	1,792
Total/Average		**10,842**	**564**	**19,226**	**17,429**	**907**	**19,226**
Region JS – Permian							
Abo	3,800	1,823	391	4,662	3,099	665	4,662
Canyon SS	6,100	7,900	560	14,107	12,640	896	14,107
Strawn, Atoka, etc.	12,000	985	418	2,356	1,675	711	2,356
Morrow and Mississippian	13,000	1,682	922	1,824	2,691	1,475	1,824
Total/Average		**12,390**	**540**	**22,950**	**20,105**	**876**	**22,950**
Lower-48 Total/Average		**149,091**	**550**	**270,874**	**236,305**	**872**	**270,874**
Lower-48 Total/Average Adjusted to 1/1/91 Basis		**148,440**			**235,204**		

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* The data in this table are on a January 1, 1986, basis which is the starting date for each model run. The data in Table 3-8 are on a January 1, 1991 basis. Only the Appalachian region shows a significant difference between the 1986 and the 1991 basis.

recovery, mean recovery per well, and estimated number of wells are provided for each of the 47 ERM cells for current and advanced technologies.

Using current technology, per well ultimate recoveries for the undeveloped plays range from 80 MMCF to 2.5 BCF, with a mean recovery of 550 MMCF. Developing the total resource in new plays would require over 270,000 wells.

Reserve Additions and Production Under the Reference Cases

Reserve Additions

Computer runs using the Hydrocarbon Model show that tight gas makes up an increasing share of total U.S. gas reserve additions in the future, as shown in Tables 3-10 and 3-11. The NPC modeled tight gas reserve additions in the respective regions for two reference cases: Reference Case 1, the moderate energy

TABLE 3-10

ESTIMATED U.S. TIGHT GAS RESERVE ADDITIONS — REFERENCE CASE 1
(Trillion Cubic Feet per Year)

	1990	1995	2000	2005	2010
Gulf Coast Price (1990$/MMBTU)	1.51	1.98	2.88	2.76	3.47
Tight Gas					
Existing Plays	1.7	1.1	1.7	1.9	2.2
New Plays	0.1	0.2	0.7	1.9	5.1
Total Tight Gas*	**1.8**	**1.2**	**2.5**	**3.9**	**7.3**
Total Gas	**18.5**	**15.1**	**18.7**	**22.3**	**22.5**
Percentage Tight	10	8	13	18	32

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* Columns may not sum to totals shown because of rounding.

TABLE 3-11

ESTIMATED U.S. TIGHT GAS RESERVE ADDITIONS — REFERENCE CASE 2
(Trillion Cubic Feet per Year)

	1990	1995	2000	2005	2010
Gulf Coast Price (1990$/MMBTU)	1.51	1.61	2.36	2.45	2.74
Tight Gas					
Existing Plays	1.7	0.7	1.4	1.4	2.0
New Plays	0.1	0.1	0.3	0.9	2.6
Total Tight Gas*	**1.8**	**0.8**	**1.7**	**2.3**	**4.6**
Total Gas	**18.5**	**11.8**	**15.5**	**17.9**	**18.3**
Percentage Tight	10	7	11	13	25

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* Columns may not sum to totals shown because of rounding.

growth scenario, and Reference Case 2, the low energy growth scenario, which incorporated more conservative macroeconomic assumptions and lower gas prices. Tight gas reserve additions are shown to grow at a compound annual rate of over 7 percent from 1990 through 2010 for Case 1, while total gas reserve additions are indicated to grow about 1 percent per year. While tight gas reserve additions were about 10 percent of total gas reserve additions in 1990, they are shown to increase to 32 percent by 2010.

Tight gas reserve additions are shown to increase at about 5 percent per year from 1990 through 2010 in Case 2, while total gas reserve additions are indicated to be about the same in 2010 as in 1990. Tight gas reserve additions are projected to reach 25 percent of total reserve additions in 2010 (Table 3-11).

Production

The Hydrocarbon Supply Model runs show that production from current and future tight gas reserves increases in Reference Case 1 at a compound annual rate of about 4 percent over the next 20 years. Most of this growth is from the portion of the resource in new plays (represented by the ERM). Total gas production is shown to increase at about 1 percent per year from 1990 through 2010. Tight gas is projected to increase from 10 percent of lower-48 production in 1990 to 18 percent in 2010.

In Reference Case 2, annual tight gas production is projected to increase at about 2 percent per year, while total gas production stays flat. The tight gas share of production increases to 15 percent in 2010 from 10 percent in 1990. Tables 3-12 and 3-13 show estimated production for the two tight gas resource components for the two scenarios.

Sensitivities

Although the estimated resource base and recoveries represent the knowledge and expert opinions of industry and consultants, these and other estimates are subject to uncertainty. Sensitivity analyses were conducted for selectability, technology, development constraints, and oil and gas prices, and are discussed below. The impact of each sensitivity on modeled production is shown in Table 3-5. Additional sensitivities on the overall size of the resource base, and factors generic to all resource types, are not discussed separately here.

Selectability

The ability of geological characterization and reservoir modeling to improve the selectability of development prospects can increase the economic attractiveness of a tight formation. By reducing the number of uneconomic wells drilled, an operator can increase the effective rate of return and begin development of a formation at a lower wellhead gas price than in the absence of selectability (i.e., random drilling).

The study group characterized each cell in the ERM by one of three levels of selectability, based on geological characteristics and trends in historical production data in the region. From the operator survey and an independent analysis of Dwight's production data, a raw distribution of well recoveries was assigned to each cell. Under perfect selectability, an operator would drill all the highest productivity class wells before proceeding to the next highest productivity class, until all wells in the formation were drilled. Under random drilling, the expected recovery from each well would be the mean recovery for the formation. The three selectability values were based on a weighted average of the raw selectability distribution and the random drilling distribution for each of the 47 cells. Lower selectability cells were characterized by greater weight being attributed to the random drilling distribution.

A sensitivity analysis was conducted to estimate the change in reserve additions and production of tight gas if wells were drilled with zero selectability or randomly. This sensitivity analysis was conducted only for the resource in the ERM. The results of the sensitivity analysis showed a significant impact on tight gas potential. Relative to Reference Case 1, tight gas production is estimated to be reduced by about 0.1 TCF in 2000 and by about 0.5 TCF in 2010 (a 14 percent reduction) by the absence of selectability.

Advanced Technology

NPC Reference Case 1 assumes that successful R&D and commercialization of tight gas technologies occur steadily through 2010. Should R&D funding decline or commercialization of

TABLE 3-12

ESTIMATED U.S. TIGHT GAS PRODUCTION — REFERENCE CASE 1
(Trillion Cubic Feet per Year)

	1990	**1995**	**2000**	**2005**	**2010**
Gulf Coast Price (1990$/MMBTU)	1.51	1.98	2.88	2.76	3.47
Tight Gas					
Existing Plays	1.7	1.8	1.7	1.9	1.9
New Plays	0.0	0.1	0.2	0.7	1.8
Total Tight Gas*	**1.7**	**1.8**	**2.0**	**2.6**	**3.7**
Total Gas	**17.3**	**17.8**	**18.3**	**20.0**	**20.5**
Percentage Tight	10	10	11	13	18

*** Columns may not sum to totals shown because of rounding.**

TABLE 3-13

ESTIMATED U.S. TIGHT GAS PRODUCTION — REFERENCE CASE 2
(Trillion Cubic Feet per Year)

	1990	**1995**	**2000**	**2005**	**2010**
Gulf Coast Price (1990$/MMBTU)	1.51	1.61	2.36	2.45	2.74
Tight Gas					
Existing Plays	1.7	1.6	1.5	1.7	1.7
New Plays	0.0	0.1	0.1	0.3	0.9
Total Tight Gas*	**1.7**	**1.7**	**1.6**	**2.0**	**2.6**
Total Gas	**17.3**	**17.1**	**16.0**	**17.4**	**17.4**
Percentage Tight	10	10	10	11	15

*** Columns may not sum to totals shown because of rounding.**

novel technologies fail to occur, tight gas production would be less than estimated. In this sensitivity, current technology is assumed to be used for all tight gas wells in the ERM. Although the effect is minimal through 2000, the decrease in potential production due to lack of advanced technology becomes more pronounced over time. By 2010, estimated annual production under a "no advanced technology" case is estimated at 3.0 TCF. This is about 20 percent lower than the 3.7 TCF estimated for Case 1 in 2010.

Development Constraints

The Hydrocarbon Model places a constraint on how quickly investment and drilling can shift between regions in response to changing profitability of drilling prospects. For the ERM, certain rules have been established to determine how quickly a cell can be developed:

- In the first year of development, reserve additions can total only 0.5 percent of the ultimate recovery of the cell.

- Investment in a cell cannot increase above the previous year by more than 20 percent.
- At most, 10 percent of the original resource in a cell can be developed as reserves in a given year.
- At most, 40 percent of the remaining resource in a cell can be developed as reserves in a given year.

Changing the investment constraint to 40 percent from 20 percent per year would increase tight gas production by 1.4 TCF in 2010. Tight gas production increases above that in Case 1 by 5 percent in 2000 and about 40 percent in 2010.

Wellhead Prices

The level of oil and gas prices does not change the conclusion that tight gas will make up an increasing share of total domestic gas production in the future, but does have a significant impact on the amount of gas produced, as previously discussed in comparing Reference Cases 1 and 2.

A sensitivity analysis to oil and gas prices was run, with relatively constant potential demand, to estimate rates of reserve additions and production from the various components of the gas resource base through 2030. Cases were run with maximum Gulf Coast gas prices of $1.50, $2.50, $3.50, and $4.50 per million BTU, with prices specified in 1990 dollars. Oil prices increased by 2030 to $26.00 per barrel in the lower two price cases and to $36.00 per barrel in the higher two price cases. Potential gas demand after 2010 was assumed to be flat in the three lower price cases but to increase at 0.5 percent annually in the $4.50 per million BTU case.

For this price sensitivity analysis, technology was assumed to continue to improve well recoveries and recoverable resources over the 2010-2030 period, but at a lower rate than in the 1990-2010 period. Technically recoverable resources are shown in Table 3-14.

Under any price scenario, tight gas increases its share of total gas production from 9 percent in 2000 to an average of 38 percent in 2030 (Table 3-15). Although, under the $1.50 case, total gas production decreases from 13.5 TCF in 2000 to 4.6 TCF in 2030, projected production of tight gas in 2030 is 1.1 TCF. This is indicative of the dominance of tight gas in the remaining recoverable natural gas resource base.

The prices in the 2030 cases are lower through 2010 than in Reference Case 1. In the $3.50 and $4.50 per million BTU price cases, the projected Gulf Cost wellhead price in 2010 is $3.11 per million BTU, while in Case 1 it is projected at $3.47 and in Case 2 at $2.74. The $3.50 per million BTU maximum price is reached by 2015 in the $3.50 case, and the $4.50 per million BTU maximum price is reached by 2020 in the $4.50 case.

Under the higher price cases, total gas production is estimated to be maintained at near current levels before eventually declining,

TABLE 3-14

TECHNICALLY RECOVERABLE TIGHT GAS RESOURCES
(Trillion Cubic Feet)

	Base Technology	1990-2010 Advanced Technology*	"Second Generation" Advanced Technology†
Tight Gas			
Existing Plays	84	114	135
New Plays	148	235	302
Total Resources	**232**	**349**	**437**

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* Used as NPC formal estimate of gas resources.

† Applicable to the 2010-2030 period.

TABLE 3-15

ESTIMATED LOWER-48 GAS PRODUCTION THROUGH YEAR 2030
UNDER ALTERNATIVE PRICE SCENARIOS
(Trillion Cubic Feet per Year)

Price*		2000	2010	2020	2030
$1.50	Tight	1.2	0.7	0.6	1.1
	Total	13.5	8.7	6.1	4.6
$2.50	Tight	1.4	2.2	4.7	4.6
	Total	16.9	16.0	15.2	11.6
$3.50	Tight	1.5	2.7	5.7	6.2
	Total	17.5	19.2	18.4	15.2
$4.50	Tight	1.5	2.8	5.8	8.9
	Total	17.5	19.8	20.1	19.1
Avg. % Tight		9	13	25	38

*Gulf Coast maximum wellhead price for gas in 1990$ per million BTU.

but tight gas production increases in all cases. Only in the $4.50 per million BTU price case is total production maintained at near current levels through 2030. In that case, tight gas production grows at an average annual compound rate of over 4 percent and is the principal source of new gas supplies needed to maintain total domestic production.

Research and Policy Recommendations for Nonconventional Gas

Significant uncertainty in the resource estimates for nonconventional gas remains, and additional work to remove some of this uncertainty is recommended. Of particular importance is improving estimates of economically recoverable gas, using clearly defined methodology. A cooperative effort among government, industry, and universities might be the best approach.

Tax incentives for production of nonconventional gas are discussed in a separate section.

Sources for Tight Gas Section

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DEVONIAN AND ANTRIM SHALE

Summary

The principal known deposits of gas producing shales are concentrated in the Appalachian, Michigan, and Illinois Basins in the eastern United States and in several Western basins. The Appalachian, Michigan, and Illinois Basin deposits have been characterized by delineating the black and poorer quality gray shale horizons. The 1980 NPC report entitled *Unconventional Gas Sources* provided a detailed analysis of the Appalachian (Devonian) and Michigan Basin (Antrim) shale resource.

Energy and Environmental Analysis (EEA), a consultant to the National Petroleum Council, provided to the NPC their Devonian and Antrim shale resource estimates. These estimates were in turn based upon the 1980 NPC study, Potential Gas Committee estimates published in 1984, and work by consultants. The NPC reviewed the estimates and made revisions based upon the field experience of some of its members. The most significant changes were in the Michigan Basin, where estimates of recoverable resources were about halved.

A comparison of the 1980 NPC study, the EEA estimates, and the 1992 NPC study is shown in Table 3-16. For modeling purposes, estimates have not been included for the Illinois and Western Basins because they are expected to remain undeveloped during the time frame of this study.

TABLE 3-16

DEVONIAN/ANTRIM SHALE RESOURCES
(Trillion Cubic Feet)

	Gas in Place	Recoverable, Current Technology	Recoverable, Advanced Technology
Appalachian Basin			
1980 NPC	225*	37	50
1991 EEA†	248	25	40
1992 NPC	248	27	42
Michigan Basin			
1980 NPC	55	–	–
1991 EEA†	72	21	29
1992 NPC	35	11	15

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* Black shales only.

† Adjusted to January 1991 basis to be consistent with 1992 NPC.

Background

The principal known deposits of gas producing shales are concentrated in the Appalachian, Michigan, and Illinois Basins in the eastern United States and in several Western basins. The Appalachian, Michigan, and Illinois Basin deposits have been characterized by delineating the black and gray shale horizons. The black shales have a higher gas content than the gray shales and are generally believed to be the predominant source beds of the natural gas found in the shales. Although the average total thickness of the shale deposits in the Appalachian Basin is many times greater than that found in the other two basins, a large part of the deposit consists of the poorer quality gray shales.

Prior Estimates of Resource

Studies of the Devonian Shale resource have been made by the National Petroleum Council, the U.S. Geological Survey, the Potential Gas Committee, the Department of Energy, and others. The Gas Research Institute, Energy and Environmental Analysis, and ICF-Lewin have done extensive work in characterizing the resource quantitatively for drilling and production models.

The 1980 NPC report entitled *Unconventional Gas Sources* provided a detailed analysis of the Appalachian and Michigan Basin Devonian/Antrim shale resource. For the current NPC study, EEA provided its own estimates for review as previously discussed.

The 1980 NPC study estimated the thicknesses of black and gray shales in the Appalachian and Michigan Basins and computed total gas in place based upon the assumption that the black shales contained 0.6 volume of gas per volume of shale and the gray shales 0.1 volume per volume. Both gamma ray logs and inspection of cores were used to measure shale thickness, with the gamma ray logs being considered the more accurate technique. Gas in place estimates for the black shales ranged from 225 TCF as determined by gamma ray logs to about 1,100 TCF as estimated from core sample data. Gas in place estimates for the gray shales ranged from 905 TCF based on logs to about 760 TCF based on samples. These estimates included areas in eight states: Kentucky, Maryland, New York, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

The 1991 EEA and 1992 NPC estimates do not include resources in the Illinois Basin or in basins west of the Mississippi. These areas are discussed subsequently in this section, but are considered to be too speculative for inclusion in the study. The estimates are compared in Table 3-16.

Energy and Environmental Analysis had estimated a total gas in place of 248 TCF in the Appalachian Basin, which was slightly higher than the 1980 NPC estimate of 225 TCF based upon black shales only. The 1980 NPC study estimated higher recoverable resources, both with current and advanced technology, but those estimates were based upon high prices ($9.00 per million BTU in 1979 dollars, or about $16 per million BTU in 1991 dollars).

The review of the EEA estimates by the National Petroleum Council resulted in minor increases to recoverable resources in the Appalachian Basin and more significant reductions to recoverable resources in the Michigan Basin. These changes are discussed in detail in the following pages.

Methodology of Current Study of Devonian Shale Resources

The EEA data for Devonian shale in the Appalachian Basin encompasses 30 subdivisions, or "cells." EEA's 1991 descriptions of the cells are shown in Table 3-17. The cells are bounded by degrees of latitude and longitude, and each cell encompasses parts of two or more counties. Most of the cells represent areas of eastern Kentucky, southeastern Ohio and West Virginia, and a small area of Virginia where shale gas has been and is being produced. These areas have high potential for future production. Three of the cells cover much larger areas than the average size formulated by EEA, and describe Rhinestreet/Marcellus shales that are either shallow, intermediate, or deep and cover the entire Appalachian Basin. The data for the latter three cells are more speculative, and the gas is estimated to be more costly to recover.

Columbia Natural Resources (CNR) voluntarily supplied Devonian shale production data from wells in counties of West Virginia, Ohio,

TABLE 3-17

DESCRIPTION OF APPALACHIAN DEVONIAN SHALE CELLS PROVIDED BY ENERGY AND ENVIRONMENTAL ANALYSIS, INC. IN 1991

							Current Technology			Advanced Technology			
ERM Cell No	Drill-able Area (Sq Mi)	Spac-ing (Ac)	Sites	Succ Wells	Succ Rate	All Zone GIP BCF	Per Well Recov MMCF	Cell Recov BCF*	Recov Factor	Per Well Recov MMCF	Cell Recov BCF*	Recov Factor	Adv: Current Improve-ment
1	482	160	1,928	1,697	0.88	828	26.5	45.0	0.05	42.4	72.0	0.09	1.60
2	499	160	1,998	1,758	0.88	1,621	83.5	146.8	0.09	133.6	234.9	0.14	1.60
3	609	160	2,436	2,144	0.88	2,246	70.8	151.8	0.07	113.3	242.9	0.11	1.60
4	587	160	2,348	2,066	0.88	2,356	101.7	210.1	0.09	162.7	336.2	0.14	1.60
5	493	160	1,974	1,737	0.88	2,756	376.3	653.6	0.24	602.1	1045.8	0.38	1.60
6	586	160	2,344	2,063	0.88	2,664	122.3	252.3	0.09	195.7	403.7	0.15	1.60
7	601	160	2,405	2,116	0.88	2,364	71.6	151.5	0.06	114.6	242.4	0.10	1.60
8	511	160	2,043	1,798	0.88	4,501	404.7	727.7	0.16	647.5	1164.2	0.26	1.60
9	171	160	684	602	0.88	820	314.6	189.4	0.23	503.4	303.0	0.37	1.60
10	437	160	1,748	1,538	0.88	1,870	109.0	167.6	0.09	174.4	268.2	0.14	1.60
11	528	160	2,111	1,858	0.88	1,804	52.9	98.3	0.05	84.6	157.3	0.09	1.60
12	379	160	1,517	1,335	0.88	3,801	525.5	701.5	0.18	840.8	1122.5	0.30	1.60
13	325	160	1,301	1,145	0.88	1,231	187.6	214.8	0.17	300.2	343.7	0.28	1.60
14	470	160	1,878	1,653	0.88	3,522	358.2	592.1	0.17	573.1	947.4	0.27	1.60
15	318	160	1,272	1,119	0.88	2,722	589.7	659.9	0.24	943.5	1055.8	0.39	1.60
16	470	160	1,880	1,654	0.88	2,515	161.5	267.1	0.11	258.4	427.4	0.17	1.60

TABLE 3-17 (Continued)

							Current Technology			Advanced Technology			
ERM Cell No	Drill-able Area (Sq Mi)	Spac-ing (Ac)	Sites	Succ Wells	Succ Rate	All Zone GIP BCF	Per Well Recov MMCF	Cell Recov BCF*	Recov Factor	Per Well Recov MMCF	Cell Recov BCF*	Recov Factor	Adv: Current Improve-ment
17	531	160	2,124	1,869	0.88	2,369	25.8	48.2	0.02	41.3	77.2	0.03	1.60
18	459	160	1,838	1,617	0.88	2,844	495.3	800.9	0.28	792.5	1281.4	0.45	1.60
19	509	160	2,034	1,790	0.88	2,944	313.5	561.2	0.19	501.6	897.9	0.30	1.60
20	853	160	3,411	3,002	0.88	1,822	106.4	319.4	0.18	170.2	511.1	0.28	1.60
21	1,278	160	5,111	4,498	0.88	2,710	97.4	438.1	0.16	155.8	701.0	0.26	1.60
22	1,065	160	4,260	3,749	0.88	7,392	238.4	893.8	0.12	381.4	1,430.0	0.19	1.60
23	939	160	3,757	3,306	0.88	3,121	86.8	287.0	0.09	138.9	459.1	0.15	1.60
24	703	160	2,814	2,476	0.88	4,466	156.2	386.8	0.09	249.9	618.8	0.14	1.60
25	1,792	160	7,168	6,308	0.88	6,962	52.5	331.2	0.05	84.0	529.9	0.08	1.60
26	2,426	160	9,705	8,540	0.88	10,001	63.5	542.3	0.05	101.6	867.7	0.09	1.60
27	949	160	3,798	3,342	0.88	2,830	23.1	77.2	0.03	37.0	123.5	0.04	1.60
28†	17,618	160	70,473	62,016	0.88	49,426	80.0	4,961.3	0.10	128.0	7,938.0	0.16	1.60
29†	21,099	160	84,395	74,268	0.88	51,698	70.0	5,198.8	0.10	112.0	8,318.0	0.16	1.60
30†	24,295	160	97,180	85,518	0.88	61,783	72.0	6,157.3	0.10	115.2	9,851.7	0.16	1.60
Totals	**81,984**		**327,934**	**288,582**		**247,989**	**90.9**	**26,233**	**0.11**	**145.4**	**41,972**	**0.17**	**1.60**
Cells 1-27	**18,972**		**75,886**	**66,780**		**85,082**	**148.5**	**9,915**	**0.12**	**237.6**	**15,865**	**0.19**	**1.60**
Cells 28-30	**63,012**		**252,048**	**221,802**		**162,907**	**73.6**	**16,317**	**0.10**	**117.7**	**26,108**	**0.16**	**1.60**

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* Cell recoveries are on a January 1, 1986 basis, the starting date for Hydrocarbon Model runs. Adjusted to a January 1, 1991 basis, total cell recoveries would be about 25,300 BCF and 40,000 BCF for the base and advanced cases, respectively.

† Cells 28-30 contain Rhinestreet Marcellus interval resources.

Kentucky, and Virginia for use by the NPC in verifying the EEA basis. The EEA cell outlines were overlaid on state maps to determine the counties or portions of counties included in each cell.

The CNR data[1] are based upon 1,621 wells drilled in 17 counties and are shown in Table 3-18. The wells are divided into two categories, "Old" and "New," with the old wells being completed before 1971 and the new ones from 1971 through the present. CNR's gas-in-place estimates are based upon DOE studies completed in 1983 to 1985.[2] Estimated ultimately recoverable reserves from each well are based on actual well performance up to the present and estimated future recovery. Recoveries range from about 12 percent up to 50 percent of the estimated gas in place for the old wells and from 2.5 percent up to about 14 percent for the new wells. These recoveries are estimated based upon 120 acre spacing. Ultimate recoveries per well range from about 0.2 BCF to 1.1 BCF for the old wells (averaging about 0.6 BCF) and from about 0.05 BCF to about 0.3 BCF for the new wells (averaging about 0.2 BCF). Most of the new wells are infill, and one possible explanation for the lower recovery is pressure depletion, which has been evident in many cases. Table 3-18 also shows averages for all wells (old and new) drilled by CNR in each county.

The National Petroleum Council made several comparisons of the EEA and CNR data. In general, the averages of the estimated recoveries of old and new wells drilled in a given EEA cell compared reasonably well with EEA's estimates. In some cells, there were sufficient differences to justify changing EEA's estimates to reflect the CNR results.

For the 1992 NPC study, well recoveries in several cells have been revised as a result of the CNR comparisons. These revisions increased the estimated recoverable gas in the base case by about 1.3 TCF and reduced the costs of recovery in lower cost cells, which comprise about one fourth of the total recoverable resources. Table 3-19 delineates the Devonian shale cells used in the NPC Reference Cases, including the revised well recoveries.

The resource estimates for Appalachian Devonian shale exclude areas that have been heavily drilled. The effects of pressure depletion that were observed by CNR at many of its new wells should therefore be absent. CNR had observed that "field" pressure had dropped as much as several hundred pounds (from around 600 to about 350 pounds per square inch) over several decades of gas production.

Advanced Technology

The forecasts of recoverable resources based upon current technology are increased to allow for advances in technology such as horizontal drilling and better fracturing. Advanced technology is phased in over 20 years ending in 2010, and is the official NPC estimate of recoverable resources. A "second generation" of advanced technology begins in 2011 and is completed in 2030, and is used in sensitivity runs to the year 2030.

Antrim (Michigan Basin) Shale

The Antrim shale areas of Michigan have been active in the last several years as drillers have responded to tax credits extended in 1990 legislation. Most of the drilling has been done by independents. The 1991 EEA gas-in-place estimate was 72 TCF. Of that, about 21 TCF was estimated to be recoverable with current technology and about 29 TCF with advanced technology.

During the current NPC study, new information was supplied to the NPC by one of its members, indicating that the area that would be productive for Antrim shale gas was overstated in EEA's estimate. Subsequently, EEA modified the Hydrocarbon Supply Model to reflect the new information. Drillable area was reduced from 34,000 square miles to about 17,000; gas in place from about 72 TCF to about 35 TCF; and recoverable gas from 21 TCF to 11 TCF with current technology, and from 29 TCF to 15 TCF with advanced technology.

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[1] Letter from Stephen E. Eads, Vice President, Planning and Marketing, Columbia Natural Resources, to Ken Baum, Arco Oil and Gas Company and Joseph B. Corns, Amoco Corporation, May 16, 1991.

[2] Technically Recoverable Devonian Shale Gas in Ohio, DOE/MC/19239-1025, July 1983; Technically Recoverable Devonian Shale Gas in West Virginia, DOE/MC/19239-1750, December 1984; Technically Recoverable Devonian Shale Gas in Kentucky, DOE/MC/19239-1834, May 1985.

TABLE 3-18

NPC SHALE STUDY
WELL DATA SUPPLIED BY COLUMBIA NATURAL RESOURCES *

Well Class:†		Old			New			Total		
County	State	No. Wells	Average Ult. Rec. MMCF	Recovery %	No. Wells	Average Ult. Rec. MMCF	Recovery %	No. Wells	Average Ult. Rec. MMCF	Recovery %
Floyd	KY	186	1,064	31.00	10	310	9.00	196	1,027	29.90
Knott	KY	42	440	18.10	13	61	2.50	55	350	14.40
Letcher	KY	14	290	11.90	0	----	-----	14	290	11.90
Magoffin‡	KY	5	680	-------	0	----	-----	5	680	19.80
Martin	KY	202	808	23.50	83	233	6.80	285	641	18.70
Pike	KY	143	589	13.30	5	230	5.20	148	577	13.00
Lawrence	OH	13	500	35.30	24	40	2.80	37	202	14.20
Licking	OH	4	325	50.00	0	----	-----	4	325	50.00
Meigs	OH	16	190	29.20	21	50	7.70	37	110	17.00
Buchanan§	VA	1	520	-------	8	94	3.80	9	141	5.80
Wise§	VA	0	-----	-------	7	293	12.00	7	293	12.00
Kanawha	WV	2	432	19.06	18	214	9.44	20	236	10.41
Lincoln	WV	227	713	17.32	18	294	7.14	245	682	16.57
Logan	WV	112	697	27.19	0	-----	-----	112	697	27.19
Mingo	WV	181	547	21.34	24	255	9.95	205	513	20.00
Roane	WV	0	-----	-------	31	309	13.63	31	309	13.63
Wayne	WV	197	518	12.59	14	104	2.53	211	490	11.93
Total/Average		**1,345**	**554**	**23.83**	**276**	**191**	**7.11**	**1,621**	**445**	**18.03**

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* See reference 1 for methodology.

† Old Wells: Completed Prior to 1971. New Wells: Completed 1971 to present.

‡ Utilized Floyd County, Kentucky GIP.

§ Utilized Letcher County, Kentucky GIP.

TABLE 3-19

DESCRIPTION OF MODIFIED APPALACHIAN DEVONIAN SHALE CELLS USED IN NPC REFERENCE CASES

								Current Technology			Advanced Technology			
ERM Cell No	Drillable Area (Sq Mi)	Depth (Ft.)	Spacing (Ac)	Sites	Succ Wells	Succ Rate	All Zone GIP BCF	Per Well Recov MMCF	Cell Recov BCF	Recov Factor	Per Well Recov MMCF	Cell Recov BCF	Recov Factor	Adv: Current Improvement
1	482	2,410	160	1,928	1,697	0.88	828	26.5	45.0	0.05	42.4	72.0	0.09	1.60
2	499	3,468	160	1,998	1,758	0.88	1,621	83.5	146.8	0.09	133.6	234.9	0.14	1.60
3	609	5,125	160	2,436	2,144	0.88	2,246	70.8	151.8	0.07	113.3	242.9	0.11	1.60
4	587	6,788	160	2,348	2,066	0.88	2,356	101.7	210.1	0.09	162.7	336.2	0.14	1.60
5	493	1,465	160	1,974	1,737	0.88	2,756	376.3	653.6	0.24	602.1	1045.8	0.38	1.60
6	586	3,791	160	2,344	2,063	0.88	2,664	122.3	252.3	0.09	195.7	403.7	0.15	1.60
7	601	5,380	160	2,405	2,116	0.88	2,364	250.0*	529.0	0.22	400.0*	846.4	0.36	1.60
8	511	2,093	160	2,043	1,798	0.88	4,501	404.7	727.7	0.16	647.5	1164.2	0.26	1.60
9	171	3,253	160	684	602	0.88	820	400.0*	240.8	0.29	640.0*	385.3	0.47	1.60
10	437	4,036	160	1,748	1,538	0.88	1,870	200.0*	307.6	0.16	320.0*	492.2	0.26	1.60
11	528	5,250	160	2,111	1,858	0.88	1,804	150.0*	278.7	0.15	240.0*	445.9	0.25	1.60
12	379	2,136	160	1,517	1,335	0.88	3,801	525.5	701.5	0.18	840.8	1122.5	0.30	1.60
13	325	3,741	160	1,301	1,145	0.88	1,231	500.0*	572.5	0.47	800.0*	916.0	0.74	1.60
14	470	2,950	160	1,878	1,653	0.88	3,522	358.2	592.1	0.17	573.1	947.4	0.27	1.60
15	318	3,430	160	1,272	1,119	0.88	2,722	589.7	659.9	0.24	943.5	1055.8	0.39	1.60
16	470	3,100	160	1,880	1,654	0.88	2,515	161.5	267.1	0.11	258.4	427.4	0.17	1.60

TABLE 3-19 (Continued)

								Current Technology			Advanced Technology			
ERM Cell No	Drillable Area (Sq Mi)	Depth (Ft.)	Spacing (Ac)	Sites	Succ Wells	Succ Rate	All Zone GIP BCF	Per Well Recov MMCF	Cell Recov BCF	Recov Factor	Per Well Recov MMCF	Cell Recov BCF	Recov Factor	Adv: Current Improvement
17	531	5,980	160	2,124	1,869	0.88	2,369	25.8	48.2	0.02	41.3	77.2	0.03	1.60
18	459	2,833	160	1,838	1,617	0.88	2,844	495.3	800.9	0.28	792.5	1281.4	0.45	1.60
19	509	4,730	160	2,034	1,790	0.88	2,944	300.0*	537.0	0.18	480.0*	859.2	0.29	1.60
20	853	2,204	160	3,411	3,002	0.88	1,822	106.4	319.4	0.18	170.2	511.1	0.28	1.60
21	1,278	1,698	160	5,111	4,498	0.88	2,710	97.4	438.1	0.16	155.8	701.0	0.26	1.60
22	1,065	1,276	160	4,260	3,749	0.88	7,392	238.4	893.8	0.12	381.4	1,430.0	0.19	1.60
23	939	5,565	160	3,757	3,306	0.88	3,121	150.0*	495.9	0.16	240.0*	793.4	0.25	1.60
24	703	825	160	2,814	2,476	0.88	4,466	156.2	386.8	0.09	249.9	618.8	0.14	1.60
25	1,792	5,412	160	7,168	6,308	0.88	6,962	52.5	331.2	0.05	84.0	529.9	0.08	1.60
26	2,426	7,029	160	9,705	8,540	0.88	10,001	63.5	542.3	0.05	101.6	867.7	0.09	1.60
27	949	6,481	160	3,798	3,342	0.88	2,830	23.1	77.2	0.03	37.0	123.5	0.04	1.60
28	17,618	2,699	160	70,473	62,016	0.88	49,426	80.0	4,961.3	0.10	128.0	7,938.0	0.16	1.60
29	21,099	5,645	160	84,395	74,268	0.88	51,698	70.0	5,198.8	0.10	112.0	8,318.0	0.16	1.60
30	24,295	7,894	160	97,180	85,518	0.88	61,783	72.0	6,157.3	0.10	115.2	9,851.7	0.16	1.60
Totals	**81,984**			**327,934**	**288,582**		**247,989**	**95.4**	**27,525†**	**0.11**	**152.6**	**44,039†**	**0.18**	**1.60**
Cells 1-27	**18,972**			**75,886**	**66,780**		**85,082**	**167.8**	**11,207**	**0.13**	**268.5**	**17,932**	**0.21**	**1.60**
Cells 28-30	**63,012**			**252,048**	**221,802**		**162,907**	**73.6**	**16,317**	**0.10**	**117.7**	**26,108**	**0.16**	**1.60**

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* Recovery per well has been revised from original EEA basis.

† Cell recoveries are on a January 1, 1986 basis, the starting date for Hydrocarbon Model runs. Adjusted to a January 1, 1991 basis, total recoverable resources are about 26,600 BCF with base technology and 42,400 with advanced technology.

Descriptions of the revised Antrim shale cells used in the NPC Reference Cases are shown in Table 3-20.

Recent information[3,4] obtained from newer wells in the Antrim shale indicates that gas-in-place and recoverable resources for the Antrim cells could be substantially higher than the NPC's estimates. The use of special pumps to dewater the shale and reduce bottom hole pressure allows desorption of gas to take place at higher rates and is expected to increase ultimate recoveries. The Gas Research Institute is following these developments.

Other Gas Shale Basins

Outside of Michigan and Appalachia, shale gas activity has been minimal. The most widely known, but still not well understood basins, are in Illinois (Illinois Basin), Texas (Fort Worth Basin, Barnett Shale), Oklahoma (Hunton/Woodford Shales), and Rocky Mountains (Green River, Niobrara, Pierre, and Mancos Shales).

These shale basins have been minimally explored, and this resource is not well defined. From rough estimates of the quality of the shale, and formation areas and thicknesses, the NPC has estimated gas in place and recoverable resources in Table 3-21. The recoverable resources are significant, but the limited knowledge of these areas available at this time precludes inclusion of the data in gas supply projections.

Reserve Additions and Production of Devonian/Antrim Shale Gas

Projected reserve additions and production of Devonian/Antrim shale gas are shown in Table 3-22. In NPC Reference Case 1, reserve additions are estimated to increase from the 1990 level of 0.5 TCF to about 0.9 TCF in 2000, before declining to 0.5 TCF in 2010. In NPC Reference Case 2, reserve additions are projected to peak at about 0.8 TCF in 2005 but decline to 0.1 TCF by 2010.

In both cases, production of Devonian/Antrim shale gas is estimated to increase from the present level of about 0.2 TCF to 0.4 to 0.5 TCF over the 2000-2010 period.

Model Runs Through 2030

For model runs through 2030, a "second generation" of advance technology was added to recoverable resources, as shown in Table 3-23.

Results of the model runs showed production of Devonian/Antrim shale gas declining after 2010 in the runs at $1.50 and $2.50 per million BTU in 1990 dollars, but increasing in the $3.50 and $4.50 per million BTU runs (Table 3-24).

COALBED METHANE

Summary

The National Petroleum Council reviewed information on coalbed methane activity and resource estimates in order to update the 1980 NPC report, *Unconventional Gas Sources*, and to assess coalbed methane's potential contribution to future U.S. gas production.

Over the last 12 years, there has been a remarkable increase in the production and utilization of coalbed methane. Most of this increase has taken place since 1986. It has been due principally to the stimulus of the Section 29 tax credit and early exploration successes in the San Juan and Black Warrior Basins. These drilling programs, by several operators, took coalbed methane production from an experimental curiosity to an established performer in a few short years. Coalbed methane production rose from 40 BCF in 1988 to 196 BCF in 1990 and 348 BCF in 1991. Coalbed methane accounted for about 2 percent of annual U.S. dry gas production in 1991. Coalbed methane wells drilled increased from 736 in 1988 to 2,414 in 1990.

The NPC reviewed the coal basins of the lower-48 states utilizing both proprietary and public data to determine the potential of these basins to produce methane in commercial quantities from the coals contained therein.

Several basins projected to contain substantial reserves in previous studies were

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[3] Kuuskraa, V. A., D. E. Wicks, and J. L. Thurber, "Geologic and Reservoir Mechanisms Controlling Gas Recovery from the Antrim Shale," paper presented at the 1992 Annual Meeting of the Society of Petroleum Engineers, Washington, D.C., October 5–8.

[4] Kuuskraa, V. A., report prepared for the Gas Research Institute by Advanced Resources International, Arlington, VA: September 1992.

TABLE 3-20

MICHIGAN BASIN ANTRIM SHALE FINAL RESOURCE AND CELL DESCRIPTIONS

							Current Technology			Advanced Technology			
Cell	Drill-able Area (Sq Mi)	Avg. Depth (Ft)	160-Acre Sites	No. Succ Wells @ 87%	G.I.P. (BCF)	G.I.P. Per Sq.Mi. (BCF)	Avg. Recov. Factor	Tech Recovery Per Well (MMCF)	Cell Re-covery (BCF)	Avg. Recov. Factor	Tech Recovery Per Well (MMCF)	Cell Re-covery (BCF)	Adv: Current Improve-ment
1	3,040	1,465	12,360	10,579	6,628	2.18	0.42	262	2,772	0.59	367	3,883	1.40
2	3,094	2,351	12,376	10,767	8,398	2.71	0.29	226	2,433	0.41	317	3,413	1.40
3	1,660	2,685	6,640	5,777	4,561	2.75	0.28	224	1,294	0.40	314	1,814	1.40
4	2,152	1,999	8,608	7,480	4,339	2.02	0.26	150	1,123	0.36	210	1,573	1.40
5	7,236	1,032	28,944	25,181	10,669	1.47	0.31	132	3,324	0.44	185	4,659	1.40
Total	**17,182**		**68,728**	**59,793**	**34,595**	**2.01**	**0.32**	**183**	**10,947**	**0.44**	**257**	**15,341**	

TABLE 3-21

OTHER SHALE BASIN DATA

Basin	Area (Square Miles)	Gas Content BCF/Section	Recovery/ Well (MMCF)	Total Gas in Place (BCF)	Estimated Ultimate Recovery @ 12% (BCF)
Fort Worth	1,000	5	250-500	5,000	600
Hunton/ Woodford	1,000	5	500-1,000	5,000	600
Green River	12,000	5	500-1,000	60,000	7,200
Niobrara/ Pierre	6,000	10	500-1,000	60,000	7,200
Mancos	1,000	10	500-1,000	10,000	1,200
Illinois	32,000	5	500-1,000	160,000	19,200
Totals				**300,000**	**36,000**

TABLE 3-22

ESTIMATED DEVONIAN/ANTRIM SHALE RESERVE ADDITIONS AND PRODUCTION

(Trillion Cubic Feet per Year)

	1990	1995	2000	2005	2010
Reserve Additions					
NPC Reference Case 1					
Shale Gas	0.5	0.5	0.9	0.5	0.5
Total Gas	18.5	15.1	18.7	22.2	22.5
NPC Reference Case 2					
Shale Gas	0.5	0.4	0.7	0.8	0.1
Total Gas	18.5	11.8	15.5	17.9	18.3
Production					
NPC Reference Case 1					
Shale Gas	0.2	0.3	0.5	0.5	0.5
Total Gas	17.3	17.8	18.3	20.0	20.5
NPC Reference Case 2					
Shale Gas	0.2	0.3	0.4	0.5	0.4
Total Gas	17.3	17.1	16.0	17.4	17.4

TABLE 3-23

RECOVERABLE RESOURCES JANUARY 1, 1991 BASIS (Trillion Cubic Feet)

	Current Technology	1990 to 2010 Advanced Technology	Second Generation Advanced Technology
Appalachian/ Antrim	37	57	73

TABLE 3-24

PRODUCTION OF DEVONIAN/ANTRIM SHALE GAS (Trillion Cubic Feet)

Run*	2000	2010	2030
$1.50	0.34	0.29	0.16
$2.50	0.39	0.50	0.51
$3.50	0.45	0.60	0.91
$4.50	0.45	0.65	1.02

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* Maximum Gulf Coast wellhead price of gas in 1990$ per million BTU. In some runs, prices are well below the maximum up to 2010. The runs are discussed in greater detail in Chapter Two.

downgraded to lesser potential based on more recent information; in some cases these basins were excluded from the Hydrocarbon Model input. Other basins were upgraded to higher levels of resources based on production data from the last few years, or new information on exploration successes or increased gas contents of the coals. There is still uncertainty about the productivity of the coals in many of the basins reviewed, because they have not been tested extensively.

The 1992 NPC assessment of coalbed methane resources in the lower-48 states is summarized in Table 3-25.

TABLE 3-25

COALBED METHANE RECOVERABLE RESOURCES IN THE LOWER-48 STATES (Trillion Cubic Feet)

	Recoverable Resources	
Basin	Current Technology	Advanced Technology
San Juan	22	33
Black Warrior	7	10
Piceance	17	27
Raton and Misc. Rockies	8	12
Northern Appalachian	9	15
Total Undiscovered Resources	**62**	**98**

Coalbed methane undiscovered recoverable resources total 62 TCF with current technology and 98 TCF with advanced technology. These resource numbers are on a January 1, 1991 basis; Hydrocarbon Supply Model inputs are on a January 1, 1986 basis to allow the model to generate historical data, and the equivalent resources are 67 TCF with current technology and 106 TCF with advanced technology.

Prior Estimates of Coalbed Methane Potential

In 1980, the NPC report on unconventional gas sources estimated recoverable coalbed methane potential at 2 to 5 TCF assuming a price of $2.50 per MCF. Other estimates in 1979 and 1980 by the Gas Research Institute, Kuuskraa, Meyer, and others ranged from 10 to 60 TCF, with one estimate as high as 487 TCF. Since then, several studies conducted by a variety of governmental and private organizations have updated these earlier estimates of coalbed methane potential. Some of these studies reported only gas in place while others included estimates of recoverable resources as well. From 1988 to 1991, the Potential Gas Committee, the Department of Energy, the Gas Research Institute, and Enron all conducted studies of coalbed methane potential. These updates resulted in estimates of recoverable gas in the lower-48 states ranging from 47 to 100 TCF. The 1992 NPC estimates fall within this range.

Study Objectives

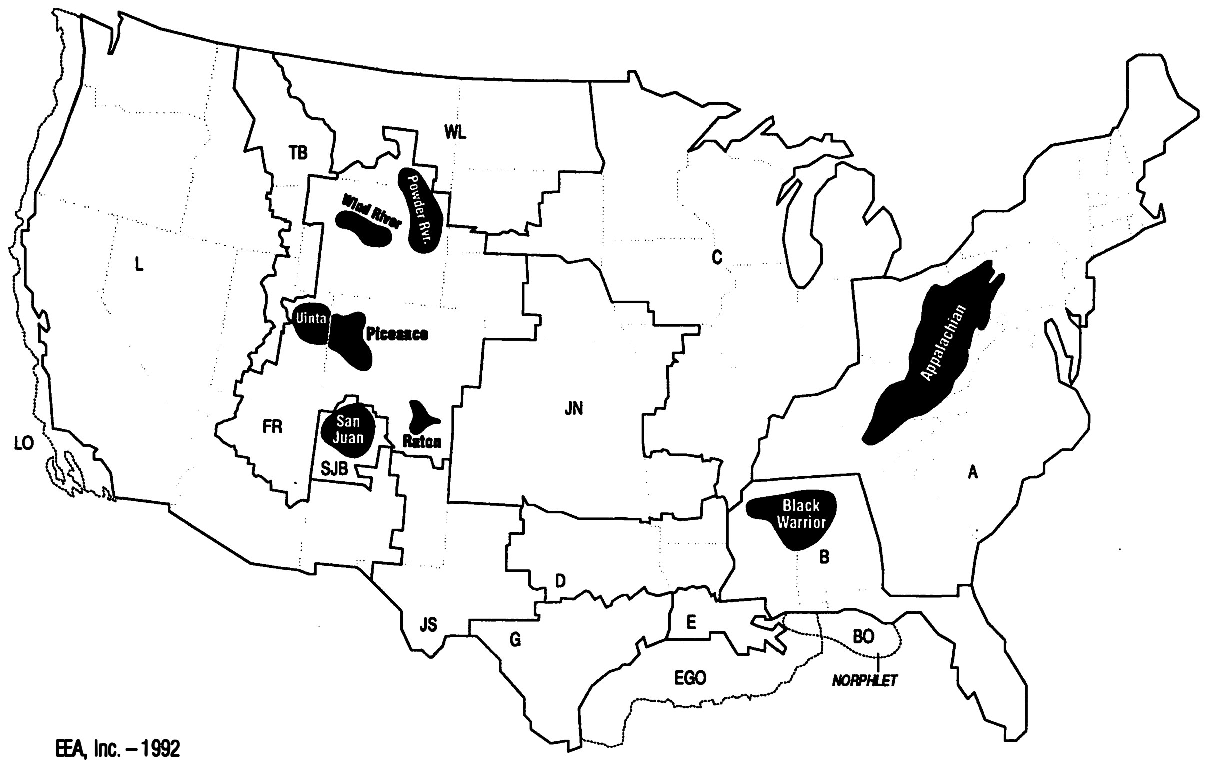
The National Petroleum Council reviewed 20 coal basins in the lower-48 states for potential coalbed methane reserves and production for inclusion in the resource model. A map showing the locations of the principal basins with coalbed methane potential is shown in Figure 3-2. These reviews utilized well logs and production data where available and built on the previous estimates of the Potential Gas Committee, the Department of Energy, and the Gas Research Institute. The coals in these basins range in age from Paleozoic to Tertiary and in depth from the surface to greater than 10,000 feet. Coal rank varies from subbituminous to anthracite.

Although coalbed methane production is a relatively new source of gas, there has been a dramatic increase in drilling and production since 1989 in the San Juan and Black Warrior Basins due to the stimulus of the Section 29 federal tax credit. The production increase from these two basins has been well beyond prior expectations. As a result of this drilling, there is currently gas production shut-in in the San Juan Basin due to the lack of pipeline capacity and low prices. By the end of 1992, new pipelines transporting gas out of the San Juan Basin will increase capacity from that area to almost one TCF per year. In addition, there have been increases in drilling and production in the Piceance Basin and other basins in 1990 and 1991.

Historical Trends and Future Expectations for Coalbed Methane Production

Development of coalbed methane resources has accelerated during the past three years because of tax incentives and a better understanding of the resource and technology requirements to recover the gas. Although proved reserves of coalbed methane at the end of 1990 were only about 5 TCF, the NPC estimates that 62 TCF of coalbed methane are technically recoverable with current technology and about 98 TCF with advanced technology. Estimated total gas in place is 300 to 400 TCF.

The major unknowns for the coalbed methane resource and reserve estimates are: (1) whether the Section 29 tax credit will be extended to new wells drilled after 1992, and if so will it stimulate drilling and production as much



EEA, Inc. – 1992

Figure 3-2. NPC Lower-48 Coalbed Methane Areas.

as it has in the last two to three years (the tax credit was not extended in 1992 legislation, and it was not applied for drilling after 1992 in model runs for NPC Reference Cases 1 and 2); (2) whether one or more other coal basins will become as productive as the Black Warrior or San Juan Basins; and (3) whether there will be an unexpected technological breakthrough that improves well productivity and makes otherwise marginal or uneconomic basins exploitable. Positive developments in these areas could increase estimated recoverable resources of coalbed methane by 10 to 30 TCF.

If ownership problems could be resolved and the resource aggressively pursued, the Appalachians could provide significant additional production increases over the next ten to twenty years. The Piceance and Greater Green River Basins could also provide some increased coalbed methane production if the coals are developed in conjunction with the interbedded tight gas sands. A few operators are already commingling coal and tight sands production in parts of the Piceance Basin.

Although we know a great deal about the thicknesses and distribution of the coals in the basins reviewed, the major uncertainty governing our estimates of the resource in each basin is the gas content of the coals. In the heavily drilled and productive basins there are enough gas content data to make reliable estimates of the gas in place. However, in the majority of the basins, few if any gas content measurements are available, which makes estimating the potential resource there much more difficult. In terms of resource recoverability, the dominant unknown is the permeability and gas deliverability of the coals. The known variations within one basin or even within one field can be several orders of magnitude. This adds to the difficulty and uncertainty of estimating production rates and recoverability over the long term.

Current Issues and Uncertainties

Coalbed methane resources are less sensitive to gas prices if the operator can utilize Section 29 tax credits. However, if the operator cannot use these tax credits (many companies are now in that position due to the Alternative Minimum Tax and/or low profits), many coalbed methane projects become marginal or uneconomic and are extremely sensitive to even small gas price fluctuations. This is especially true in the Midcontinent and Rocky Mountain areas where major markets are distant and transportation costs high. The exceptions are the San Juan Basin and parts of the Black Warrior Basin where some wells are economic without the tax credit. In areas of limited pipeline access, coalbed methane projects often require large up-front investments to prove up sufficient reserves to justify construction of new pipelines into these areas. This often makes payouts very long and increases the potential risks to unacceptable levels for investors, even though the projects are geologically and technically sound.

In light of the above caveats, the NPC has made its best estimate of the coalbed methane resource and reserves from the most recent data available. The following is a basin by basin summary of the data used and the results generated from the Hydrocarbon Supply Model runs conducted by Energy and Environmental Analysis, Inc.

Basin Summaries

The factors required for input into the Enhanced Recovery Module of the model, where coalbed methane calculations are made, were an estimate of the gas in place; recovery per well of the gas in place; the number of wells per section; geological and combined success rate estimates; future investment patterns; operating costs per well; and production figures for water, carbon dioxide, and natural gas liquids. These parameters were obtained from published production and geological reports as well as from proprietary information provided by some operators in specific basins. In basins where information was scarce, not current, or unavailable, best-guess estimates were made, or several basins were lumped together and an estimate was made of total recoverable resources.

The basins reviewed in detail were the San Juan, the Black Warrior, the Piceance, the Raton, the Uinta, the Greater Green River, the Powder River, the Wind River, and the Northern Appalachian Basins. Also reviewed were the Cherokee and Forrest City Basins and the Central Appalachian Basin, but these were not included in the Hydrocarbon Model because of their relatively small potential. Other basins are discussed which may have potential but for which there are insufficient data to include in the model.

Basins Included in the Hydrocarbon Model

San Juan Basin

Geologic Setting

The San Juan Basin is located in northwestern New Mexico and southwestern Colorado. Productive coals occur in the Cretaceous Fruitland Formation. Deeper coals in the Cretaceous Menefee Formation also have significant potential, but have not yet been developed.

Conditions in the basin are optimal for coalbed methane production. The coals are relatively thick and laterally continuous as well as mature. Basin hydrodynamics, permeability, and fracture patterns all enhance production. Most of the primary coals occur at drill depths of less than 4,000 feet.

Activity and Production

The San Juan Basin is the most productive coalbed methane basin in the United States. Nearly 2,000 wells have been drilled, with average production rates of 200 thousand cubic feet of gas per day (MCF/D) for the overpressured areas and 70 MCF/D for the normally pressured areas. At least several hundred of the drilled wells have not yet been completed. Reported production rates in some of the best wells exceed 10 million cubic feet per day (MMCF/D).

Associated water production averages 90 to 100 barrels per day in the best areas and 3 to 10 barrels per day in the less productive areas. In a few cases where gas production is in the 10 to 20 MMCF/D range, water production has exceeded 1,000 barrels per day. There is no production of hydrocarbon liquids. Carbon dioxide production averages 5 to 6 percent. Well costs are typically $400,000 to $500,000 for a completed producer. Operating costs run from $20,000 to $50,000 per well per year, half of which is for water disposal.

Hydrocarbon Model Assumptions

The combined Fruitland and Menefee coalbed methane resource is estimated to be 77 TCF in place. Technically recoverable resource with current technology is estimated to be 22 TCF, and 33 TCF is forecast to be recoverable with advanced technology. These estimates are on a January 1, 1991 basis, while model inputs are on a January 1, 1986 basis and are 25 and 39 TCF, respectively. The Fruitland coal areas in the basin were divided into ten cells for modeling purposes. The average recovery per well with current technology is expected to be 1.0 BCF with a range of about 0.1 to 3.6 BCF. Menefee coals, which are estimated at 30 TCF in place, were divided into seven major cells with a range of recovery per well with current technology from 0.1 to 1.1 BCF with an average of 0.56 BCF. Production from the Menefee coals is not expected to start until the year 2000 when Fruitland production will have declined significantly. Detailed descriptions of the cells used to describe the coals in all of the basins modeled are shown in Tables 3-26 through 3-30.

Black Warrior Basin

Geologic Setting

The Black Warrior Basin, located in northern Alabama and Mississippi, covers approximately 18,000 square miles, and is the southernmost extension of the Appalachian Basin. Productive coals occur in the Pennsylvanian Pottsville formation, which includes the Black Creek, Mary Lee, Pratt, and Cobb coal groups. Coal seam groups or "packets" are generally less than 30 feet thick with gas contents ranging from 50 to 540 standard cubic feet (SCF) per ton. Coals vary in rank from high volatile to low volatile bituminous and occur from about 500 to 4,000 feet in depth.

Activity and Production

The Black Warrior Basin is the most active coalbed methane basin in the United States. Over 3,500 wells have been drilled, with an average production rate of approximately 100 MCF/D. Although coalbed methane wells were drilled throughout most of the 1980s, the phenomenal rise in activity occurred in 1988, in expectation of the expiration of the federal tax credit (the credit was extended to wells drilled through 1992).

Open hole completions are generally used for single zones and cased hole completions for multiple zones. Wells are usually stimulated using hydraulic fracturing, and typically cost around $300,000 for a completed producer. Operating costs run about $15,000 to

TABLE 3-26

DESCRIPTIONS OF COALBED METHANE CELLS* SAN JUAN BASIN FRUITLAND COAL

UTILIZING MULTI ZONE GAS IN PLACE

										CURRENT TECHNOLOGY				ADVANCED TECHNOLOGY				
CELL	AVG DEPTH	APPX TOTAL AREA (SQ MI)	DRILLABLE AREA (SQ MI)	SPACING	MULTI ZONE PER WELL G.I.P. (BCF)	G.I.P. PER SQ. MI. (BCF)	CELL G.I.P. DRILLABLE AREA (BCF)	DRILLING SUCCESS RATE	SUCCESSFUL WELLS	PER WELL RECOV FACTOR	CELL RECOVERY FACTOR	RECOVERY MMCF PER WELL	BCF RECOV	PER WELL RECOV FACTOR	CELL RECOVERY FACTOR	RECOVERY MMCF PER WELL	BCF RECOV	ADV. IMP RATIO
1	3124	443	399	160	7.222	28.888	11,518	80%	1,276	0.50	0.40	3,611	4,607	0.75	0.60	5,417	6,911	1.50
2	2477	296	266	160	5.132	20.528	5,469	80%	852	0.47	0.38	2,412	2,056	0.74	0.59	3,772	3,216	1.56
3	2253	353	318	160	2.555	10.220	3,247	70%	890	0.44	0.31	1,124	1,000	0.72	0.50	1,840	1,636	1.64
4	3095	373	336	160	4.964	19.856	6,666	80%	1,074	0.50	0.40	2,482	2,666	0.75	0.60	3,723	3,999	1.50
5	2169	486	437	160	1.689	6.756	2,955	70%	1,225	0.43	0.30	726	889	0.69	0.48	1,162	1,423	1.60
6	2880	511	460	160	2.071	8.284	3,810	70%	1,288	0.48	0.34	994	1,280	0.74	0.52	1,533	1,973	1.54
7	1224	1,350	1,215	160	0.677	2.708	3,290	60%	2,916	0.27	0.16	183	533	0.43	0.26	292	853	1.60
8	2064	864	778	160	0.702	2.808	2,184	60%	1,866	0.41	0.25	288	537	0.66	0.39	461	859	1.60
9	3529	1,080	972	160	1.893	7.572	7,360	70%	2,722	0.51	0.36	965	2,628	0.76	0.53	1,429	3,890	1.48
10	1292	830	747	160	0.273	1.092	816	60%	1,793	0.29	0.17	79	142	0.46	0.28	127	227	1.60
TOTAL		**6,586**	**5,927**				**47,313**		**15,901**		**0.35**	**1,028**	**16,339**		**0.53**	**1,571**	**24,988**	

TABLE 3-26 (CONTINUED)

DESCRIPTIONS OF COALBED METHANE CELLS* SAN JUAN BASIN MENEFEE COALS†

									CURRENT TECHNOLOGY			ADVANCED TECHNOLOGY			
CELL	AVG DEPTH	APPX TOTAL AREA (SQ MI)	DRILL-ABLE AREA (SQ MI)	SPAC-ING	G.I.P. PER SQ. MI. (BCF)	CELL G.I.P. DRILLABLE AREA (BCF)	DRILLING SUCCESS RATE	SUCCESS-FUL WELLS	RECOV FACTOR	RECOVERY MMCF PER WELL	BCF RECOV	RECOV FACTOR	RECOVERY MMCF PER WELL	BCF RECOV	ADV. IMP RATIO
1‡	5,124	443	399	160	0.288	115	80%	13	0.40	3,605	46	0.60	5,408	69	1.50
2‡	4,477	296	266	160	0.206	55	80%	9	0.38	2,463	21	0.58	3,769	32	1.53
3	4,253	353	318	160	12.855	4,084	70%	1,119	0.31	1,124	1,258	0.51	1,844	2,063	1.64
4‡	5,095	373	336	160	0.200	67	80%	11	0.40	2,513	27	0.60	3,720	40	1.48
5	4,169	486	437	160	8.498	3,717	70%	1,541	0.30	726	1,118	0.48	1,161	1,789	1.60
6	4,880	511	460	160	10.420	4,792	70%	1,620	0.34	994	1,610	0.52	1,531	2,479	1.54
7	3,124	1,350	1,215	160	3.406	4,138	60%	3,668	0.16	183	670	0.26	292	1,072	1.60
8	4,064	864	778	160	3.533	2,747	60%	2,348	0.25	288	675	0.39	460	1,080	1.60
9	5,529	1,080	972	160	9.525	9,258	70%	3,424	0.36	966	3,306	0.53	1,429	4,893	1.48
10	3,292	830	747	160	1.373	1,026	60%	2,255	0.17	79	179	0.28	127	286	1.60
TOTAL		**6,586**	**5,927**			**29,999**		**16,007**	**0.30**	**557**	**8,910**	**0.46**	**862**	**13,804**	**1.55**

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* Recoverable resources shown in this table are stated on a January 1, 1986 basis, which is used for model input.

† Based upon normal pressure SJB Fruitland. Target GIP of 30,000 BCF; Recovery of 8,900 BCF. Added 2,000 feet to drilling depths of Fruitland. Well counts scaled up.

‡ Cells 1, 2, and 4 have been reduced to near zero because few high recovery wells are anticipated in the Menefee coals.

TABLE 3-27

DESCRIPTIONS OF COALBED METHANE CELLS* PICEANCE BASIN

								CURRENT TECHNOLOGY				ADVANCED TECHNOLOGY				
CELL	AVG DEPTH	AREA SQ MI	AVG GIP PER SQ MI	TOTAL GIP BCF	160 ACRE SITES	SUCC. WELLS @ 60%	AVG GIP PER 160	WELL RECOV FACTOR	CELL RECOV FACTOR	RECOV/ WELL (MMCF)	RECOV (BCF)	WELL RECOV FACTOR	CELL RECOV FACTOR	RECOV/ WELL (MMCF)	RECOV (BCF)	ADV: BASE IMP RATIO
1	7,000	186	33	6,037	743	446	8.13	0.359	0.22	2,917	1,300	0.574	0.34	4,667	2,081	1.60
2	9,000	276	33	8,975	1,105	663	8.13	0.381	0.23	3,096	2,052	0.610	0.37	4,953	3,283	1.60
3	8,000	357	28	9,815	1,428	857	6.88	0.372	0.22	2,558	2,191	0.595	0.36	4,092	3,505	1.60
4	12,000	236	28	6,499	945	567	6.88	0.401	0.24	2,757	1,564	0.642	0.38	4,411	2,502	1.60
5	10,000	341	23	7,680	1,365	819	5.63	0.389	0.23	2,188	1,793	0.622	0.37	3,501	2,868	1.60
6	6,000	510	23	11,465	2,038	1,223	5.63	0.343	0.21	1,929	2,359	0.549	0.33	3,087	3,775	1.60
7	5,000	661	18	11,572	2,645	1,587	4.38	0.320	0.19	1,400	2,222	0.512	0.31	2,240	3,555	1.60
8	4,000	1,182	13	14,781	4,730	2,838	3.13	0.286	0.17	894	2,536	0.458	0.27	1,430	4,058	1.60
9	3,000	957	8	7,176	3,827	2,296	1.88	0.228	0.14	428	982	0.365	0.22	684	1,571	1.60
TOTAL		**4,707**		**84,000**	**18,826**	**11,296**		**0.202**	**0.20**	**1,505**	**16,998**		**0.32**	**2,408**	**27,197**	**1.60**

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* Recoverable resources shown in this table are stated on a January 1, 1986 basis, which is used for model input.

TABLE 3-28

DESCRIPTIONS OF COALBED METHANE CELLS* RATON BASIN AND MISCELLANEOUS ROCKIES†

									CURRENT TECHNOLOGY			ADVANCED TECHNOLOGY			
CELL	AVG DEPTH	APPX TOTAL AREA (SQ MI)	DRILL-ABLE AREA (SQ MI)	SPAC-ING	G.I.P. PER SQ. MI. (BCF)	CELL G.I.P. DRILLABLE AREA (BCF)	DRILLING SUCCESS RATE	SUCCESS-FUL WELLS	RECOV FACTOR	RECOVERY MMCF PER WELL	BCF RECOV	RECOV FACTOR	RECOVERY MMCF PER WELL	BCF RECOV	ADV: BASE IMP RATIO
1	3,124	443	399	160	0.288	115	80%	13	0.40	3,605	46	0.60	5,417	69	1.50
2	2,477	296	266	160	0.206	55	80%	9	0.38	2,463	21	0.58	3,772	32	1.53
3	2,253	353	318	160	11.530	3,663	70%	1,003	0.31	1,124	1,128	0.50	1,840	1,846	1.64
4	3,095	373	336	160	0.200	67	80%	11	0.40	2,513	27	0.60	3,723	40	1.48
5	2,169	486	437	160	7.620	3,333	70%	1,381	0.30	726	1,003	0.48	1,162	1,605	1.60
6	2,880	511	460	160	9.346	4,298	70%	1,453	0.34	994	1,444	0.52	1,533	2,227	1.54
7	1,224	1,350	1,215	160	3.054	3,711	60%	3,289	0.16	183	601	0.26	292	960	1.60
8	2,064	864	778	160	3.169	2,464	60%	2,105	0.25	288	606	0.39	461	970	1.60
9	3,529	1,080	972	160	8.542	8,303	70%	3,070	0.36	966	2,965	0.53	1,429	4,387	1.48
10	1,292	830	747	160	1.233	921	60%	2,022	0.17	79	160	0.28	127	257	1.61
TOTAL		**6,586**	**5,927**			**26,930**		**14,356**	**0.30**	**557**	**8,001**	**0.46**	**863**	**12,394**	

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* Recoverable resources shown in this table are stated on a January 1, 1986 basis, which is used for model input.

† Based upon normal pressure SJB Fruitland cells. Target GIP of 27,000 BCF; Base recovery of 8,000 BCF. Same drilling depths, recovery per well, and cell areas as SJB Fruitland. Number of wells adjusted to meet target base recovery.

TABLE 3-29

DESCRIPTIONS OF COALBED METHANE CELLS* BLACK WARRIOR BASIN

						CURRENT TECHNOLOGY				ADVANCED TECHNOLOGY				
CELL	DEPTH	ALL ZONE G.I.P. (BCF)	DRILL. AREA (ACRES)	80 ACRE SITES	SUCC WELLS @ 70 %	CELL RECOV (BCF)	PER WELL RECOV (MMCF)	RECOV FACTOR	CALC PROD AREA SQ MI	CELL RECOV (BCF)	PER WELL RECOV (MMCF)	RECOV FACTOR	CALC AREA SQ MI	ADV IMP RATIO
1	1,457	480	33,760	422	295	222	751	0.46	37	351	1,187	0.73	37	1.58
2	1,600	25	2,240	28	20	12	598	0.47	2	19	950	0.74	2	1.59
3	1,913	1,121	56,480	706	494	524	1,060	0.47	62	823	1,665	0.73	62	1.57
4	2,145	1,015	44,640	558	391	465	1,192	0.46	49	740	1,895	0.73	49	1.59
5	2,791	873	64,320	804	563	421	747	0.48	70	647	1,149	0.74	70	1.54
6	2,736	1,490	66,960	837	586	635	1,084	0.43	73	1,016	1,735	0.68	73	1.60
7	3,531	1,325	80,160	1,002	701	467	666	0.35	88	747	1,066	0.56	88	1.60
8	2,081	1,729	133,280	1,666	1,166	484	415	0.28	146	774	664	0.45	146	1.60
9	2,407	5,749	583,360	7,292	5,104	1,609	315	0.28	638	2,574	504	0.45	638	1.60
10	743	553	264,960	3,312	2,318	155	67	0.28	290	247	107	0.45	290	1.60
11	2,903	2,878	373,120	4,664	3,265	704	216	0.24	408	1,126	345	0.39	408	1.60
12	4,124	3,641	434,240	5,428	3,800	892	235	0.24	475	1,427	375	0.39	475	1.60
13	2,000	3,240	184,320	2,304	1,613	1,023	634	0.32	202	1,636	1,014	0.51	202	1.60
TOTAL		**24,120**	**2,321,840**	**29,023**	**20,316**	**7,611**	**375**	**0.32**	**2,540**	**12,128**	**597**	**0.50**	**2,540**	**1.58**

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* Recoverable resources shown in this table are stated on a January 1, 1986 basis, which is used for model input.

TABLE 3-30

DESCRIPTIONS OF COALBED METHANE CELLS* NORTHERN APPALACHIAN BASIN†

								CURRENT TECHNOLOGY				ADVANCED TECHNOLOGY				
CELL	AVG DEPTH	AREA (SQ MI)	CELL GIP (BCF)	80 ACRE SITES	DRILL SUCC RATE	SUCC WELLS AT 80%	GIP PER 80 ACRES (MMCF)	WELL RECOV FACTOR	CELL RECOV FACTOR	TECH RECOV PER WELL (MMCF)	CELL RECOV (BCF)	WELL RECOV FACTOR	CELL RECOV FACTOR	TECH RECOV PER WELL (MMCF)	CELL RECOV (BCF)	ADV: BASE IMP RATIO
1	1,000	5,000	15,000	40,000	0.80	32,000	375	0.40	0.32	150	4,800	0.64	0.51	240	7,680	1.60
2	1,500	2,300	11,500	18,400	0.80	14,720	625	0.40	0.32	250	3,680	0.64	0.51	400	5,888	1.60
3	2,000	500	3,000	4,000	0.80	3,200	750	0.40	0.32	300	960	0.64	0.51	480	1,536	1.60
TOTAL		**7,800**	**29,500**	**62,400**		**49,920**			**0.32**	**189**	**9,440**		**0.51**	**303**	**15,104**	

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* Recoverable resources shown in this table are stated on a January 1, 1986 basis, which is used for model input.

† Based on GRI gas in place and depth maps and estimated recovery factors.

$20,000 per well per year. Associated water production is minimal after initial dewatering.

Total production for 1990 was 36 BCF, an increase of 56 percent over 1989 production. Cumulative production through 1990 was 130 BCF, primarily from eight established fields in the eastern portion of the basin.

Hydrocarbon Model Assumptions

The total coalbed methane resource in the basin is estimated to be 24 TCF in place. Recoverable gas with current technology is expected to be 7 TCF. The basin was divided into 13 cells for modeling. The average recovery per well is 0.4 BCF, assuming a 70 percent success rate, with a range of 0.1 to 1.2 BCF. For the advanced technology case, the recoverable resources are estimated at 10 TCF. These estimates of recoverable resources are on a January 1, 1991 basis, while Tables 3-26 through 3-30 show resources on a January 1, 1986 basis.

Piceance Basin

Geologic Setting

The Piceance Basin, located in northwestern Colorado, contains large areas of productive coals in the Upper Cretaceous Mesa Verde group. These coals range in thickness from one to ninety feet and extend from surface outcrop to over 10,000 feet deep. Generally, gas contents vary from 300 to 600 SCF per ton in the most potentially productive areas.

Interbedded with the coals in many parts of the basin are several sequences of tight gas sands that are also known to be productive. In areas where the coals and tight sands are each marginally productive, they can and have been commingled in the same wellbore to enhance the economics of the wells. This is one of the factors that makes this basin attractive for exploitation of its coalbed methane resource.

Activity and Production

Coalbed methane development is still in its infancy in the Piceance Basin. Most of the coalbed methane wells have been completed in the last three years, with a marked increase in activity over the last 18 to 24 months. There are currently about 60 coalbed methane producing wells in the basin, with the deepest at about 8,000 feet.

Due to the short production history of the basin it is difficult to estimate expected ultimate recovery of the resource. Some wells exhibit a significant decline in production in the first year (30 to 60 percent), but then the decline levels off to about 3 to 6 percent per year. This may be the result of rapid depletion of the free gas in the cleats and fractures before true desorption of the coals begins. Other wells in the basin exhibit slight production increases within the first year or two and then begin to decline, as would be expected for a desorbing coal. In general, these wells do not produce the large amounts of water typical of San Juan and other basins.

Most coalbed methane wells were completed using conventional hydraulic fracturing technology. Some attempts have been made at open hole cavity completions, similar to those in the San Juan Basin, but they have not proven successful to date because the cavities never stabilize sufficiently to allow production. Although conventional fracturing appears to work well in some areas, an optimum completion technique for the coals must still be determined before widespread coalbed methane development can occur.

Traditionally, gas production from the Piceance Basin has been restricted due either to a lack of transportation or markets. There is reason for optimism, however, in the pipeline capacity situation. Three pipeline companies have announced plans that would increase transportation capacity from the basin by about 580 MMCF/D. Low gas prices during 1991 and early in 1992 reduced the economic viability of many coalbed methane wells. Price increases since mid-1992 have reversed that trend.

Development in some portions of the basin will be limited because of rugged terrain as well as unleasable National Forest Service lands or lands requiring detailed environmental impact statements.

Hydrocarbon Model Assumptions

The estimated coalbed methane resource for the Piceance Basin is 103 TCF in place. This compares to 84 TCF estimated by GRI in 1986. The current NPC figure is the result of a detailed mapping study by one of the operators using data from over 600 wells. The study determined that coal thickness and measured gas contents, from recent drilling results, were higher than previously estimated.

Resources recoverable with current technology are estimated at 17 TCF with as much as 27 TCF recoverable with advanced technology (January 1, 1991 basis). The basin was separated into nine cells for the model runs. Recovery per well ranges from 0.4 to 3.1 BCF and averages 1.5 BCF (current technology basis).

Raton Basin

Geologic Setting

The Raton Basin straddles the border between southeastern Colorado and northeastern New Mexico. The Upper Cretaceous Vermejo and Paleocene Raton formations contain the potentially productive coals within the basin. The coals have an average aggregate thickness of about 15 feet and range in depth from outcrop to 4,000 feet. Most of the coals originally were of low rank due to shallow burial depths. However, they later achieved bituminous rank from abnormally high temperatures and geothermal gradients induced by igneous intrusive activity associated with emplacement of the central Colorado mountain belt. Measured gas contents range from 30 to 510 SCF per ton.

Activity and Production

Over the last few years, activity has increased with several operators drilling a total of about 40 wells in the basin with modest production test results. The major factor limiting expansion of production is the lack of pipelines to transport the gas out of the basin. Even the existing wells are shut-in due to the lack of pipeline capacity. Colorado Interstate Gas, however, is planning to build a new pipeline into the basin to transport gas from these operators. It may still be some time before this basin makes a significant contribution to coalbed methane production because of the limited proved production capacity to date.

Hydrocarbon Model Assumptions

The Raton Basin was combined with miscellaneous Rockies basins for purposes of the model runs. The miscellaneous basins will be discussed separately below. The Raton Basin was estimated to contain 18 TCF in place with 5 TCF estimated recoverable resources with current technology. The miscellaneous Rockies basins (Uinta, Greater Green River, Powder River, Wind River) were estimated to contain 9 TCF in place, with an estimated 3 TCF recoverable. These basins were combined to simplify the model runs. The normally pressured areas of the San Juan Basin were used as an analog to provide expected recovery factors and other parameters for these basins. It is conceivable that, due to new technology enhancements or breakthroughs, one of these miscellaneous basins could become a large coalbed methane producer in the future.

Uinta Basin

Geologic Setting

The Uinta Basin is located in the northeastern corner of Utah. Potentially productive coals are found in several members of the Upper Cretaceous Mesa Verde group and the Ferron formation.

Conditions are good for coalbed methane production. The coals are moderately thick, continuous over large areas and gas contents range from 50 to 450 SCF per ton. Much of the coal occurs at drill depths of less than 3,000 feet.

Activity and Production

To date there has been only minor production of coalbed methane in the Uinta Basin. Currently, there are several operators in the process of testing coalbed methane potential in a number of areas. None of these tests are known to have shown commercial production rates to date although they are producing some gas.

Hydrocarbon Model Assumptions

Prior estimates of 3 to 5 TCF in place have been made for the Uinta Basin and appear to be reasonable based on gas content data obtained since then. However, lack of meaningful production makes it difficult to predict the potential recoverable resources. Therefore, this basin was rolled into the Rocky Mountain "miscellaneous" category for the model runs and assigned resources of 1 TCF with current technology and 1.6 TCF with advanced technology using a spacing of four wells per section.

Greater Green River Basin

Geologic Setting

The Greater Green River Basin is located in southwestern Wyoming and northwestern Colorado. It consists of several subbasins separated by the Rock Springs Uplift and other structural elements. Laterally persistent coals up to 20 feet thick are found within Upper Cretaceous and Lower Tertiary rocks. The coals are subbituminous to high volatile A bituminous in rank and occur from the surface to depths of more than 10,000 feet. Gas contents range from 0 to 540 SCF per ton with most of the coals containing less than 250 SCF per ton.

Activity and Production

Coalbed drilling activity began in the southeastern part of the basin (Sand Wash Basin) in 1989. Since that time, coalbed methane wells have been drilled in the eastern (Washakie and Great Divide Basins) and western portions of the basin. No commercial production has been established to date. Production, gas content and coal maturity data suggest that in general, the majority of the coals in this basin have not generated significant amounts of methane. Water production is high, probably enhanced by associated high permeability sands, especially in the Tertiary rocks. Initial estimates of 1 to 30 TCF gas in place have been substantially revised toward the lower end of the range.

Hydrocarbon Model Assumptions

For the purposes of the model runs, the Greater Green River Basin was grouped along with the other miscellaneous Rocky Mountain basins. It was assigned about 1 TCF of potentially recoverable resources utilizing 320 acre spacing with current technology. A multiplier of 1.6 was used for advanced technology.

Powder River/Wind River Basins

Geologic Setting

The Powder River Basin in southeastern Montana and northeastern Wyoming and the Wind River Basin in west central Wyoming both contain late Cretaceous to early Tertiary coals from a few feet to one hundred feet (Tertiary) thick. The coals extend from surface outcrop to 3,000 feet with some as deep as 6,000 feet. Gas content generally is less than 75 SCF per ton and coals range from lignite to subbituminous.

Activity and Production

There has been some small scale coalbed methane production from shallow (above 500 feet) wells on the eastern edge of the Powder River Basin but attempts to produce gas from deeper zones at 1,200 to 1,800 feet have been unsuccessful with large volumes of water and low gas volumes being produced. The Wind River Basin has yet to produce any commercial volumes of gas.

Hydrocarbon Model Assumptions

Although the Powder River Basin has an estimated 30 TCF of gas in place, most of it is contained in thick low-gas-content coals that have very limited producibility.

The Wind River Basin, due to its low rank coals, has only an estimated 2 TCF in place. Both of these basins were included in the Rocky Mountains "miscellaneous" basins category and are expected to contribute only about 1 TCF of recoverable resources combined, with current technology. A multiplier of 1.6 TCF was used for advanced technology. Most of this is expected to come from the Powder River Basin.

Northern Appalachian Basin

Geologic Setting

The Northern Appalachian Basin covers approximately 43,700 square miles of Ohio, Pennsylvania, West Virginia, Maryland, and Kentucky. Most of the major coal bearing formations of the basin occur in the Upper Pennsylvanian and Lower Permian Systems. These systems are divided into the Pottsville, Allegheny, Conemaugh, and Monogahela groups, and the Waynesburg formation.

Conditions in the basin are favorable for coalbed methane production. Both the Department of Energy and the Gas Research Institute estimate that there are approximately 61 TCF of gas in place in the seven major coal groups with a high-potential target area of 4,500 square miles located in southwestern Pennsylvania and northcentral West Virginia.

Activity and Production

The oldest coalbed methane field in the United States is located in Wetzel County, West Virginia, and has produced over two billion cubic feet of gas since 1949 from the Pittsburgh coal. Several tests were conducted by the DOE and the U.S. Bureau of Mines in the targeted area. A DOE project at Waynesburg College allowed for a coalbed well to be drilled in 1980 to 1,450 feet. The well was stimulated with a nitrogen-foam fracturing treatment and was producing 22 MCF/D with some water production after cleanup. Cumulative production to date is over 25 MMCF.

U.S. Bureau of Mines methane desorption tests for this basin show a range of 80 to 445 SCF per ton with an average of 150 SCF per ton for all coals. Known production in the Northern Appalachian Basin is comparable to that of economic wells in the Black Warrior Basin.

Hydrocarbon Model Assumptions

For modeling purposes, the Northern Appalachian Basin was divided into three cells of varying depths (1,000 to 2,000 feet) and areas (500 to 5,000 square miles) totaling 7,800 square miles. Total gas in place was estimated to be 30 TCF with 9 TCF recoverable with current technology and 15 TCF recoverable with advanced technology. Recovery per well under the base case ranged from 150 MMCF to 300 MMCF, and under the advanced technology case, 240 to 480 MMCF.

Basins Not Included in Hydrocarbon Model

The following group of basins includes those previously assigned significant potential or those added for analysis in this study. These basins were not included in the model runs due to their low potential or lack of meaningful data.

Cherokee and Forrest City Basins

Geologic Setting

The Cherokee and Forrest City Basins are located in eastern Kansas and western Missouri. Productive coals are found in the Cherokee Group of Pennsylvanian age. The coals are generally thin, a few inches to six feet thick, with gas contents averaging about 200 SCF per ton. Depths range from surface to about 1,200 feet.

Activity and Production

Currently the vast majority of production comes from southeastern Kansas in the Cherokee Basin around Independence. Wells are commonly 800 to 1,000 feet deep and produce 40 to 100 MCF/D from one or two coal seams of four to six foot thickness. Salt water is produced with the gas at 10 to 100 barrels per day, and is injected into the deeper Cambro-Ordovician Arbuckle zone at about 1,500 feet. Producing wells cost $30,000 to $40,000 to drill and complete, while water disposal wells run about $20,000 and can handle the water from 15 to 20 producing wells.

To date only a few test wells have been drilled in the Forrest City Basin. Available information indicates that the gas contents and seam thicknesses are similar to the Cherokee Basin and production is expected to behave in about the same way. The Kansas Geological Survey recently announced plans to drill a new test well near Leavenworth to gather more coalbed methane information in the basin. It is also known that the coals in the Forrest City Basin thicken eastward into Missouri, which may bode well for future production potential.

Using information provided by the Kansas Geological Survey, the NPC estimated that the total gas in place for both basins is about 2 to 3 TCF with 0.9 to 1 TCF potentially recoverable. The average well should recover 200 to 300 MMCF.

Central Appalachian Basin

Geologic Setting

The Central Appalachian Basin covers approximately 23,000 square miles over parts of southwestern Virginia, southern West Virginia, eastern Kentucky, western Maryland, and eastern Tennessee. The Kentucky River Fault system and the Rome Trough Hinge Line separate the Northern and Central Appalachian Basins. Coals in the basin are as deep as 2,500 feet and range in rank from high to low volatile bituminous.

Productive coals occur in the Mississippian and Pennsylvanian Lee and Pottsville formations. The primary target area covers about 4,000 square miles in southwest Virginia, southeastern

West Virginia, and parts of eastern Kentucky. The Pocahontas coals have the highest average gas content of any of the measured coals within the basin, with some samples containing over 650 SCF per ton of methane.

Activity and Production

The Central Appalachian Basin has some of the highest methane desorption values in the United States. Estimates of gas in place range from GRI's 5 TCF to DOE's 10 to 48 TCF. Current production is dominated by on-site power generation at coal mines as a consequence of degassing the coals before they are mined. However, production activity is moving away from the coal mines as a result of the impetus provided by the Section 29 tax credit. Activity is currently higher here than in the Northern Appalachian Basin, particularly in southwestern Virginia.

Gas in place was estimated by the NPC at 5 TCF, with 2 TCF recoverable under current technology.

Western Washington

Geologic Setting

The coalbeds of western Washington are located in the Eocene sediments of the Puget Downwarp, an elongate north–south string of basins lying predominantly along the west flank of the volcanic Cascade Range. A portion of the basin is also exposed on the east side of the range in central Washington. Coals are present from the surface to over 10,000 feet and are generally bituminous but range from subbituminous to anthracitic. The coals are a few inches to forty five feet thick with gas contents of 75 to over 500 SCF per ton.

Activity and Production

To date only seven or eight coalbed methane wells have been drilled in Washington with no commercial production established and only minimal testing conducted. Previous estimates of up to 24 TCF of gas in place may be reasonable, but estimates of recoverable reserves are very questionable since much of the gas resides in the thicker lower grade coals.

No production or reserves were assigned to Washington in the model runs. However, this basin may have potential to become a large producer in the future.

Illinois Basin

Geologic Setting

The Illinois Basin occupies most of Illinois, and parts of southwestern Indiana and northwestern Kentucky. The coals are Pennsylvanian in age and range up to 15 feet thick. The coals are found from the surface to 1500 feet deep with gas contents of 32 to 149 SCF per ton.

Activity and Production

This basin was previously estimated to contain 5 to 21 TCF in place, which may be quite reasonable. However, the very low gas content of the coals and poor results from a few wells drilled indicate that it is unlikely that commercial production will be established without some major technological breakthrough. Therefore, this basin was not included in the model or considered to be an area with future potential.

Other Basins

A number of other basins, including the Arkoma, Cahaba, Coosa, Richmond, Pennsylvanian anthracite and Texas lignites, were reviewed as part of the overall assessment and were found not to have significant coalbed methane potential based upon present knowledge. A few of these basins (Arkoma, Cahaba, Coosa) currently have some minor drilling activity sparked by the Section 29 tax credit, but none is expected to be a significant producer of coalbed methane.

Cell Descriptions

Descriptions of the coalbed methane cells developed for the Enhanced Recovery Module of the Hydrocarbon Model are shown in Tables 3-26 through 3-30. Ten cells are used to describe the Fruitland coal and seven major cells to describe the Menefee coal of the San Juan Basin; nine to describe the Piceance coals; ten for the Raton Basin and miscellaneous Rockies; thirteen for the Black Warrior Basin Coals; and three for the Northern Appalachian Basin coals. The recoverable resources in the table are on a January 1, 1986 basis, which is used for model input. As a result, they differ for some regions

TABLE 3-31

ESTIMATED COALBED METHANE RESERVE ADDITIONS AND PRODUCTION
(Trillion Cubic Feet per Year)

	1990	1995	2000	2005	2010
Reserve Additions					
NPC Reference Case 1					
Coalbed Methane	2.1	1.6	1.0	1.1	2.1
Total Gas	18.5	15.1	18.7	22.2	22.5
NPC Reference Case 2					
Coalbed Methane	2.1	1.5	0.6	0.7	1.1
Total Gas	18.5	11.8	15.5	17.9	18.3
Production					
NPC Reference Case 1					
Coalbed Methane	0.2	0.8	1.1	1.2	1.3
Total Gas	17.3	17.8	18.3	20.0	20.5
NPC Reference Case 2					
Coalbed Methane	0.2	0.8	1.0	0.9	0.9
Total Gas	17.3	17.1	16.0	17.4	17.4

from those shown in Table 3-25, which are on a January 1, 1991 basis.

Model Results

In 1990, coalbed methane reserve additions were about 2 TCF or 11 percent of total gas reserve additions, as shown in Table 3-31. In 1991, coalbed methane reserve additions were 3 TCF. In NPC Reference Case 1, additions are projected to decline through 2000, to about 1.0 TCF, after the Section 29 tax credit expires. After 2000, reserve additions are projected to again increase, and are estimated to reach 2.1 TCF in 2010. A similar pattern is projected in NPC Reference Case 2, with additions declining to 0.6 TCF in 2000 and increasing to 1.1 TCF by 2010.

Production of coalbed methane was about 0.2 TCF in 1990 but increased in 1991 to 0.3 TCF and is projected to reach about 0.4 TCF in 1992. In Case 1, production is estimated to increase to 1.1 TCF in 2000 and 1.3 TCF in 2010. In Case 2, production of coalbed methane increases to about 1.0 in 2000, and then remains about flat.

Even though it is assumed that the tax credit will be allowed to expire at the end of 1992, increased efficiency and improved technology are expected to keep coalbed methane production competitive with conventional gas resources over the time frame considered in this study, and this is confirmed by the results of the Hydrocarbon Supply Model.

Model Runs Through 2030

For model runs through 2030, a "second generation" of advanced technology was added to recoverable resources, as shown in Table 3-32.

TABLE 3-32

RECOVERABLE RESOURCES
JANUARY 1, 1991 BASIS
(Trillion Cubic Feet)

	Current Technology	1990 to 2010 Advanced Technology	Second Generation Advanced Technology
Coalbed Methane	62	98	125

Results of the model runs showed production of coalbed methane declining after 2010 in the run at $1.50 per million BTU in 1990 dollars, but increasing in the $2.50, $3.50, and $4.50 runs (Table 3-33).

TABLE 3-33

PRODUCTION OF COALBED METHANE (Trillion Cubic Feet)

Run*	2000	2010	2030
$1.50	0.34	0.90	0.12
$2.50	1.03	0.88	1.73
$3.50	1.07	1.18	2.23
$4.50	1.07	1.26	2.59

* Maximum Gulf Coast wellhead price of gas in 1990$ per million BTU. In some runs, prices are well below the maximum up to 2010. The runs are discussed in greater detail in Chapter Two.

Sources for Coalbed Methane Section

National Petroleum Council, *Unconventional Gas Sources, Volume II – Coal Seams*, June 1980.

Potential Supply of Natural Gas in the United States (December 31, 1988); report of the Potential Gas Committee. Richard J. Burgess, President/General Chairman; Potential Gas Agency, Colorado School of Mines, April 1989.

Enron Corp., *Outlook for Natural Gas, Fueling the Future into the 21st Century*, 1991.

W. Fisher, et al, *An Assessment of the Natural Gas Resource Base of the United States.* U.S. Department of Energy, Office of Planning and Analysis, DOE/W/31109-141, 1988.

Gas Research Institute, *Quarterly Review of Methane from Coal Seams Technology*, October 1989.

SPECULATIVE GAS SOURCES

Summary

Natural gas originating in deep sediments, gas trapped in naturally occurring mixtures of methane in ice, called hydrates, and gas from geopressured aquifers have been identified as "speculative" gas sources. The volumes of gas that are believed to be contained in these three potential future sources are very large (11,600 TCF), dwarfing any reasonable estimate of gas remaining in conventional sources. However, the cost of recovering gas from these sources remains uncertain.

The thrust of required research in connection with the recovery of these sources is twofold: (1) to better quantify estimates of the gas actually present in each source and (2) to develop techniques for extracting the gas at acceptable cost. These sources are viewed as long-range research and development efforts with potential payoff beyond 2010.

Deep Gas Deposits

Deep gas deposits are similar to tight sand gas deposits in that porosity and permeability are reduced in deeply buried sediments. Many sedimentary basins in the United States reach maximum depths of 30,000 to 45,000 feet and, despite high temperatures at these depths, methane is still in a stable phase—provided carbon in the form of graphite or kerogen is present in the host rock. Although the United States has many more wells and a much higher density of drilling than any country in the world, only a small fraction of deep sediments has been explored. Even so, very large gas resources have already been identified at depths in the 14,000 to 22,000 feet range. Speculative deep gas estimates in the United States show nearly 3,200 TCF of methane.[5]

The deep Anadarko Basin in Oklahoma may contain over 75 TCF of methane. The success ratio for exploration in the Anadarko Basin is more than triple the U.S. average, with two out of every three wildcats finding natural gas. The Eastern Gulf Coast and Louisiana Offshore region may contain over 40 TCF of gas; more than 200 TCF may be in place in the Rocky Mountain Overthrust Belt.

In 1990 there were 289 deep wells (>15,000 feet) drilled in eleven states with 68 of these deep wells in Louisiana. Industry spent

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[5] January 1988 United States Geological Survey (USGS) deep gas estimate.

more than $1.6 billion to drill and complete these wells with an average total depth of 16,737 feet and an average cost per foot of $347 with average cost per well of $5.8 million. Offshore deep wells in 1990 cost more than $11 million apiece while onshore deep wells came in at just under $4 million.[6]

The existence of gas in ultra-deep (> 25,000 feet) sources depends on the presence of organic material in the deeply buried sediments. The future of ultra-deep gas as a resource will depend on finding reservoir rocks with adequate porosity and permeability to allow rates of production that are high enough to insure a reasonable economic return. Because drilling costs have historically scaled roughly as the square of well depth, new technology will be required to reduce costs.[7]

Gas from Geopressured Aquifers

One of the most abundant of the speculative deposits of gas in the U.S. is aquifers. Such aquifers exist in Oklahoma and in other western states, but principal interest has focused on the Gulf Coast states of Texas and Louisiana. Under pressurized conditions, brines at depths of 8,000 to 9,000 feet contain 20 to 40 standard cubic feet of gas per barrel of brine. The in-place resource estimates are enormous. The U.S. Geological Survey has estimated 5,700 TCF of methane in deep aquifers.

Technologies for developing these resources are economically marginal. A principal problem is the need for an environmentally satisfactory method of brine disposal. Ideally, the gas could be separated from the brine at the surface, and the heat contained in the brine could be used to generate electricity. Although the production base is very large, the low energy density of the brines and the environmental problems connected with brine disposal will delay the near-term use of this resource.[8]

Geopressured aquifers have been the focus of major test programs in the United States. Deep geopressured well tests in the Gulf Coast region of the United States have been sponsored jointly by the government and industry with preliminary results of this testing program available. The Department of Energy/Institute of Gas Technology Pleasant Bayou test well on the Texas coast is currently producing about 23,000 barrels per day of brine at 294 degrees Fahrenheit, and produces over 500 MCF/D of gas.

Gas from Mining Operations

Coalbed gas or "firedamp" has long been the nemesis of the underground coal miner. It is present in all coalbeds to a greater or lesser degree, and typically contains between 80 and 99 percent methane. Removal of this gas from mines requires dilution with large volumes of ventilation air. High volumes of released methane from fractured overlying coals accompany longwall mining methods.

Longwall mining was first introduced in the United States in the early 1970s. Over 95 longwall systems are found in U.S. coal basins with nearly 75 percent of these in the Appalachian Basin alone.[9] Longwall mining technology greatly impacts the subsurface strata by leaving behind unsupported roof strata that fracture and collapse into the space created by the coal removal process.

The caving process liberates gas in overlying coalbeds and gas bearing strata. To prevent the methane gas from entering the active mine, 2 to 5 vertical wells (gob vent wells) are drilled into or near the top of the coalbed prior to mining. Methane gas begins to flow once the longwall shear has advanced past the vent wells. The amount of methane emitted from these vertical vent wells may range from several hundred thousand cubic feet per day to several million cubic feet per day.

At least three coal mining companies are presently selling methane gas from mining operations for pipeline use in the United States. Two of these operations are in the Black Warrior Coal Basin in Alabama—Jim Walter Resources and USX. These companies are currently producing over 65 MMCF/D.[10] In the Uinta (Utah) Basin, the Soldier Canyon mine is selling methane from in-mine horizontal boreholes at a rate of 1 MMCF/D. All of the gas produced from these mine vent wells is pipeline quality; a total of 24 BCF was produced in 1990.

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[6] Petroleum Engineer International, March 1991, pp. 14-20.

[7] Annual Review of Energy, 1990, 15:53-83.

[8] Ibid.

[9] Longwell Census '90, Coal, February 1991.

[10] Gas Research Institute, Methane from Coal Seams Technology, July 1991.

Since 1986 Jim Walter Resources alone has produced over 75 BCF of methane.

The magnitude of methane gob emissions not being produced for sale from longwall mining operations has been estimated from 50 to 65 BCF per year.[11] This is a very conservative estimate since no regulation exists to monitor the amount of methane vented from vertical pre-mining wells, post-mining gob-vent wells, and in-mine horizontal wells. Only U.S. Bureau of Mines and Mine Safety and Health Administration data on methane vented from mine ventilation air exists publicly. The 1988 total for vented methane from 487 mine ventilation systems was 295 MMCF/D.[12]

Hydrate Resource Potential and Production Economics

In 1964, the U.S.S.R. announced a natural source of gas hydrates that could supply worldwide energy demands for centuries, according to their estimates of resource in place. Gas hydrates are physical combinations of gas and water in which the gas molecules fit into a crystalline structure similar to that of ice. A 90 percent gas-saturated hydrate contains 167 standard cubic feet of gas per cubic foot of hydrate.

A general range of the potential volume of gas in place has been estimated for eight study areas surrounding North America, using a standardized procedure. An aggregate estimate for all study regions was developed and extended to produce an estimate for world abundance of natural gas in hydrate form. Each section of the regions was divided into areas of hydrocarbon generation potential. The volume of hydrate in a 3.28 foot thick interval of 50 percent porosity sediment with 50 percent of the pore space occupied by hydrates was calculated for each area. The unit volume was multiplied by an estimated lateral extent of the hydrate. The lateral extent assigned varied from 0 to 80 percent for different parts of study regions. The estimated lateral extent of hydrates was based principally on the quantity of evidence of hydrate presence that was available for each area. A grid of closely spaced seismic lines with drilling corroboration permitted a very confident estimate of hydrate lateral extent. Large regions with no data of either a positive or negative nature were assigned very low lateral-extent factors.

Estimated Potential

The potential gas resource values obtained for each study region are listed in Table 3-34. Depending on the thickness assigned to the hydrate zone causing the Bottom Simulating Reflector, the estimated gas-in-place figure for the regions studied ranges from 485 TCF for a 3.28 foot thick zone to about 3,100 TCF for a 32.8 foot thick zone. The figure derived for a 32.8 foot zone of hydrate is less than 10 times the estimate for a 3.28 foot thick zone. This is because the thickness of the zone typically refers to the layer of hydrated sediment that causes the Bottom Simulating Reflector. Some areas (e.g., Beaufort Sea) have independent estimates of vertical distribution of hydrates derived from drilling data.

The regions studied constitute about 10 percent of the continental margins of the world. The studied regions may be the most prospective in the world, because selection of the regions by the DOE was based on prior information that hydrates exist in those regions. Alternatively, hydrates may occur evenly throughout continental margins of the world.

TABLE 3-34

ESTIMATED POTENTIAL GAS RESOURCES IN GAS HYDRATES (Trillion Cubic Feet)

Study Region	3.28 foot Hydrate Zone	32.8 foot Hydrate Zone
Offshore Labrador	25	250
Baltimore Canyon	38	380
Blake Outer Ridge*	66	660
Gulf of Mexico	90	900
Northern California	5	50
Aleutian Trench	10	100
Beaufort Sea	240	725
Prudhoe Bay/Kuparuk	11	44
Total	**485**	**3,109**

* Offshore Carolinas and Georgia.

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[11] U.S. Department of Energy estimate, 1991.

[12] U.S. Bureau of Mines, "Evaluation of U.S. Coal Mine Emissions," Proceedings of the 5th Mine Ventilation Symposium, 1991, Morgantown, West Virginia.

The regions studied may have more documented evidence of hydrate presence solely because they have been subjected to more extensive drilling and seismic exploration. Extending the conservative figures listed in the table to the rest of the margins of the world suggests that gas hydrates may contain 7,000 to 50,000 TCF of natural gas. More drilling data on the nature of the hydrate occurrence that causes Bottom Simulating Reflectors could increase these estimates by a factor of 10.

In terms of energy content, gas hydrates are more comparable with heavy oil and tar sands than with nonconventional gas. Nonconventional gas sources contain from 1 to 12 cubic feet of gas (1,000 to 12,000 BTU) per cubic foot of reservoir, while gas hydrates typically contain about 50 cubic feet of gas (50,000 BTU) per cubic foot. In comparison, conventional gas reservoirs contain from 10 to 20 cubic feet of gas per cubic foot. A heavy oil reservoir can contain about 150, 000 BTU (150 cubic feet gas equivalent) per cubic foot of reservoir. After adjusting for a recovery efficiency of 30 to 40 percent, the recoverable energy of 45,000 to 60,000 BTU per cubic foot of heavy oil reservoir is similar to that of gas hydrates.

Estimated Hydrate Production Economics

While there is very little data on the economics of producing gas from hydrate deposits, some documentation exists on estimates derived from "back of the envelope" type calculations and production scenarios (i.e., thermal injection, depressurization, etc.). In a 1990 document, *Annual Review of Energy* (15:53-83, Annual Reviews, Inc.), is an article "The Future of Methane as an Energy Resource," by Gordon MacDonald of the MITRE Corporation, in which he discusses the economics of gas production from hydrate deposits. Table 3-35, developed by MacDonald, lists the computed costs for production from a 25 foot thick gas hydrate zone that has a porosity of 40 percent, a permeability of 600 millidarcies, and is located on the North Slope of Alaska. The recovery rate is determined by an injection rate of 30,000 barrels per day of water at 150 degrees Centigrade. Costs for transportation involve transport first by pipeline from the North Slope to Cook Inlet, and then by liquefied natural gas tanker to markets in Japan and the Pacific West Coast. The total cost, including the transportation cost, of about $7.00 to $9.00 per MCF, is about equal to the cost of gas produced from other speculative sources. The cost of production by depressurization alone is estimated at roughly $3.00 per MCF.

TABLE 3-35

ESTIMATED COMPARISONS OF HYDRATE GAS PRODUCTION — ALASKA
(1988$ Per Thousand Cubic Feet)

	Thermal Injection	Pressure Reduction
Transportation Cost	4.25	4.25
Break-Even Price Including Royalties and Fees	8.75	7.10

Another article in the 1988 edition of the same document, *Annual Review of Energy* by M. H. Nederlof of Shell International Petroleum of the Hague, Netherlands, has a graphic for economics of nonconventional gas production, including gas hydrates. This graphic has been included as Figure 3-3. According to Nederlof, gas hydrate production costs currently fall between $5.00 and $15.00 per MCF from onshore deposits. Nederlof's calculations apparently do not consider transportation costs.

Research and Policy Recommendations for Speculative Gas Sources

Technology development for recovery of gas from speculative gas sources is at a very early stage, and much work needs to be done. Although in-place resources are very large, little is known about recovery techniques and economics. Deep gas deposits and geopressured aquifers are likely to be more costly to develop than gas hydrates, despite their apparently huge resources in place.

Federal and state policy should encourage technology development, including allowing access to areas of known resources for research and development. More geological and geophysical work should be encouraged to better determine the extent and location of the resources.

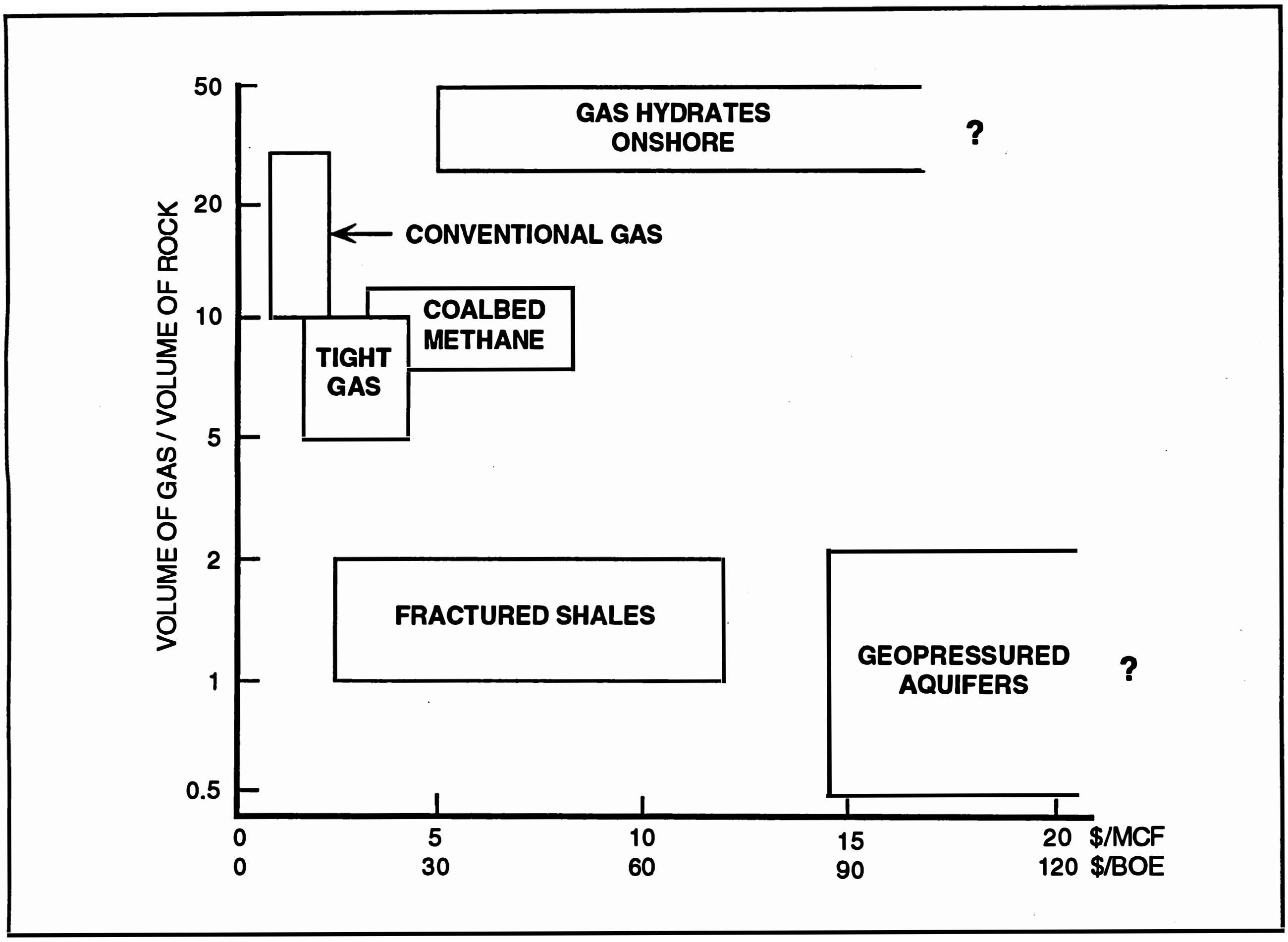

Figure 3-3. Comparison of Nonconventional Gas Production Economics.

CHAPTER FOUR

IMPORTS AND ALASKA

SUMMARY

The importation of pipeline gas and liquefied natural gas (LNG) will significantly impact the sustainability and reliability of supply in the United States. A clear understanding of the resource base and potential productivity identified in Canada, Mexico, Alaska, and the LNG supplying countries is essential to determine the availability of future import and export volumes and the transportation requirements for moving these volumes to market. Incremental market demand and fundamental supply/demand economics will drive ultimate deliveries.

History

The United States is the largest net importer of natural gas in North America. In the lower-48 states, net natural gas imports increased 73 percent in 1991 over the 1980 level (1,699 vs. 981 billion cubic feet [BCF]), a 718 BCF change. Imports have consistently risen since the mid-1980s when the average price of imported pipeline gas dropped below $2.00 per thousand cubic feet (MCF). Net imported natural gas accounted for 9.0 percent of the natural gas end-use demand in the United States in 1990 and 9.8 percent in 1991. The importation of natural gas and its contribution to gas consumed will continue to increase to meet the growing demand for marginal requirements of natural gas supply well into the next century (Tables 4-1, 4-2, and 4-3).

Import volumes during the past decade have been the most significant from Canada. Although relatively stable and consistent in the early 1980s, deliveries have more than doubled since 1980 to 1,695 BCF per year in 1991. Gas imports from Mexico began anew in 1980, after a short period of interruption, to again cease at the end of 1984. LNG imports have had a variable history of delivery volumes. Deliveries of LNG in 1990 (84 BCF) and 1991 (64 BCF) were the largest in the past 10 years, with the exception of 1983 when 131 BCF was received.

Exports from the United States to Canada have been minimal, approximately 17 BCF per year for 1990 and 1991. Exports to Canada have resulted from transportation and exchange agreements between pipelines and customers in close proximity to the border. Gas exported to Mexico, however, has increased from 16 BCF per year in 1990 to 60 BCF per year in 1991 due to increased utilization along the border. LNG exports from Alaska have ranged from 44 to 56 BCF per year since 1970.

Resource Overview

The proved and potential natural gas resources in North America are substantial (Table 4-4). Canada has an abundant resource base of natural gas and enormous potential in both the Western Canada Sedimentary Basin and in northern frontier areas. Proved reserves in the Western Canada Sedimentary Basin are 71 trillion cubic feet (TCF). Conventional resources are estimated to be 522 TCF with 317 TCF located in frontier areas. Nonconventional resources are estimated to be 218 TCF,

TABLE 4-1

U.S. LOWER-48 NET NATURAL GAS IMPORTS*
(Billion Cubic Feet per Year)

Year	Canada	Mexico	Alaska	LNG	Total Net Imports	% of End-Use Demand†
1980	797	98	0	86	981	5.4
1981	762	102	0	37	901	5.1
1982	783	93	0	55	931	5.8
1983	712	73	0	131	916	6.0
1984	755	50	0	36	841	5.2
1985	926	-2	0	24	948	6.1
1986	740	-2	0	2	740	5.0
1987	990	-2	0	0	988	6.4
1988	1,256	-2	0	17	1,271	7.9
1989	1,301	-17	0	42	1,326	7.8
1990	1,431	-16	0	84	1,499	9.0
1991	1,695	-60	0	64	1,699	9.8

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* EIA — *Natural Gas Monthly*, August 1991. Net imports equal natural gas imports brought into the lower-48 states for sale, minus those gas volumes exported for sale to other countries—it does not include transportation and exchange volumes.

† EIA — *Monthly Energy Review*, July 1992; total deliveries to consumers (excludes lease and plant fuel, and pipeline fuel).

TABLE 4-2

U.S. LOWER-48 NET NATURAL GAS IMPORTS MODERATE ENERGY GROWTH SCENARIO
(Quadrillion BTU per Year)

Year	Canada	Mexico	Alaska	LNG	Total Net Imports	% of End-Use Demand
1992	1.798	-.113	0	.086	1.771	9.8
1995	2.354	-.258	0	.131	2.227	11.9
2000	2.524	-.340	0	.273	2.457	12.6
2005	2.713	-.185	0	.272	2.800	13.2
2010	3.230	.103	0	.270	3.603	15.9

TABLE 4-3

U.S. LOWER-48 NET NATURAL GAS IMPORTS LOW ENERGY GROWTH SCENARIO
(Quadrillion BTU per Year)

Year	Canada	Mexico	Alaska	LNG	Total Net Imports	% of End-Use Demand
1992	1.797	-.113	0	.086	1.770	9.8
1995	2.379	-.258	0	.099	2.220	12.3
2000	2.467	-.340	0	.246	2.373	13.6
2005	2.517	-.433	0	.273	2.357	12.7
2010	2.794	-.515	0	.273	2.552	13.6

TABLE 4-4

NORTH AMERICAN NATURAL GAS RESOURCES AS OF DECEMBER 31, 1990
(Trillion Cubic Feet)

	Canada	Mexico	Alaska	Total	U.S. Lower-48
Proved	72	72	9	153	160
Conventional	450	180	114	744	616
Nonconventional	218	–	57	275	519
Total	**740**	**252**	**180**	**1,172**	**1,295**

Basis — Technically recoverable resources incorporating technology advancement through 2010, except for Mexico.

although estimates by some experts range as high as 3,000 TCF. Little effort has been dedicated to the evaluation of this resource.

Mexican proved natural gas reserves are also substantial, but essentially they are all associated with oil reserves. Proved reserves are estimated at 71.5 TCF, roughly 40 percent of that of the U.S. lower-48. Industry estimates of Mexico's undiscovered potential are 180 TCF. The full potential of non-associated gas resources, conventional and nonconventional, will not be defined until gas exploration and development are given higher priority.

Alaskan natural gas resources are abundant, but, due to lack of commercial opportunities, only 9 TCF is designated as proved. With an estimated 114 TCF of recoverable conventional gas resources and over 57 TCF of unconventional gas resources, the potential exists for significant additional gas resources to be discovered. However, development of Alaskan gas to meet marginal demand requirements in the lower-48 states will be a function of delivered prices and is not expected before year 2010.

Due to location and shipping distances, the most likely sources of additional LNG for the U.S. market will be from countries in the Atlantic and Caribbean regions. Currently, Algeria is the only supplier of LNG to the United States, and production capacity available to the U.S. will continue to be limited to 200-350 million cubic feet per day (MMCF/D) until Algeria's revamping program is completed in 1996. By the late 1990s, with the completion of this revamping program and the projected start-up of LNG supply projects in Nigeria and Venezuela, total available production for export to the United States may be as high as 1,260 MMCF/D.

Supply Outlook

Canada, Mexico, and Alaska must meet their internal demand for natural gas before volumes in excess of these requirements may be considered as available to the lower-48 states. The United States cannot assume that the entire North American resource base (2,500 TCF) is destined to satisfy lower-48 natural gas demand. Internal demand is relatively small for the LNG-supplying countries. Instead, the U.S. lower-48 market must compete with the higher-priced European markets for this supply.

Canada

The natural gas resources in Canada provide the most immediate source of gas to augment U.S. supply. The discovery of natural gas in Canada dates back to 1880, but large scale development did not occur until after the discovery of the Leduc oil field in Alberta in 1947. Since then, natural gas has been developed along the same lines as in the lower-48 states. Between 1958 and 1982, pipelines were completed linking western Canadian supplies to markets in California and the Midwest. These developments, along with new pipeline expansions to serve the Northeast U.S., have essentially integrated Canadian and U.S. lower-48 states' natural gas supplies into a consolidated North American natural gas market.

In 1991, net imports from Canada totaled 1.746 quadrillion BTU (QBTU) (1,695 BCF), a 16 percent increase over the 1990 level. Assuming moderate energy growth in the United States (NPC Reference Case 1), net imports from Canada are expected to increase to 2.524 QBTU by 2000 and 3.230 QBTU by 2010. Under the low energy growth scenario (NPC Reference Case 2), net import volumes will increase more slowly, to only 2.467 QBTU in 2000 and 2.794 QBTU in 2010.

The price of Canadian gas (1990$) at the Alberta/Saskatchewan border (Empress) also increases under Reference Case 1, from $1.06 per million BTU (MMBTU) in 1991 to $2.46/MMBTU in 2000 and $2.79/MMBTU in 2010. The rise in the Empress price has significance for most of Canada's gas exports as it is the major receipt point for the TransCanada Pipeline, which feeds all export points to the U.S. lower-48 except those on the West Coast. During the same period, U.S. Gulf Coast spot gas prices increase from $1.27/MMBTU in 1991 to $2.88/MMBTU in 2000 and to $3.47/MMBTU in 2010. The reduced import volumes in the low growth scenario are reflected in a more gradual price escalation. The average price at the Empress receipt point increases to only $2.18/MMBTU by 2010, while Gulf Coast spot gas prices increase to $2.74/MMBTU.

Canadian domestic demand increases at a slower pace than in the United States, rising only 32 percent to 2.694 QBTU by 2010 in the moderate energy growth scenario. Demand is essentially flat in the low energy growth scenario, increasing only 6 percent to 2.168 QBTU by 2010. The National Energy Board of Canada projects some limited growth in residential and commercial markets, while growth in the industrial sector will be partly offset by improvements in energy efficiency and a shift away from energy-intensive industries. Gas used for electricity generation remains insignificant since this market is dominated by coal, nuclear, and hydro-power. Exports from the United States to Canada are assumed to be flat at 38 TCF per year (more than twice the 1990 and 1991 actuals) through 2010.

Mexico

The Mexican natural gas industry is essentially an associated by-product of the nation's oil industry. Due to this lack of focus on gas, Mexico's natural gas industry must be considered in its infancy relative to the United States or Canada. Current wet gas production is slightly over 1.3 TCF, down from a high of 1.5 TCF in the early 1980s. The Mexican pipeline infrastructure currently operates essentially at capacity. Pipeline capacity between the United States and Mexico is approximately 320 BCF per year, including Valero Transmission Company's recent expansion at McAllen, Texas. Several other expansion projects are also being discussed. This capacity can be used for either exports or imports.

Natural gas is currently receiving a renewed emphasis within Mexico's energy mix. Due to its environmental advantages, gas is replacing high sulfur fuel oil in both industrial and power generation applications. Petroleos Mexicanos (PEMEX), Mexico's state run oil company, has adopted a strategy to selectively source the heavily polluted Mexico City area with indigenous gas supply. The large industrial centers in the north near Monterrey have increasingly been forced to turn to the United States for gas.

Natural gas trade between the United States and Mexico has existed for over 40 years; however, the volumes have typically been minor. Between 1980 and 1984, Mexico exported an average of 86 BCF per year to the United States under a contract between PEMEX and a consortium of U.S. pipelines. These exports were suspended in November 1984. Exports from the United States to Mexico, however, continue to expand, growing from 1 to 2 BCF per year in the mid-1980s to 60 BCF in 1991. The recent rise is due to PEMEX's inability to keep pace with the country's growing demand for natural gas.

In the near to medium term, Mexico will represent an incremental market for U.S. gas. A severe lack of development capital will likely keep the country dependent on U.S. imports through the 1990s. Spurred by strong growth in both industrial and electricity demand, annual imports into northern Mexico are projected to increase from 60 BCF in 1991 to as much as 330 BCF (900 MMCF/D) by the turn of the century.

In the long term, Mexico has the potential to become a major supplier to the United States, because its immense reserves are in close proximity and their pipelines are already linked to the United States. The key to developing Mexico's gas potential and changing the country's position from being a net importer to that of a net exporter is the availability of capital for both gas development and expansion of the existing pipeline infrastructure.

Alaska

Historical Alaskan hydrocarbon activity has focused more on oil than natural gas. However, in addition to large quantities of oil, Alaska has significant gas resources. Over 25 TCF of recoverable gas is known to exist in the Prudhoe Bay field alone. Other Alaskan North Slope structures also contain significant amounts of gas. The issue for Alaskan gas is not one of resource availability, but one of market access. Demand for natural gas in Alaska is small compared to its gas supply. However, Alaska is extremely remote from other gas markets. Bringing large quantities of additional Alaskan gas to market requires large-scale projects that are very expensive, have long lead times, and involve complex commercial issues.

Alaskan natural gas demand is currently about 400 BCF annually. Slightly more than half of this gas is used for oil production activities on the North Slope of Alaska, with LNG exports, chemicals production, and power generation representing most of the remaining gas demand. Alaska has a proved reserves-to-production ratio of 20 years, compared to less than 10 years in the lower-48 states. Again, the issue is not lack of supply, but lack of access to market.

Two major projects have been proposed for bringing additional quantities of Alaskan gas to market. The Alaska Natural Gas Transportation System would move natural gas to the lower-48 states via pipeline through Canada. The Trans-Alaska Gas System would transport North Slope gas to southern Alaska, liquefy the gas, and move it to Pacific Rim markets as LNG. Neither project is under construction at this time and significant contractual and economic issues must be resolved before either project could proceed.

The gas supply and demand balance projected in both NPC Reference Cases indicates that the lower-48 states' gas requirements can be adequately met through at least the year 2010 from sources other than Alaska. Other sources, particularly Canadian gas and lower-48 indigenous supplies, can more economically supply U.S. gas demand. Therefore, although Alaska will continue to have large quantities of known natural gas resources, Alaskan gas will not materially impact other North American markets through the study period.

Liquefied Natural Gas

Although only a small fraction (2.4 percent in 1991) of the world's liquefied natural gas supply is currently imported by the United States, over the next 20 years LNG will provide a supplemental source of natural gas for peak shaving and to replace higher cost energy alternatives, e.g., propane or synthetic natural gas.

The United States has four LNG receiving terminals with a total capacity of 2.19 billion cubic feet per day. Currently, only the Everett, Massachusetts, and Lake Charles, Louisiana, facilities are operational; the Cove Point, Maryland, and Elba Island, Georgia, terminals have been idle since 1980.

In the near term, import volumes will remain relatively small (100-200 MMCF/D), reflecting the intense competition with the higher priced European markets for limited Algerian supplies. In the longer term, with the completion of Algeria's revamping program in 1996 and the projected start-up of new projects in Nigeria and Venezuela by the late 1990s, additional production capacity will be available to the United States. A summary of potential LNG supply to the United States is shown in Table 4-5.

TABLE 4-5

POTENTIAL U.S. LNG SUPPLY

Supplier	Volume (MMCF/D)	Date Available
Algeria	218	1992
Algeria (after revamping)*	512	1996
Nigeria	70	1997
Venezuela	560	1998

*Algerian liquefaction facilities are currently able to operate at only 70 percent of capacity; a massive revamping program is underway to return the facilities to 100 percent of nameplate capacity.

Under each of the reference case scenarios, LNG imports are projected to increase from 64 BCF in 1991 to 253 BCF in 2010. The Cove Point and Elba Island facilities do not reopen under either scenario.

Sensitivity Analysis

The importation of competitively priced natural gas (including gas from Alaska) from a large, diverse resource base has a profound impact on the lower-48 supply/demand balance. In addition, it is a significant factor in determining the direction of flow within the integrated pipeline system. Two sensitivity analyses were performed relative to the moderate energy growth scenario (NPC Reference Case 1) to better understand the impact:

1. **Aggressive Imports** to the lower-48 states assumed: Estimates of the Canadian resource base were increased by 50 percent and potential pipeline capacity doubled by 2010; Mexican gas production increased more quickly leading to reduced purchases from the United States and faster return of imports by the United States; and a higher Canadian exploration and development reinvestment ratio (from 75 to 85 percent).
2. **Restrained Imports** to the lower-48 states assumed: the maximum pipeline capacity from Canada is 2.1 TCF in 1995 and 2.4 TCF in 2010 (moderate energy growth scenario is 2.7 TCF in 1995 and 3.7 in 2010); Mexican demand for U.S. gas is higher (similar to the low growth scenario assumptions); and LNG imports are reduced to zero by 2010.

The volume of pipeline gas and LNG imports to the United States for the two sensitivities are presented in Tables 4-6 and 4-7. A comparison of net imports, imports as a percentage of end-use demand, and Gulf Coast

TABLE 4-6

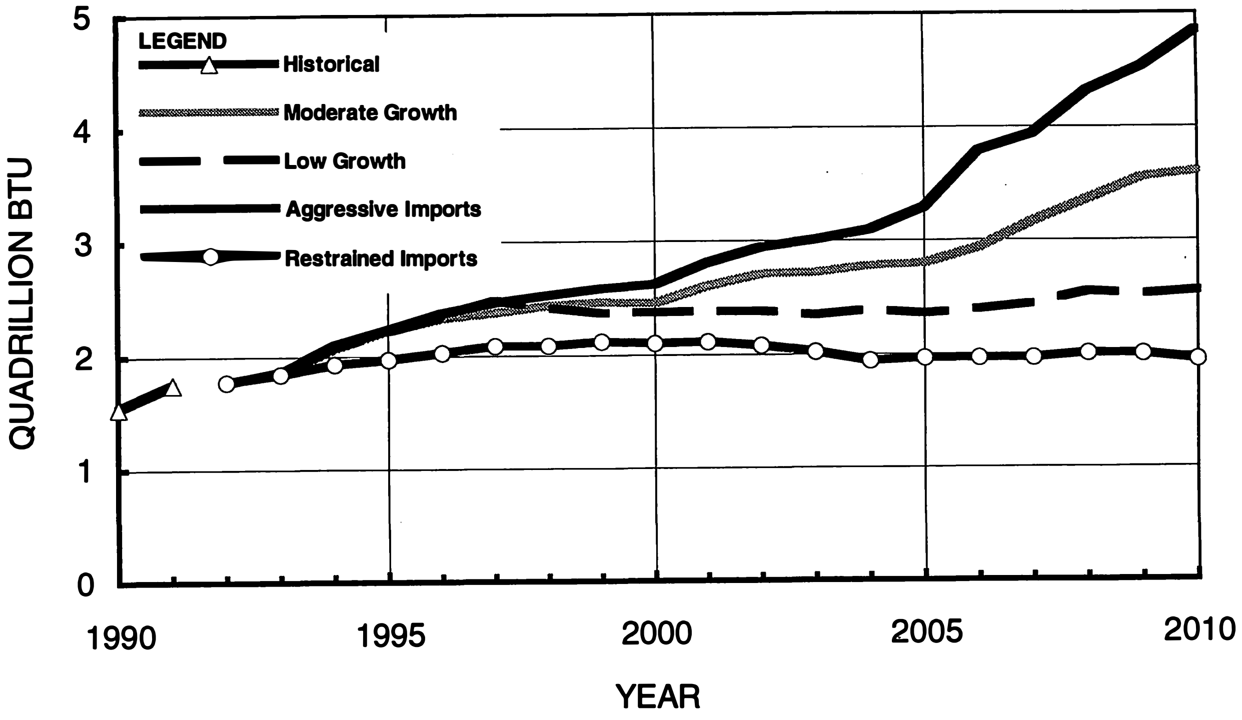
U.S. LOWER-48
NET NATURAL GAS IMPORTS — AGGRESSIVE IMPORTS CASE
(Quadrillion BTU per Year)

Year	Canada	Mexico	Alaska	LNG	Total Net Imports	% of End-Use Demand
1992	1.798	–.113	0	.086	1.771	9.8
1995	2.358	–.258	0	.131	2.231	11.9
2000	2.533	–.185	0	.273	2.621	13.5
2005	2.994	.021	0	.273	3.288	15.5
2010	4.126	.453	0	.273	4.852	21.2

TABLE 4-7

U.S. LOWER-48
NET NATURAL GAS IMPORTS — RESTRAINED IMPORTS CASE
(Quadrillion BTU per Year)

Year	Canada	Mexico	Alaska	LNG	Total Net Imports	% of End-Use Demand
1992	1.798	–.113	0	.086	1.771	9.8
1995	2.143	–.258	0	.086	1.971	10.6
2000	2.358	–.340	0	.043	2.104	10.7
2005	2.352	–.433	0	.043	1.962	9.2
2010	2.459	–.515	0	0	1.944	8.7



	1992	1995	2000	2005	2010
Moderate Growth	1.771	2.227	2.457	2.800	3.603
Low Growth	1.770	2.220	2.373	2.357	2.552
Aggressive Imports	1.771	2.231	2.621	3.288	4.852
Restrained Imports	1.771	1.971	2.104	1.962	1.944

Figure 4-1. U.S. Lower-48 Net Natural Gas (QBTU/Year).

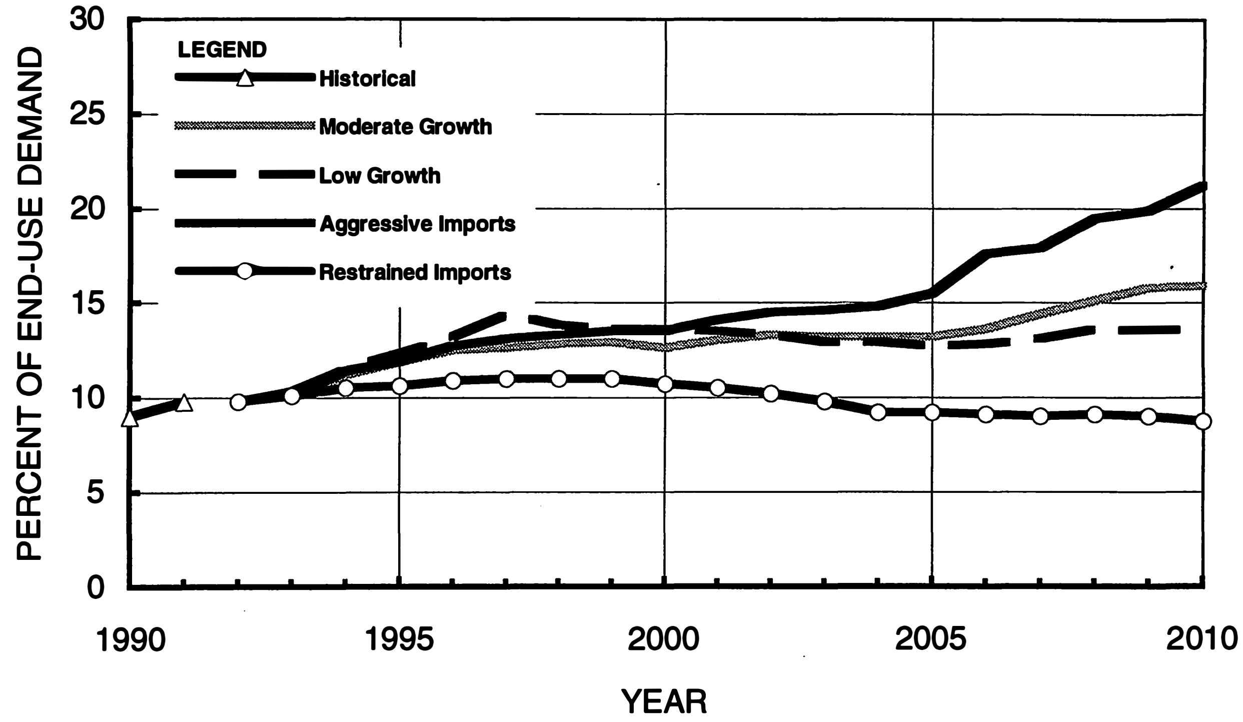
wellhead gas price for the reference cases and the sensitivities are provided as Figures 4-1, 4-2, and 4-3. At the end of the outlook period the Gulf Coast onshore wellhead price differential from the base (i.e., Reference Case 1, moderate growth scenario) is -$0.50 and +$0.25 per MMBTU, and the import supply differential from the base is 1,249 trillion BTU and -1,659 trillion BTU for the Aggressive Imports Case and Restrained Imports Case, respectively. The sensitivities represent a $0.75 swing in price and a 2.908 QBTU swing in volume.

Lower-48 demand is relatively unaffected by the changes in import assumptions. By 2010, there is only a 0.501 QBTU swing in demand volume between the two sensitivity cases, as shown in Figure 4-4. Since demand is relatively stable, variations in import volumes must be balanced by opposite and nearly equal changes in lower-48 production (Figure 4-5). The import sensitivities cause a 2.494 QBTU swing in production volume by the end of the study period.

In both sensitivities, the impact of oversupply or constrained supply to the United States is not realized until after 2000. The most significant contributors to the delay in realizing the shift are the momentum of the industry; the existing investment profile; and time to respond and initiate new projects. Directional shifts in the transportation system are observed within the United States, particularly in the Southwest and Midcontinent. In addition, new interconnections, debottlenecking, and new pipelines are justified.

Conclusions

The North American natural gas resource base is quickly becoming integrated with the market. It is now possible to transport natural gas from Canada to Mexico or to any market



* Total deliveries to consumers (excludes lease and plant fuel, and pipeline fuel).

	1992	1995	2000	2005	2010
Moderate Growth	9.8	11.9	12.6	13.2	15.9
Low Growth	9.8	12.3	13.6	12.7	13.6
Aggressive Imports	9.8	11.9	13.5	15.5	21.2
Restrained Imports	9.8	10.6	10.7	9.2	8.7

Figure 4-2. U.S. Lower-48 Net Natural Gas Imports (% of End-Use Demand).*

location in North America due to improved pipeline efficiencies, regulatory changes, and cooperation between governments. The efficient utilization of natural gas resources will be vital to continued economic growth in the United States and North America. The cooperation of regulatory and governmental agencies is essential for successful importation of incremental supplies of natural gas, and outstanding free trade issues must be resolved.

Natural gas from Canada, Mexico, and Alaska will be capable of providing the U.S. lower-48 with supplemental supplies well into the 21st century. The resources in these regions almost double the supply base available to the lower-48 states. The current proved reserves are substantial and well defined. Additional resources will be developed and produced when economically justified to meet the incremental demand to supply the export marketplace. Pipeline and border crossing infrastructure is in place and can be expanded to meet the demand growth.

Net imports of gas by pipeline from Canada and Mexico could easily capture 12 to 15 percent of the U.S. market by 2010. An additional 5 percent of the market would be served under a more aggressive import scenario. Development and delivery of Canadian frontier gas and Alaskan gas would not be economical until after 2010.

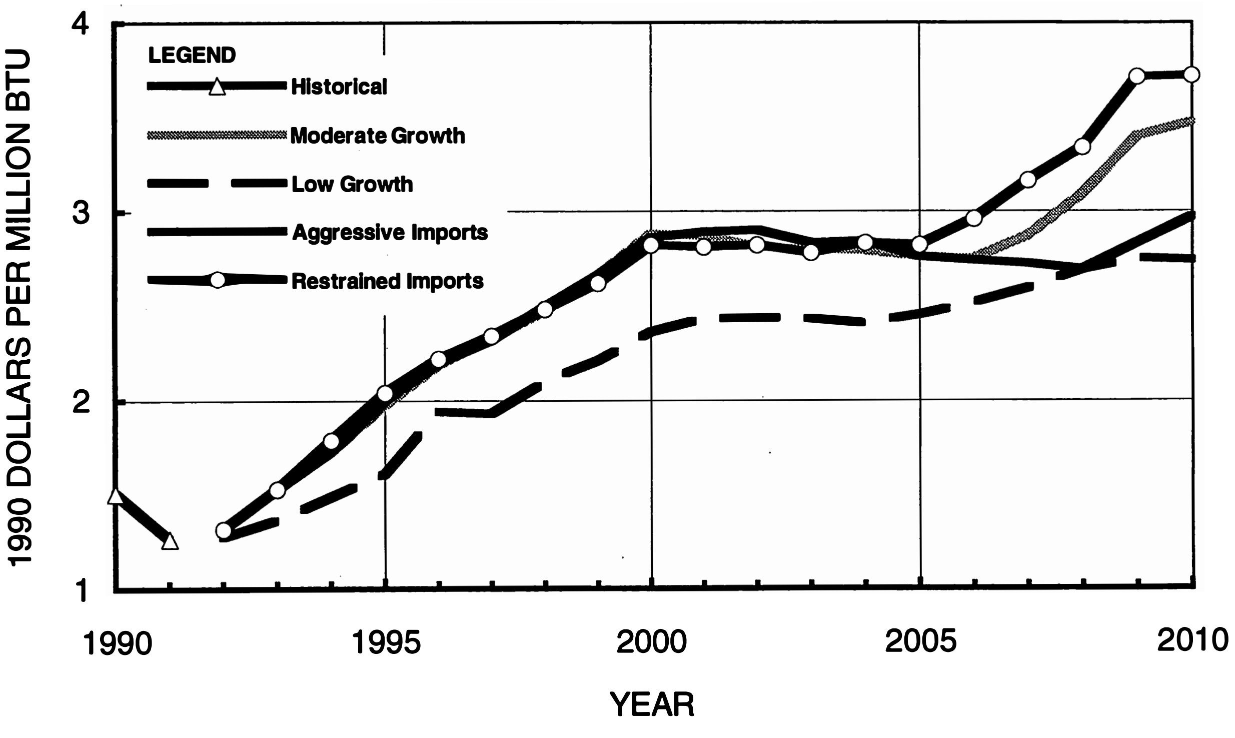
The importation of LNG from the Atlantic Basin will remain a relatively small part of the U.S. natural gas supply picture, providing less than 2 percent of U.S. requirements through 2010. It will provide supply for peak shaving as well as baseload supply to certain customers located in the market areas served by the terminals.

CANADA

Summary

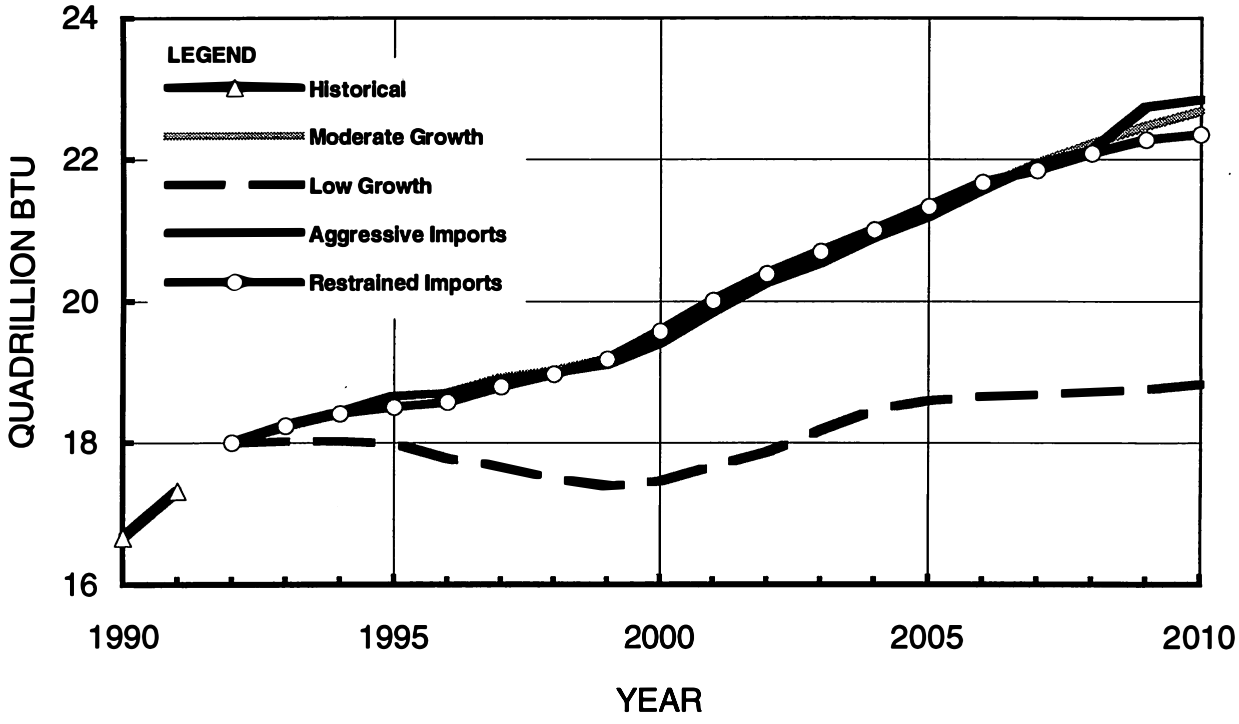
The discovery of natural gas in Canada dates back to 1880, but large scale development did not occur until after the discovery of the Leduc oil field in Alberta in 1947. Since then, the natural gas industry has developed in a manner similar to the U.S. lower-48. By 1958 the TransCanada pipeline was completed, linking western Canadian supplies to the major population and industrial areas of eastern Canada and the U.S. Northeast. In 1961 the Alberta Natural Gas/Pacific Gas Transmission pipeline was completed to California, and in 1982 the Foothills/Northern Border pipeline to the U.S. Midwest was constructed. These developments have essentially integrated Canadian and U.S. lower-48 natural gas supplies into a consolidated North American natural gas market.

Canada has abundant established reserves of natural gas and enormous potential for undiscovered resources in both the Western Canada Sedimentary Basin (WCSB) and in the northern frontier areas. Estimates of recoverable resources, given expected technological development through 2010, include conventional resources in the WCSB numbering 71 TCF proved (with less than 1 TCF in Eastern Canada), 109 TCF remaining undiscovered in new fields, and 24 TCF to be gained from appreciation in existing fields. Conventional frontier area resources are estimated to be 317 TCF from both known and undiscovered reservoirs. In addition to these conventional resources, nonconventional resources have been estimated by some experts to be as high as 3,000 TCF. For this study, estimates of 129 TCF of coalbed methane and 89 TCF of tight sands resources were utilized.



	1992	1995	2000	2005	2010
Moderate Growth	1.32	1.98	2.88	2.76	3.47
Low Growth	1.28	1.61	2.36	2.45	2.74
Aggressive Imports	1.32	2.00	2.86	2.76	2.97
Restrained Imports	1.32	2.04	2.82	2.82	3.72

Figure 4-3. Gulf Coast Wellhead Gas Price (1990$/MMBTU).



* Total deliveries to consumers (excludes lease and plant fuel, and pipeline fuel).

	1992	1995	2000	2005	2010
Moderate Growth	18.001	18.666	19.555	21.287	22.682
Low Growth	17.998	17.997	17.451	18.596	18.829
Aggressive Imports	18.007	18.665	19.418	21.199	22.849
Restrained Imports	18.007	18.505	19.579	21.335	22.348

Figure 4-4. U.S. Lower-48 Natural Gas End-Use Demand (QBTU/Year).*

In 1991, exports from Canada to the United States totaled 1.761 QBTU, an 18 percent increase over the 1990 level. Assuming moderate energy growth (Case 1) in the United States, total imports from Canada are expected to increase to 2.562 QBTU by 2000 and 3.268 QBTU by 2010. Under the low energy growth scenario (Case 2), total import volumes increase more slowly in the latter years of the forecast period, to 2.505 QBTU by 2000 and only 2.832 QBTU in 2010.

The price of the Canadian gas (1990$) at the Alberta/Saskatchewan border (Empress) also increases in the moderate energy growth scenario, from $1.06/MMBTU in 1991 to $2.46/MMBTU in 2000 and $2.79/MMBTU in 2010. The rise in the Empress price has significance for most of Canada's gas exports as it is the major receipt point for the TransCanada Pipeline, which feeds all export points to the U.S. lower-48 except those on the West Coast. In the low energy growth scenario, the reduced demand and import volumes are reflected in a more gradual price escalation. The average price at the Empress receipt point increases to only $2.18/MMBTU by 2010.

Based on the sensitivity analyses performed for this study, future Canadian natural gas export trade will more likely be constrained by economic conditions, including gas-on-gas competition in the United States, and by Canadian government regulations regarding reserve dedication, than by the level of proved reserves and potential resources in Canada.

Introduction

Historical Perspective

The discovery of natural gas in Canada dates back to 1880 in southern Ontario where gas was marketed in the general vicinity and even exported in small quantities to the United

States. In 1884 gas was discovered in Alberta and commercial production began about 1904. Supplies of gas were first drawn from shallow wells at Medicine Hat. In 1909 the Bow Island field was discovered and three years later a 170-mile, 16-inch diameter line was built to transport natural gas to Calgary.

Gas had been detected in the Turner Valley in Alberta at a very early date, but the discovery well was not drilled until 1913. Extensive development of the Turner Valley did not begin until 1936 when oil was discovered there, and at least 1 TCF of natural gas was estimated to have been flared at the wellhead by the late 1930s. Dry gas was found in the Kinsella area in 1914 and transmission to Edmonton commenced in 1923.[1]

Natural gas was also found in other areas of western Canada. Smaller fields in Saskatchewan have historically supplied nearby communities with gas for heating and for light industry. As more gas fields were discovered, development occurred for use in larger cities (Regina, Saskatoon, and Prince Albert). However, it was not until the late 1940s and early 1950s that production from fields in British Columbia started to grow and was connected with markets in the Vancouver area.

Large scale gas use in Canada began in Alberta in 1947 and developed in a similar manner to gas use in the United States. By 1947, several TCF of natural gas reserves had been found in Canada. The widespread exploration for oil in the WCSB, subsequent to the discovery of the Leduc oil field in 1947, also resulted in proving large additional reserves of gas in the region.[2] With the development of long distance transportation of natural gas by

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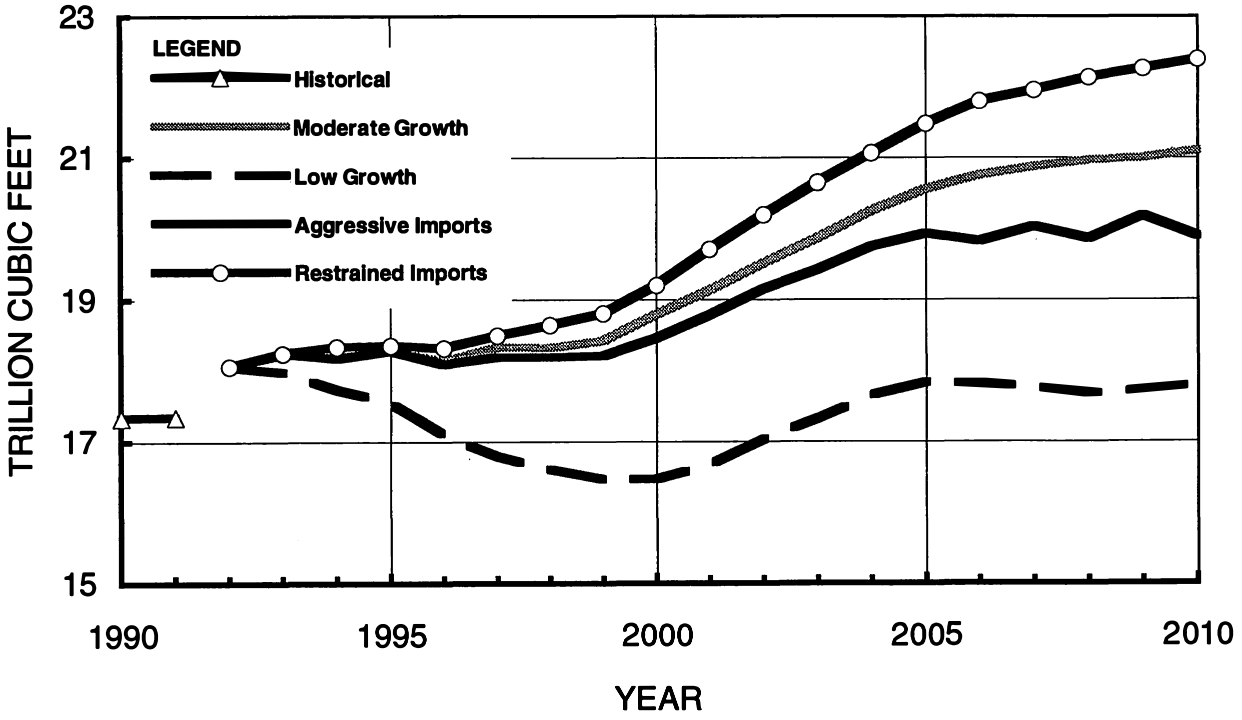
[1] John Davis, *Canadian Energy Prospects*, Royal Commission on Canada's Economic Prospects, March 1957, pp. 158-159.

[2] *Canada Royal Commission on Energy*, First Report, October 1958, First Report, Chapter 1, "Export of Natural Gas and Crude Oil," pp. 1-1 and 1-2.



	1992	1995	2000	2005	2010
Moderate Growth	18.065	18.295	18.794	20.564	21.100
Low Growth	18.062	17.554	16.471	17.842	17.808
Aggressive Imports	18.071	18.286	18.460	19.936	19.902
Restrained Imports	18.071	18.360	19.209	21.476	22.396

Figure 4-5. U.S. Lower-48 Natural Gas Production (TCF/Year).

pipeline, it soon became feasible to market gas from western Canada to the larger consuming areas of North America. By 1958 the Trans-Canada Pipeline was completed linking the western Canadian supply areas to the major population and industrial areas in the eastern provinces of Ontario and Quebec. In 1961 the Alberta Natural Gas/Pacific Gas Transmission pipeline to California was completed, and in 1982 the Foothills/Northern Border pipeline to the U.S. Midwest was constructed.

The 1980s was a decade of significant change for the North American natural gas industry. Much of the market/price volatility was associated with a transition from a heavily regulated industry to one characterized by decreasing government controls. The industry has also survived difficult economic conditions and acute supply/demand imbalances.

Canadian Markets

Canadian gas production increased steadily during the 1980s. The role of natural gas in Canada's energy mix has also been growing since the mid-1980s, but current low market prices are limiting gas development.

Alberta is endowed with large resources of natural gas. Marketable natural gas production reached 3.7 TCF in 1991, up 4 percent from 1990. But with the sharp drop in exploratory drilling last year, gas reserve additions were the lowest in four years.

There are three principal markets for Canadian gas (1991 volumes are shown):

1. Western Canadian markets in the producing provinces of Alberta, British Columbia, and Saskatchewan (0.93 TCF, or 25 percent)
2. Eastern Canadian markets, principally in Ontario and Quebec (1.0 TCF, or 27 percent)
3. Export markets in the United States (1.710 TCF, or 45 percent).

The balance of the production is used as fuel in the producing fields and as pipeline transportation fuel.

Canadian gas consumption is centered in Alberta in the west and around southern Ontario and Quebec in the east; these two areas account for about 70 percent of total Canadian demand. Western Canadian markets show some similarities to gas markets in the U.S. Southwest—the region has a high concentration of refining, petrochemical, and other energy-intensive industries that consume large quantities of gas year-round. The remaining residential and commercial markets are highly seasonal, given the extreme weather swings in the region. Gas used for electricity generation is not significant since this market is dominated by coal, nuclear, and hydro-power.

Eastern Canadian markets resemble those of the U.S. Pacific region (California, Oregon, and Washington) with more balance between industrial and residential/commercial markets. The large industrial sector in Ontario comprises almost 50 percent of the provincial market. Residential and commercial markets are highly seasonal, accounting for the other half of consumption in the area. As in western Canada, gas used for electricity generation is insignificant.

Future overall Canadian domestic gas demand growth through 2010 is projected to be moderate (around 1.0 percent per year) by both the National Energy Board of Canada (NEB) and the Canadian Ministry of Energy, Mines and Resources. For the NPC study, we have used the NEB's estimate for total annual average growth rate of 0.8 percent per year.[3] Both of their forecasts project some limited growth in residential and commercial markets as population grows and the economy improves, but growth in the industrial sector will be partly offset by improvements in energy efficiency and a shift away from energy-intensive industries due to environmental concerns and industrial restructuring. Neither of these agencies projects any significant penetration for natural gas into the electrical generation market.

Under this scenario, annual Canadian domestic natural gas consumption is expected to grow to a range of 2.4 to 2.5 TCF by 1995 and from 2.6 to 2.8 TCF by 2000.

Regional U.S. Markets

Canadian natural gas exports in 1991 set a record for the fourth year in a row. Shipments

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[3] *Canadian Energy – Supply and Demand 1990-2010*, National Energy Board, June 1991, Chapter 4, "Energy Demand," p. 70.

of gas to the United States (Canada's only export customer) jumped 18.1 percent in 1991 to 1.710 TCF, exceeding the previous record 1.448 TCF exported in 1990. Canada's share of the U.S. end-use market in 1991 increased to 9.9 percent, up from 8.7 percent in 1990, 7.9 percent in 1989, 7.9 percent in 1988, 6.4 percent in 1987, and only 5.1 percent in 1986. This growth is one result of more market-oriented pricing and recent expansions of cross-border pipeline capacity.

Of the total 1.710 TCF Canadian exports to the United States in 1991, 53 percent was delivered under long-term contracts at an average price of $2.06/MMBTU, and short-term or spot markets accounted for 47 percent at $1.63/MMBTU.[4]

Canadian gas exports reach most major U.S. markets, including California, the Pacific Northwest, the Midwest, and the Northeast. By supplying these market areas, Canadian exports indirectly affect supply and prices in the major gas producing regions of the lower-48 (like the Southwest, Gulf of Mexico, and Rockies). Direct customers of Canadian gas include utilities and pipelines, as well as both large and small industrial end users, including cogeneration facilities. While exports have been growing recently, there have not been large seasonal swings in exports—reflecting the "baseloading" of competitively priced Canadian gas in these markets.

Canadian Gas Resources

Background

Canadian natural gas reserves and potential resources are enormous relative to its current markets, especially in comparison to the United States. Canadian established reserves and potential/ultimate resources are shown in Table 4-8. Proved (established) reserve estimates are reported by the Canadian Petroleum Association, while undiscovered conventional resources are estimated by the NEB and the Geological Survey of Canada. In the past, frontier resources and ultimate potential were estimated by the Canadian Oil and Gas Lands Administration, but this organization was merged with the NEB in 1991. Various other organizations, including private companies, make estimates of the nonconventional resources in Canada.

Proved reserves are defined somewhat differently by Canadian government agencies than by those in the United States. Canada includes all resources that have been found from drilling as proved reserves, even though they may be located in remote frontier areas that are not yet accessible or economic to market regions. Also included as proved reserves are both "connected" and "unconnected" accumulations that have been identified, regardless of economic conditions. Established reserves are that part of the discovered recoverable resource base that is estimated at a point in time to be economically recoverable using known technology under present and anticipated economic conditions.

Undiscovered recoverable conventional resources are those that are estimated at a point in time to be recoverable using conventional technology from accumulations that are believed to exist on the basis of available geological and geophysical evidence but have not yet been shown to exist by drilling, testing, or production.[5]

The 1991 shortfall that occurred between gas production and reserves replacement in Canada is the first since 1987. The development of Canadian natural gas for export depends upon the size and location of the various supply regions. While they are not currently marketable, Canadian gas exports in the future suggest that Northern Canadian frontier supplies (e.g., Mackenzie Delta) may be necessary to fulfill North American demand requirements.

The estimated Canadian natural gas resource base used for the NPC Reference Cases (using both current and 2010 technology) is shown in Table 4-9. Figure 4-6 shows the resource estimates assuming 2010 technology.

Conventional Resources: Western Canada Sedimentary Basin

The major oil and gas producing area of Canada is the Western Canada Sedimentary Basin, which underlies most of Alberta and

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[4] *Canadian Energy – Supply and Demand 1990-2010*, National Energy Board, June 1991, Chapter 6, "Natural Gas," pp. 120-122.

[5] Ibid.

TABLE 4-8

EXISTING ESTIMATES OF CANADIAN NATURAL GAS RESOURCES AS OF DECEMBER 31, 1990
(Trillion Cubic Feet)

	Established Reserves	Remaining Undiscovered	Total
Conventional Gas			
Western Canada Sedimentary Basin			
British Columbia	8	22	30
Alberta	60	70	130
Saskatchewan	3	4	7
Others (Including Ontario)	1	—	1
WCSB Subtotal	**72**	**96**	**168**
Frontier Areas			
West Coast	—	10	10
Mainland Territories	—	11	11
Mackenzie/Beaufort	11	57	68
Arctic Islands	14	98	112
Hudson Bay	—	3	3
Newfoundland Offshore	—	59	59
Nova Scotia Offshore	—	23	23
Frontier Subtotal	**25**	**261**	**286**
Conventional Subtotal	**97**	**357**	**454**
Nonconventional Gas			
Western Canada Sedimentary Basin			
Coalbed Methane	—	129+	129+
Tight Gas	—	89	89
Nonconventional Subtotal	**—**	**218+**	**218+**
Total Resources	**97**	**575+**	**672+**

SOURCES: Proved Reserves – Canadian Petroleum Association (June 1991).
Undiscovered Conventional Resources – National Energy Board – Geological Survey of Canada.
Frontier Ultimate Potential – Canadian Oil & Gas Lands Administration (1990).
Nonconventional Resources – Total coalbed methane resources may be as high as 3,000 TCF.

parts of northeastern British Columbia and the southern half of Saskatchewan.

Gas reservoirs in the WCSB tend to vary widely in depth, quality, size, and location. With current annual production of about 3.7 TCF and established reserves of 71 TCF, the WCSB boasts a reserves-to-production ratio of almost 20 years, compared to less than 10 for the U.S. lower-48 states. Approximately 40 percent of the Canadian gas reserves identified to date are sour (i.e., contain hydrogen sulfide).

There is significant upside potential for natural gas reserve additions in the WCSB. Estimates of ultimate recovery from known fields (cumulative production plus proved reserves at a specific date) generally grow over time. Such reserve appreciation occurs as a result of reserve additions from field extensions and new reservoirs, positive revisions due to infill drilling, improved technology and enhanced recovery techniques, well workovers, recompletions, and longer productive life of wells

TABLE 4-9

NPC ESTIMATES OF CANADIAN NATURAL GAS RESOURCES AS OF DECEMBER 31, 1990

(Trillion Cubic Feet)

	Current Technology	2010 Technology
Proved Reserves	**72**	**72**
Conventional Gas		
Reserve Appreciation	22	24
New Fields	99	109
Frontier	293	317
Subtotal	**414**	**450**
Nonconventional Gas		
Coalbed Methane	80	129
Tight Gas	55	89
Subtotal	**135**	**218**
Total Resources	**621**	**740**

Basis —Technically recoverable resources incorporating technology advancement through 2010.

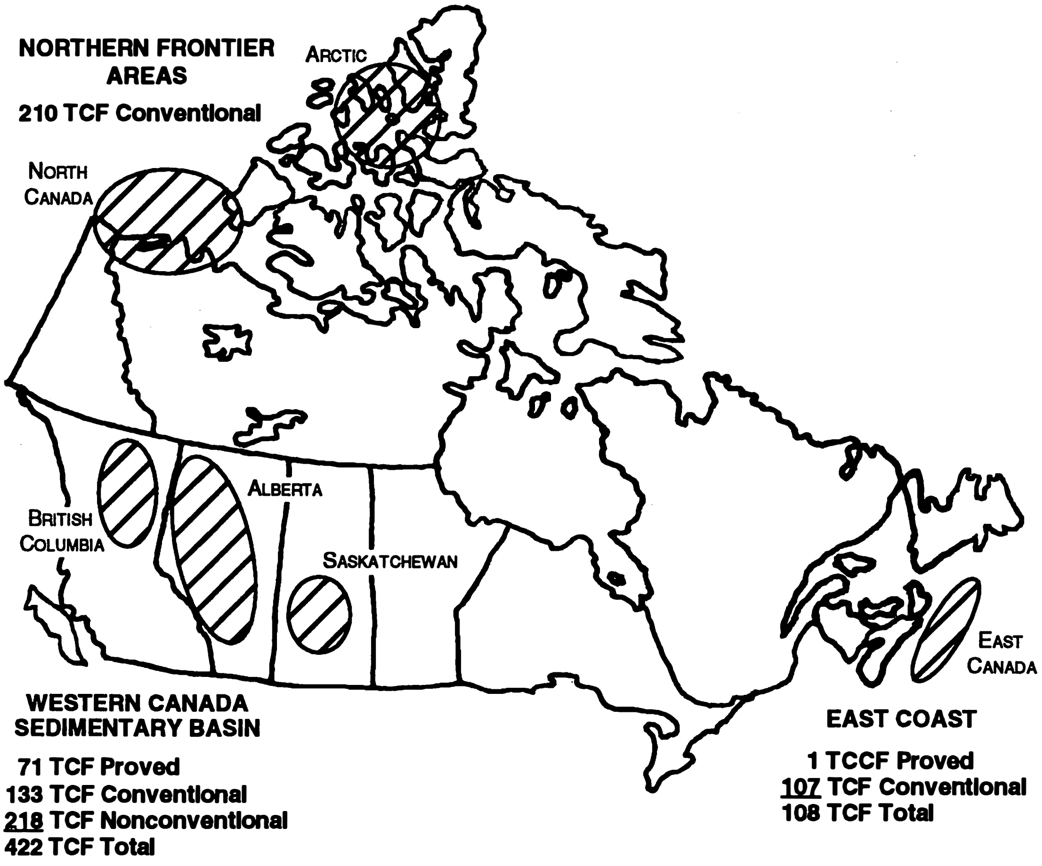

Figure 4-6. Canadian Natural Gas Resources (2010 Technology).

encouraged by higher prices. The additional volume reflects the expected reserve appreciation, or the incremental gains expected to be added over time, to known fields. This study is based on an estimate of 24 TCF reserve appreciation from existing fields in Canada.

Frontier Resources

Canadian frontier areas are also rich in natural gas. Abundant resources in the frontier regions provide for potential development of already discovered and anticipated future significant exploratory discoveries. As conventional resources in the lower-48 states, Mexico, and Canada are depleted, more efforts will be made to develop gas from the northern Canadian frontier areas and Alaska. Exploration and drilling activity in the Mackenzie Delta/Beaufort Sea area and the Arctic Islands has identified about 29 TCF of the total 317 TCF. No pipeline currently exists to move these resources to market areas, resulting in very limited exploration activity to date.

Offshore Eastern Canada also has the potential for significant natural gas production. Several sizable accumulations of oil and gas have already been discovered. However, development has been occurring slowly and cautiously due to economic and operating conditions. Annual development time from these fields is currently limited due to severe weather conditions. As economic conditions improve and technology advancement continues, Offshore Eastern Canada could become an important producing region—particularly for eastern U.S. and Canadian markets. Assuming advanced technology, available resources in this area could reach 108 TCF by 2010.

Potential/undiscovered resources in all these areas are enormous considering Canada's relatively short history as a major gas producer. It has been estimated that Canada's sedimentary basins have been drilled only about one-seventh as intensely as U.S. lower-48 sedimentary basins. However, the most important factor affecting frontier resource development is the high cost required to find, develop, and transport this gas to market areas. Nonetheless, these remotely located resources will most likely compete economically with deepwater Gulf of Mexico and nonconventional resources in meeting future North American gas demand.

Nonconventional Resources: Coalbed Methane and "Tight" Gas

Beyond the conventional resources already discussed, Canada has huge potential for gas from nonconventional resources such as coal seams and "tight" (very low permeability) formation gas—especially in the WCSB. Estimates of these resources are somewhat preliminary since there has been only limited development to date, due to the abundance of conventional resources.

Success in coalbed methane production in the lower-48 has helped spur the Canadian industry to look for comparable opportunities. However, these resources have no federal tax subsidies as they currently do in the United States. The Alberta Geological Society has conducted a study of the province's coalbed methane potential. The study ranks the best prospects and the volume of gas that is likely to occur corresponding to different grades of coal. The resulting estimate was that there is potentially 2,000 to 3,000 TCF of coalbed methane resources in Alberta. By comparison, the Alberta Energy Resources Conservation Board (ERCB) estimates the province's remaining conventional gas potential at 170 TCF.

The ERCB has formed a public-industry-government group to monitor coalbed methane development in the province, although to date there has been little evaluation of the methane productivity of Alberta coal seams.

The potential for nonconventional resource development is enormous, but these estimates are highly theoretical and controversial within the industry. Alberta coal seams tend to be deeper (therefore higher volumes), but probably of lower quality than the coalbed methane found in the San Juan Basin of the United States. The relative abundance of low-cost conventional supplies will most likely delay the need for development of Canadian nonconventional supplies until well into the next century.

This study assumes that there are 129 TCF of coalbed methane and 89 TCF of "tight" formation gas available for recovery. Compared to some estimates, these values are fairly conservative, but they do fall within the range of most industry judgments. It should be noted that there is tremendous up-side potential for these resources in the future, especially with technology improvements and production experience of the lower-48 states.

Regulatory Environment

Background

Canadian natural gas export policy is set by the National Energy Board of Canada, an agency created by the National Energy Board Act of 1959. The NEB frequently calculates estimates of proved reserves, trends in the discovery of natural gas, and demand requirements.[6]

During the first half of the 1980s, natural gas prices for interprovincial and international trade were set by a federal-provincial agreement. During this period, Canadian natural gas supply and deliverability were at all time highs, and gas trade with the United States was very active. North American natural gas markets started to strain due to low oil prices, economic downturns, inflexible long-term gas contracts, pervasive regulation, and surplus deliverability. Demand for gas fell as supply capability grew, and a shortage turned into a surplus.[7]

Deregulation of the Canadian gas industry started in 1984 and is now essentially complete on the federal level; provincial regulations remain somewhat more restrictive with respect to reserve dedication. Future Canadian natural gas trade with the United States could be constrained by competitive conditions in U.S. markets and by regulations (Canadian and/or U.S.); the level of reserves and resources is less of an issue.

Canadian Provincial

By federal-provincial agreement, the Provinces "own" the resources and receive royalty payments. The Canadian provincial governments regulate the removal of gas from the provinces, regardless of whether the gas is destined for Canadian or U.S. markets. In Alberta, the ERCB issues Energy Removal Permits and the Alberta Department of Energy advises the provincial Minister of Energy whether to approve the permits. Similar regulations are in place in British Columbia (B.C.), where the Ministry of Energy, Mines, and Petroleum Resources issues Energy Removal Certificates (there is no B.C. counterpart to the ERCB).

In processing an application for a removal permit, the following requirements must be met:

- Contract pricing terms are market sensitive and in the public interest.
- All downstream transportation contracts are in place.
- The applicant shows established reserves for 100 percent of the proposed volumes for the full term of the removal permit (typically 2 to 15 years).
- The proposed exports from the province are surplus to the cumulative needs of the provincial core market (residential, commercial, and small industrial) for the term of the removal permit.

Historically, the requirement to maintain reserves to meet 25 years of domestic needs was the major reason for the very high reserves-to-production ratio that characterized the Canadian industry. With the deregulation of the industry, these requirements have been relaxed considerably. While provisions to maintain reserves in support of contracts exceeding two years and to meet provincial core market requirements are still in place, this regulatory framework offers the industry sufficient flexibility to accommodate an erosion of the Canadian reserves-to-production ratio toward the level experienced in the United States and thought to be compatible with a competitive market.

The regulations in Alberta and British Columbia are similar. The major difference is that B.C. requires only the first five years of the proposed exports to be "established." The remaining volumes may be outlined in a gas exploration and development plan.

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[6] Boyce Greer, *Natural Gas Trade in Transition*, Harvard University – International Energy Studies, 1987, Chapter 5, "North American Natural Gas Markets in Transition: A Conference Report," report presented at Mexico City, May 1984, pp. 46-47.

[7] Leonard A. Coad and David H. Maerz, *Continental Natural Gas Market – Canadian Export Capacity in the 90s*, Canadian Energy Research Institute, Study No. 32, October 1989, pp. 1-2.

Canadian Federal

The NEB is the Canadian federal agency responsible for regulating Canada's energy industry, much like the Federal Energy Regulatory Commission (FERC) in the United States. The NEB's responsibilities include regulation of the oil, gas, and electricity industries, as well as advising the federal government on the development and use of Canada's energy resources.

NEB regulation of gas exports to the United States covers two areas: facilities and gas volumes. The NEB must authorize the construction and operation of new interprovincial pipeline facilities to the Canada-U.S. International Boundary, similar to the FERC authorizing new interstate pipeline construction in the United States. In pipeline certification proceedings, the NEB addresses such issues as capital costs, tolling (rates), depreciation rates, and whether the facilities will be used and useful over their life.

The NEB must also specifically authorize the export of the gas volumes from the country by issuing an export license for up to 15 years. The export license process was historically a long, complicated procedure involving a number of market surplus tests, deliverability tests, and social/economic cost-benefit analyses. The purpose of these tests was to satisfy the federal government that the gas to be exported was surplus to the reasonably foreseeable Canadian domestic requirements and that the export sale would generate net economic benefits for Canada. These export regulations have been relaxed considerably in recent years, reflecting the general deregulation of the continental gas market and Canada's commitment to free trade with the United States. The current "market based procedure" for export approval is based largely on a complaints mechanism. The general criterion for NEB intervention in privately negotiated export arrangements is whether or not Canadian consumers have comparable access to gas supplies under the same contract terms and conditions as the proposed export sale. The NEB also must be satisfied that there are adequate supplies and markets to fulfill the contract, that the contract pricing terms are market-responsive, and that authorization of the export will not have adverse effects on Canadian gas consumers.

U.S. Federal

The U.S. Department of Energy (DOE) Office of Fossil Energy, has authority over imports and exports of natural gas. The DOE evaluates natural gas import and export applications in accordance with the public interest requirements of Section 3 of the Natural Gas Act of 1938. Section 3 requires approval of imports and exports unless there is a finding that it "will not be consistent with the public interest." Thus, Section 3 establishes a statutory presumption in favor of authorization.

In processing gas import requests, the DOE applies three basic criteria in its review: (1) the overall competitiveness of the import arrangement in the market(s) to be served, (2) the need for the gas, and (3) the security of the supply. With regard to export requests, the DOE considers domestic need for the gas as well as any other issues determined to be appropriate in a particular case.

In October 1992, President Bush signed the "Energy Policy Act of 1992." This Act revises Section 3 of the Natural Gas Act by making a statutory finding that natural gas imported from or exported to a country with which "there is in effect a free trade agreement requiring national treatment for trade in natural gas," as well as imports of liquefied natural gas, are in the "public interest" and such applications for authorities "shall be granted without modification or delay."

In conclusion, although there are numerous regulatory agencies involved in the Canada-U.S. gas trade, the processing of applications usually proceeds fairly smoothly because all prospective exporters and importers are aware of each agency's requirements. Thus, prospective Canadian exporters typically come to the Canadian regulators with signed contracts for markets, dedicated supplies and downstream transportation, and the rigors of market competition usually ensure that the pricing terms reflect "market values" and are responsive to changes in market conditions. Therefore, the usual obstacles to new exports (or the extension of an existing export arrangement) are the "bureaucratic lag," which can reach as much as six months to one year with the NEB, and the normal lead-time needed to construct new pipeline facilities to growing gas markets.

Canadian Export Capacity

Current Capacity

U.S. imports of Canadian gas are currently constrained by cross-border pipeline capacity, which now totals about 2 TCF per year estimated at 100 percent load factor. Figure 4-7 and Table 4-10 show the major import points and pipelines, the current design capacities, and the annual flows and load factors for 1987-1991. Additional export capacity that is either currently under construction or planned to be constructed in the near future could boost capacity up to around 3.0 TCF per year.

Average load factors at the existing major import points have been extremely high in recent years, reflecting among other things, the competitiveness of Canadian supplies in regional U.S. markets. This is due in part to the Canadians' acceptance of a price-taker role in most export markets. With a large surplus of established reserves and the Canadian regulators' relaxed export policies, Canadian gas has the potential to play an even larger role in certain U.S. markets.

According to a recent Canadian Energy Research Institute study, rising export sales and pipeline expansions will reduce the excess of Canadian deliverability relative to demand from 875 BCF in 1990 to 640 BCF in 1993, and 425 BCF by 1995. However, productive capacity will increase from 2.6 TCF in 1990 to 3.1 TCF by 1995. Most new capacity will go to U.S. markets. Export volumes will rise from 1.6 TCF in 1990 to 2.2 TCF in 1995.[8]

Most of the recent increase in exports has occurred in the Midwest through Monchy, Saskatchewan (Port of Morgan, Montana) and Emerson, Manitoba (Noyes, Minnesota). The largest percentage increase in exports was to the U.S. Northeast through Niagara Falls. Long-term sales at Niagara Falls, New York, increased 73 percent in 1991 to 84 BCF, while short-term sales more than doubled to 95 BCF. The 1991 increase was due primarily to expanded pipeline capacity and increased sales to gas-fired cogeneration facilities. British Columbia gas exports to the Pacific Northwest have also increased through Huntingdon, British Columbia (Sumas, Washington). Gas exports through Kingsgate, British Columbia (Eastport, Idaho), mostly destined for California markets, have fallen off slightly due to long-term contract supplies dropping by more than 10 percent in 1991 even though short-term sales doubled.

Regionally, 30 percent of Canadian export gas in 1991 was sold to California markets. The Pacific Northwest and Mountain regions accounted for 13 percent, while the Midwest took 42 percent of the Canadian gas exported, and the Northeast 15 percent.

New and Proposed Pipeline Capacity

A major jump in exports occurred in 1992 to the U.S. Northeast, with the expansion of Tennessee Pipeline's Niagara Falls facilities and the Iroquois Pipeline system becoming operational in December 1991. Exports are expected to grow in the Midwest during 1993 as the Northern Border pipeline system expands, and in California during 1994 as other pipeline expansions go on line. New pipeline capacity and the timing of the projects is a critical factor in determining how to best serve long-term requirements for natural gas trade between Canada and the U.S. lower-48 markets.

Reflecting the expected demand growth in the United States and abundant supplies in Canada, several pipelines have recently completed, started, or proposed new import capacity. Following is a partial list of these proposed pipeline projects.

- **TransCanada** – Expansion program connecting with the Iroquois system into U.S. Northeast. Gas flowing at 25 percent of capacity in December 1991; by year-end 1992, 641 MMCF/D of gas from western Canada. Another expansion for additional 250 MMCF/D planned for 1995. Corresponding capacity on the TransCanada trunkline will be required for all future projects into the U.S. Midwest and Northeast.
- **Iroquois** – Planned expansion of 150 MMCF/D in 1993 and looping program planned for 1994 would add another 227 MMCF/D to capacity.
- **Northern Border** – Links western Canada to U.S. Midwest via Foothills system. Delivery capacity will increase 22 percent to

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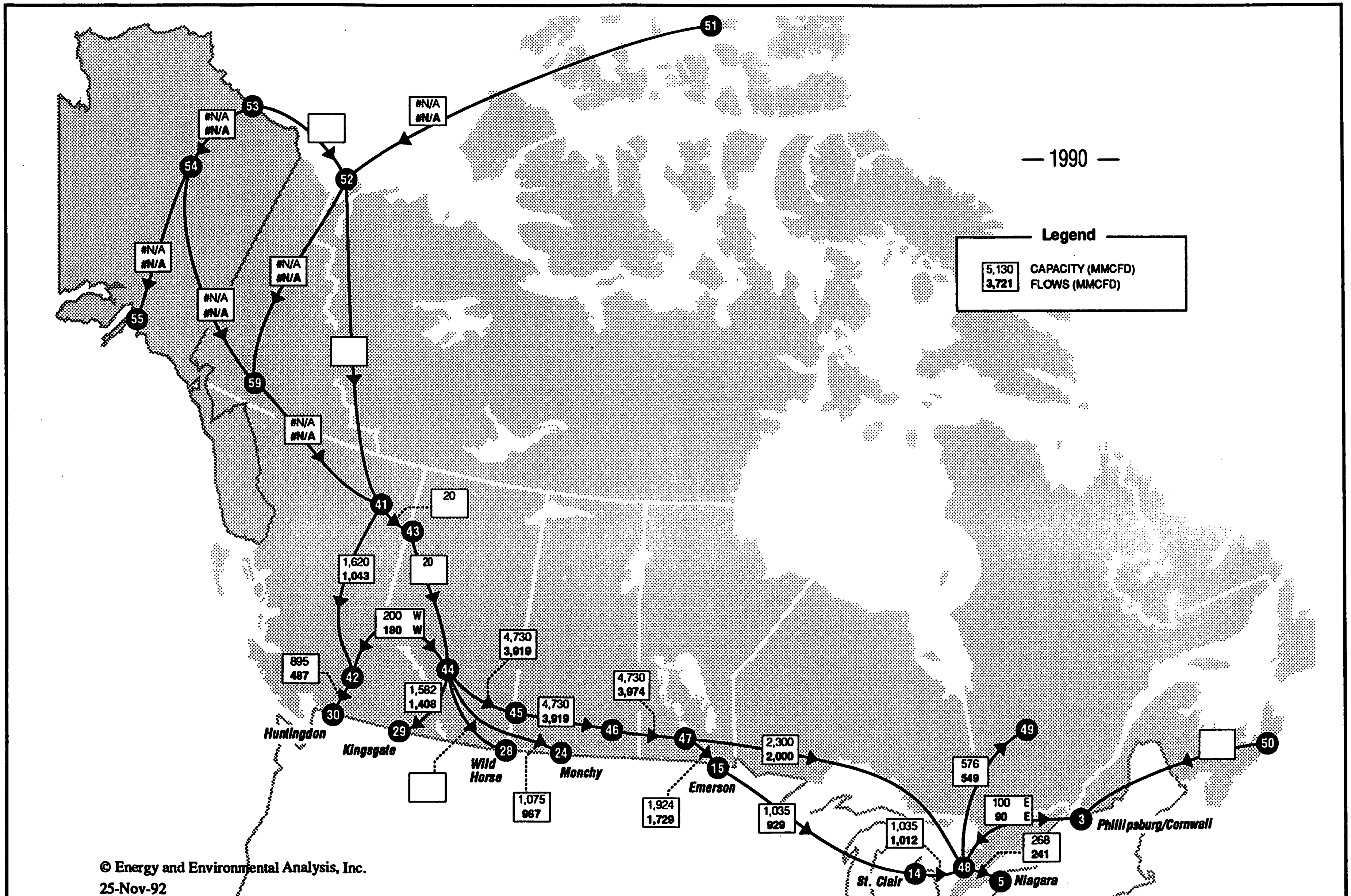
[8] Canadian Energy Research Institute, Study No. 42, February 1992, results reported in *Btu Weekly*, March 16, 1992.



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25-Nov-92

Figure 4-7. Canadian Pipeline Capacity.

TABLE 4-10

HISTORICAL U.S. GAS IMPORTS FROM CANADA

			BCF per Year					Load Factor (%)				
Export Point	**Import Point**	**Pipeline**	**1987**	**1988**	**1989**	**1990**	**1991**	**1987**	**1988**	**1989**	**1990**	**1991**
Kingsgate, B.C.	Eastport, ID	PGT	484.2	503.8	501.8	511.6	497.1	83.7	87.1	86.7	88.4	85.9
Monchy, Sask.	Port of Morgan, MT	Northern Border	171.5	311.0	317.9	336.3	373.2	43.7	79.3	81.0	85.7	95.1
Emerson, Manitoba	Noyes, MN	Great Lakes, Viking	127.0	223.0	250.5	298.3	342.2	38.4	67.5	75.8	83.0	83.2
Huntingdon, B.C.	Sumas, WA	Northwest Pipeline	138.7	136.3	172.3	161.1	215.3	47.5	46.7	59.0	55.2	73.7
Niagara Falls, Ont.	Lewiston, NY	Tennessee	44.4	64.8	59.4	89.9	173.6	69.5	101.4	78.2	91.9	94.0
Iroquois, Ont.	Waddington, NY	Iroquois					4.5					
	Subtotal (TCF per Year)		**0.966**	**1.239**	**1.302**	**1.397**	**1.606**	**58.3**	**74.8**	**78.0**	**81.2**	**86.4**
Various, ALTA	Various, MT	Montana Power	6.7	8.0	10.3	9.6	13.2	11.3	13.3	17.2	16.0	22.1
Cornwall, Ont.	Massena, NY	St. Lawrence Gas Co.	7.6	8.2	8.4	8.1	8.5	41.6	44.9	46.0	44.4	46.8
Ft. Frances, Ont.	Int'l. Falls, MN	Northern MN Utilities	3.5	4.2	4.3	5.0	7.2	38.2	46.0	47.2	54.8	79.0
Highwater, Quebec	North Troy, VT	Granite State	0.2	2.2	6.9	7.9	8.5			31.5	36.1	38.8
Phillipsburg, Quebec	Highgate Springs, VT	Vermont Gas Systems	5.2	5.8	6.3	6.6	7.1	31.7	35.3	38.4	40.2	43.3
St. Clair/Windsor, Ont.	Detroit, MN	MichCon, ANR	0.0	1.0	0.0	0.6	29.6	0.0				
	Grand Total (TCF per Year)		**0.989**	**1.268**	**1.338**	**1.435**	**1.680**	**55.8**	**72.0**	**74.6**	**77.7**	**84.7**

1.7 BCF/D by November 1992 completion date. Deliveries to be supplied by a pool of more than 300 Canadian producers.

- **Pacific Gas Transmission (PGT)** and/or **Altamont** – PGT expansion project (903 MMCF/D expansion) to California and Pacific Northwest currently underway, and/or the new Altamont pipeline would begin construction in 1994 of a 700 MMCF/D capacity line connecting Nova system to Kern River system at Opal, Wyoming, for redelivery to California and other markets.
- **Northwest Pipeline** – Expansion at Huntingdon, B.C./Sumas, Washington, by about 250 MMCF/D has begun. The new capacity will feed Pacific Northwest markets and serve as upstream capacity for some PGT expansion volumes to California.

The complete list of current projects could result in a total border crossing capacity of about 3.5 TCF per year by 1995—or an increase of around 75 percent over current levels (estimated at about 2.0 TCF at 100 percent load factor). By 1993, net Canadian imports are likely to rise to over 10 percent of the U.S. market share, and could account for up to 60 percent of total Canadian production.

Future export capacities assumed for this study are shown in Table 4-11.

Policy Considerations for Future Cross-Border Capacity

The current gas regulatory environment in Canada is one of substantially reduced political interference and a focus on the benefits of open markets and free trade. The basic principle of the NEB's "market based procedure" for gas export authorization is that free market forces should be allowed to operate and will ultimately determine what is best for Canadians. The Canadian government also remains committed to free trade with the United States and to all of the energy provisions contained in the U.S.-Canada Free Trade Agreement.

It is always difficult to speculate on future policy, but the demonstrated position of the Canadian government is a commitment to free and open trade in energy, and there is no evidence that this position will change in the coming years. Indeed, there is a clear recognition that trade restrictions would not be in the interest of the national economy in general, or the energy industry in particular. It therefore seems reasonable to expect that any future growth of Canadian gas export facilities, such as projected in this study, would receive timely approval from the Canadian authorities, and that the increased gas export volumes would not be subject to stricter regulatory constraints than exist today.

TABLE 4-11

FUTURE CANADIAN EXPORT CAPACITY TO THE UNITED STATES (BCF per Year at 90% Load Factor)

Import Pipeline	Border Crossing	1990	1995	2005	2015
Northwest Pipeline	Huntingdon	260	340	340	340
Pacific Gas Transmission	Kingsgate	535	845	845	1,010
Altamont	Wild Horse	–	235	235	235
Northern Border	Monchy	375	440	640	735
Great Lakes, Viking	Emerson	260	290	350	350
Tennessee	Niagara	100	250	250	270
	Other Northeast*	70	300	340	460
	Total	**1,600**	**2,700**	**3,000**	**3,400**

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* Includes deliveries to VT Power, St. Lawrence Gas Co., Granite State Gas Transmission, Champlain (if built), Iroquois Gas Transmission System, and Empire State (if built).

Mega/Frontier Projects — Constraints and Options

Projected Timing of Frontier Projects

Both the current modeling results and much conventional wisdom suggest that gas supplies from Canada's frontier areas and Alaska (which are currently not connected to the continental pipeline grid) will not be needed until the year 2000, if not later. Nonetheless, there have been numerous proposals for large-scale pipelines to connect these reserves to the Alberta market for redelivery into the existing North American pipeline network. Most of these proposals have revolved around the Alaska Natural Gas Transportation System (ANGTS), which would connect the gas reserves of the Alaska North Slope—the furthest from market of any of the identified "frontier" supplies in North America.

Segmented Development Approach

The ANGTS project (approved by the governments of both Canada and the United States) has yet to be constructed. However, one unique aspect of the project—the "pre-build" of the eastern and western legs—has allowed delivery of significant quantities of gas from the WCSB to markets in California and the U.S. Midwest since its completion in the early 1980s. Under the "pre-build" scheme new pipeline capacity was constructed in Alberta to feed new capacity to California utilizing a route involving Alberta Natural Gas/Foothills Pipe Lines (in British Columbia), Pacific Gas Transmission, Northwest Pipeline, and El Paso Natural Gas, and to feed a new pipeline system to the U.S. Midwest involving Foothills Pipe Lines (in Saskatchewan) and Northern Border Pipeline.

When it was authorized in 1977, the "pre-build" system was seen to have a number of significant benefits to the North American gas market:

- The "pre-build" facilities would allow additional exports of Canadian gas to U.S. markets at a time of surplus Canadian supplies and perceived shortages in the lower-48, until completion of the full ANGTS.
- The "pre-build" would encourage future exploration and development of WCSB reserves to fill the additional export capacity over the long term.
- Due to depreciation of the "pre-build" facilities over time, the transportation rates over the ANGTS (when completed) would be lower than they would be if the entire system was constructed at once.

Furthermore, the full ANGTS was perceived as an aid to the development of Canadian frontier supplies in the Mackenzie Delta area by providing a pipeline delivery system within 500 miles of those supplies. The existence of the ANGTS interconnecting with the North American grid in Alberta would require only the construction of the Dempster Lateral (which would interconnect with ANGTS near Whitehorse in the Canadian Yukon), rather than the construction of a completely new system (e.g., the Mackenzie Delta Gas Pipeline Project) all the way from the Mackenzie Delta to Alberta (via Norman Wells and Fort Simpson through the Mackenzie Valley). The development of these Canadian frontier reserves would benefit the entire North American market by providing additional supplies to market. (For further discussion on the selection of ANGTS in transporting Northern Alaskan gas into the North American grid system, refer to *Decision and Report to Congress on the Alaska Natural Gas Transportation System*, September 1977.)

Although the completion of ANGTS appears to be well into the future, several of the benefits of the "pre-build" facilities will likely remain valid in the expected North American gas market of moderate growth and sufficient supplies. By adding incremental capacity to deliver surplus and economic WCSB supplies to the U.S. markets, the "pre-build" has contributed to the efficiency of the continental market by providing access for the available supplies closest to the market—thereby avoiding the capital outlays necessary for the connection of more distant frontier supplies. The delay in connection of these frontier supplies has turned out to be fortuitous since the high delivered cost of these supplies (due in large part to the high transportation costs associated with any frontier project) would have made them uneconomic in today's marketplace.

These principles of incremental, rather than full-scale, attachment of new supplies could be applied over time to the balance of the unconnected North American gas supplies.

This policy would avoid the potential pitfalls of the all-at-once mega-projects. Specifically, this process would connect reserves in the following order, based on increasing distance from major markets:

1. Unconnected WCSB reserves in northern British Columbia.
2. Mackenzie Delta/Beaufort Sea supplies
3. Alaskan North Slope.

By taking this incremental approach, the North American market as a whole could attain the following benefits:

- The incremental attachment of new reserves would avoid the potential large price-dampening effects associated with the addition of larger volumes all at once.
- These frontier supplies would be attached earlier (but incrementally) because the capital requirements and financial risks of these incremental pipeline segments would be lower than for the all-at-once mega-projects.
- Incremental "pre-building" would provide lower transportation costs for the later-connected, more distant supplies, due to depreciation of the earlier segments.

This long-term approach would require close cooperation between U.S. and Canadian regulatory authorities and the pipeline companies involved. The entire system would need to be planned carefully with respect to timing, design, capacity, expandability, etc. This approach also necessarily implies the rejection of the ANGTS as currently approved and delays the delivery of Alaskan gas until after the connection of Canadian frontier supplies, which are closer to the markets.

History/Review of Proposals

There have been several proposals to deliver Canadian frontier and/or Alaskan supplies into the Alberta market for redelivery into Canadian and U.S. markets—two of these are shown in Figures 4-8 and 4-9. However, neither of those shown are expected to be completed soon. Recently the U.S. federal inspector of the ANGTS has proposed the repeal of that system's enabling legislation and the accompanying regulatory approvals in the United States and Canada in recognition of the current market realities of ample supplies and low prices. (*Report to the President on the Construction of the Alaska Natural Gas Transportation System*, January 14, 1992.) Even the sponsors of the new Mackenzie Delta project do not foresee completion of that system until at least the late 1990s or early 2000s.

Obstacles to Mega/Frontier Projects

Except for the "pre-build" sections of ANGTS, none of these frontier gas projects are even close to being constructed. While the plans may have looked attractive when they were proposed (generally during times of high energy demand and prices), they have all become uneconomic due to a variety of factors, including:

- Lower than expected gas demand as a result of conservation and the permanent loss of some industrial markets due to the high energy prices of the 1970s and early 1980s.
- Greater than expected growth in gas supply in the WCSB and the lower-48 due to improving technology and the supply stimulation of the high energy prices of the 1970s and early 1980s.
- Low projected wellhead netback prices for these frontier supplies due to high transportation costs and current low market prices for gas throughout the continent.
- Difficulties and risks involved in financing these very capital-intensive projects amid uncertainties in energy markets, demand, and prices.

Analysis

Model Discussion

The North American Regional Gas Model (described in Appendix C) was used early in the study to investigate several Canadian import sensitivity cases because the Energy and Environmental Analysis (EEA) Canadian module was not yet integrated into their North American model. Insights gained from the North American Regional Gas model analysis were used to guide the EEA analysis. However, once the EEA model was completed, results from it were used to quantify results presented in this study. Despite differences in modeling

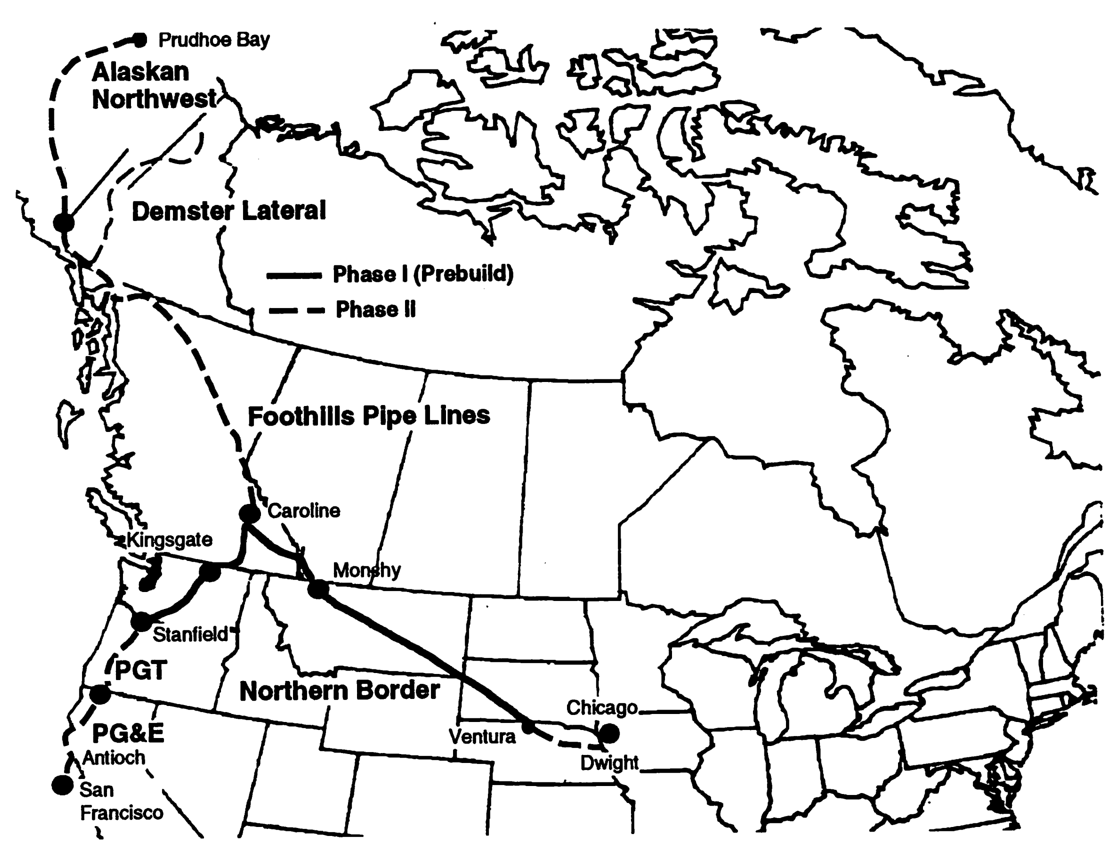

Figure 4-8. The Alaska Natural Gas Transportation System.

methodologies, several of the insights gained were common to both sets of results.

The EEA study on Canada integrated the Canadian natural gas sector in the Energy Overview Model including both Canadian and Alaskan supply regions into the Hydrocarbon Supply Model, expanded pipeline sectors to include the entire North American grid, and added Canadian and Alaskan gas demand sectors. Particular focus was given to the resource base in the WCSB and Frontier areas and to the North American transmission system.

The EEA model used was the fully integrated version including the Canadian module and new EEA gas pipeline detail. Canadian cash-flow constraints were also incorporated, as well as Canadian reinvestment ratios.

Study Assumptions

The two NPC Reference Cases were prepared by EEA: a moderate energy growth scenario (Case 1) and a low energy growth scenario (Case 2). In addition to these reference cases, two sensitivity cases were also investigated. Environmental impact factors used for Canada were considered the same as those used for the United States (1 percent per year starting in 1995). Technology advancement in Canada was also assumed to follow advancement in the United States, but it would lag the United States by two to three years. Demand growth assumptions for Reference Cases 1 and 2 were assumed to be the same in Canada as those assumed for the United States. Exports from the United States to Canada were held constant in all cases to 38 BCF per year.

The Aggressive Imports sensitivity case involved increasing the WCSB resource base estimate by 50 percent, with potential pipeline capacity doubling by 2010 and Mexican gas production increasing more quickly, leading to decreased purchases from the United States and a faster return of Mexican sales to the United States. The Canadian reinvestment ratio cap was increased from 75 to 80 percent.

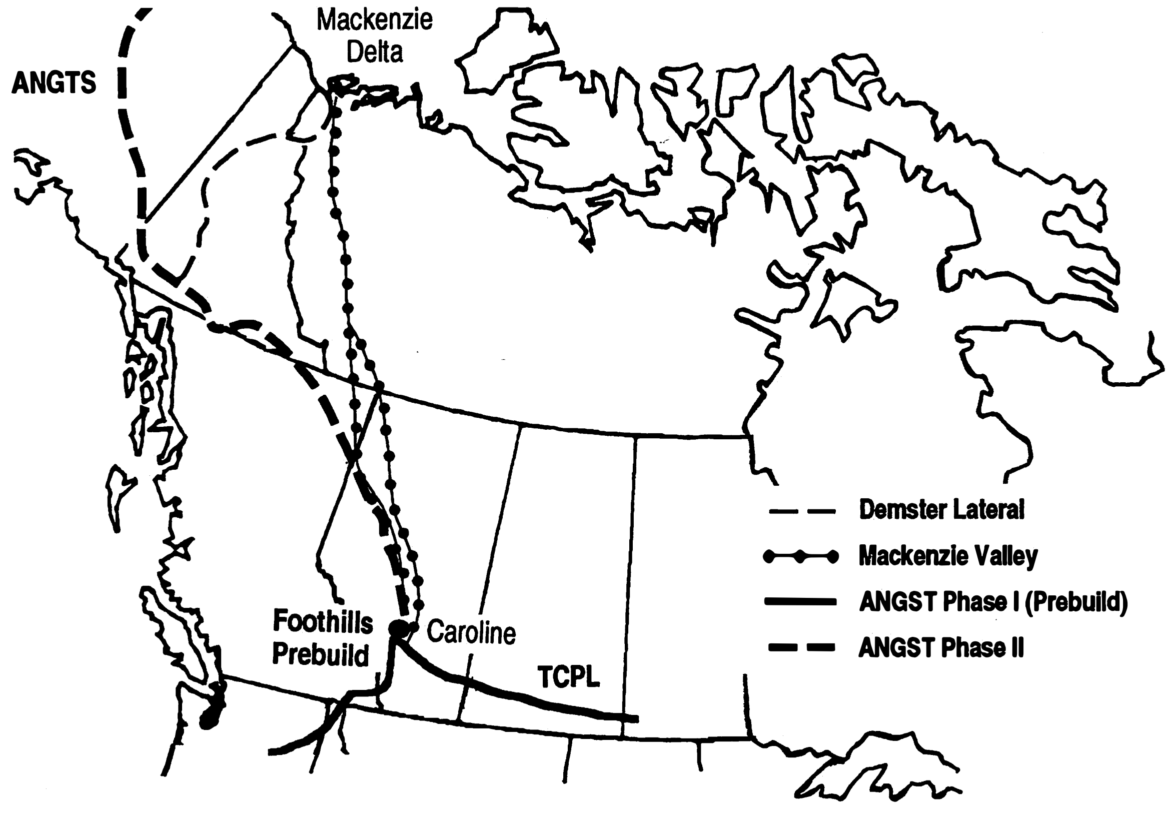

Figure 4-9. Mackenzie Delta Gas Transportation Systems.

The Restrained Imports sensitivity case restricted the maximum cross-border pipeline capacity to 2.1 TCF/year in 1995 and 2.4 TCF/year in 2010. (Base Case capacity was approximately 2.7 TCF/year in 1995 and 3.7 TCF/year in 2010.) Mexican demand for U.S. gas was higher in this sensitivity case and LNG imports were reduced to zero by 2010.

Case Results

Canadian Proved Reserves

Canadian proved reserves increased steadily in the early 1980s, reaching a high of 76 TCF in 1984. Reserves declined in the late 1980s as a result of reduced drilling activity, stabilizing at 70-71 TCF beginning in 1988. This trend of declining reserves continues through most of the 1990s as yearly reserve additions fail to offset produced volumes (Figure 4-10).

Reserves reach a low of less than 58 TCF in 1999 in Reference Case 2 (low growth) and grow slowly thereafter, stabilizing at 60 to 61 TCF by 2003. In the remaining three cases, reserves decline to 63 TCF by 1997, then rise steadily through 2010. In Reference Case 1 (moderate growth) and the Aggressive Imports Case, reserve growth averages more than 2 percent per year, reaching 82 TCF by 2010. Although reserve additions in the Aggressive Imports Case are higher than in Reference Case 1, production is also higher, resulting in nearly identical reserve growth. Reserves in the Restrained Imports Case grow to 76 TCF by 2010, an average increase of 1.5 percent per year.

Canadian Marketed Production

Historically, the province of Alberta has been the dominant natural gas producer, providing 84 percent of Canada's production in 1990. That same year, the other WCSB provinces of British Columbia and Saskatchewan contributed 11 percent and 4 percent, respectively. The remaining 1 percent is

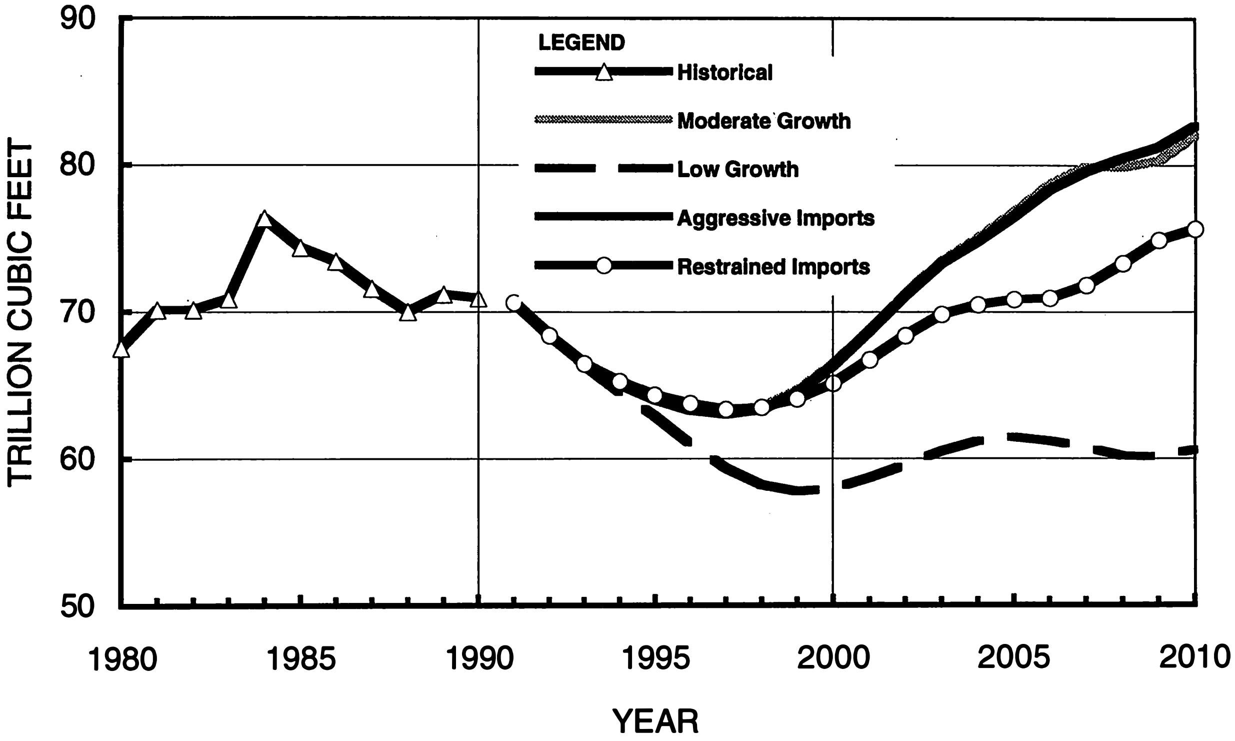

Figure 4-10. Canadian Proved Natural Gas Reserves.

supplied by Eastern Canada. This distribution of production is not expected to change significantly through 2010.

Marketed production in all cases grows at about the same rate until the late 1990s (Figure 4-11). Production in the moderate growth scenario increases 60 percent between 1990 and 2010, reaching 6.1 QBTU. As expected, production in the low growth scenario grows more slowly, totaling only 5.0 QBTU by 2010. Differences in Canadian domestic requirements between the Reference Cases account for nearly 60 percent of the 1.1 QBTU production variation, with exports to the United States comprising the remaining 0.44 QBTU. The sensitivity cases represent a 1.65 QBTU swing in marketed production, attributable solely to export volumes.

Canadian Domestic Natural Gas Sales

Canadian domestic natural gas sales reached 2 QBTU in 1989, and have remained at that level through 1991. In 1991, 44 percent of Canadian domestic sales were to industrial users, 24 percent to residential customers, 20 percent to commercial markets, and the remaining 12 percent for other uses (feedstock, electricity generation, transportation).

Domestic consumption increases to 2.4 QBTU in 2000 and 2.8 QBTU in 2010 in Reference Case 1, the moderate growth scenario (Figure 4-12). Sales to industrial customers grow about 50 percent faster than to all other customers (2.4 percent per year vs. 1.6 percent per year). Under Reference Case 2 ,the low growth scenario, industrial sales remain flat at 1991 levels, while sales to other customers increase by only 0.9 percent per year. Canadian domestic consumption under the low growth scenario totals 2.1 QBTU in 2000 and 2.2 QBTU in 2010. The import sensitivity cases, by definition, have no effect on Canadian domestic requirements.

Total U.S. Imports from Canada

From 1980 to 1988, approximately one-third of Canadian production was exported to the United States. Canadian exports of gas have been steadily increasing since that time as low-cost Canadian supplies compete aggressively in U.S. markets and new cross-border pipeline capacity allows increased flow to the lower-48 states. In 1991, exports to the United States rose to 46 percent of total Canadian

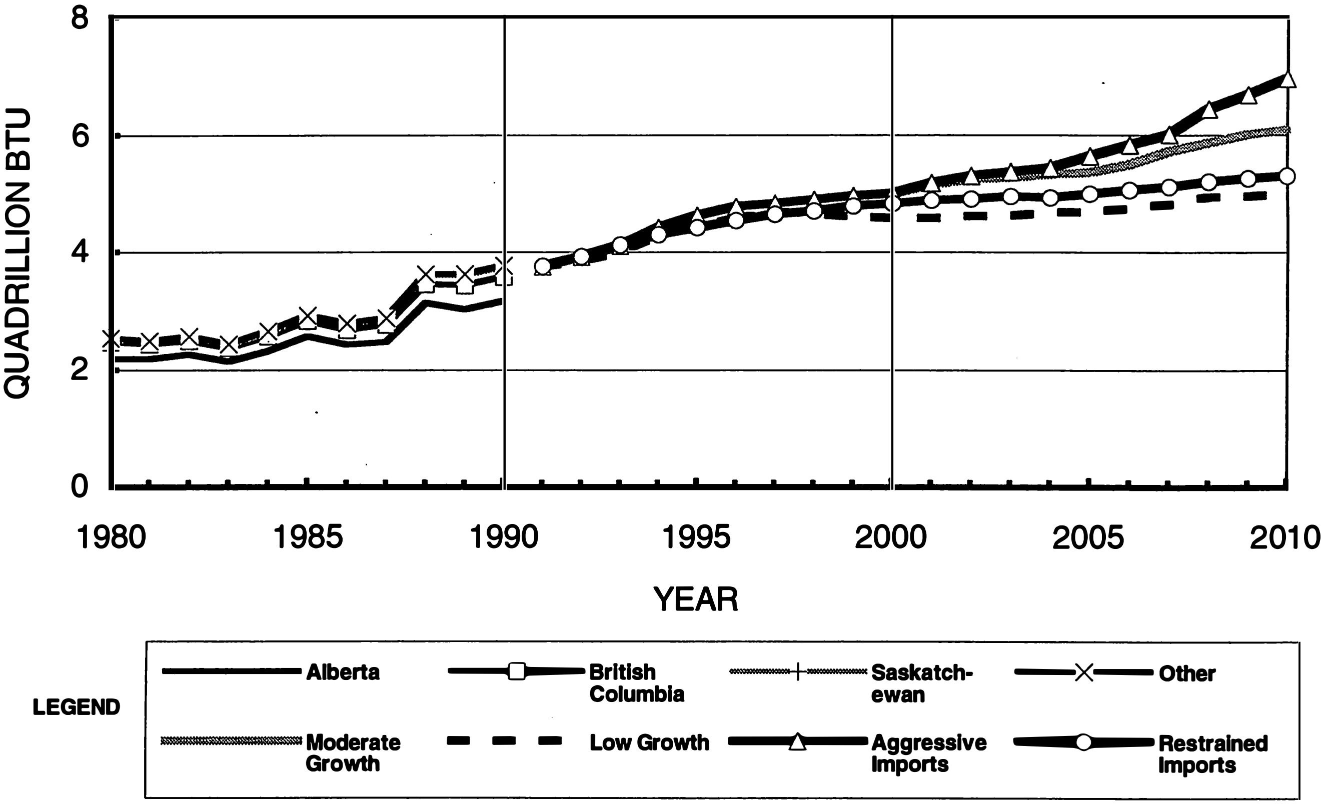

Figure 4-11. Canadian Marketed Gas Production.

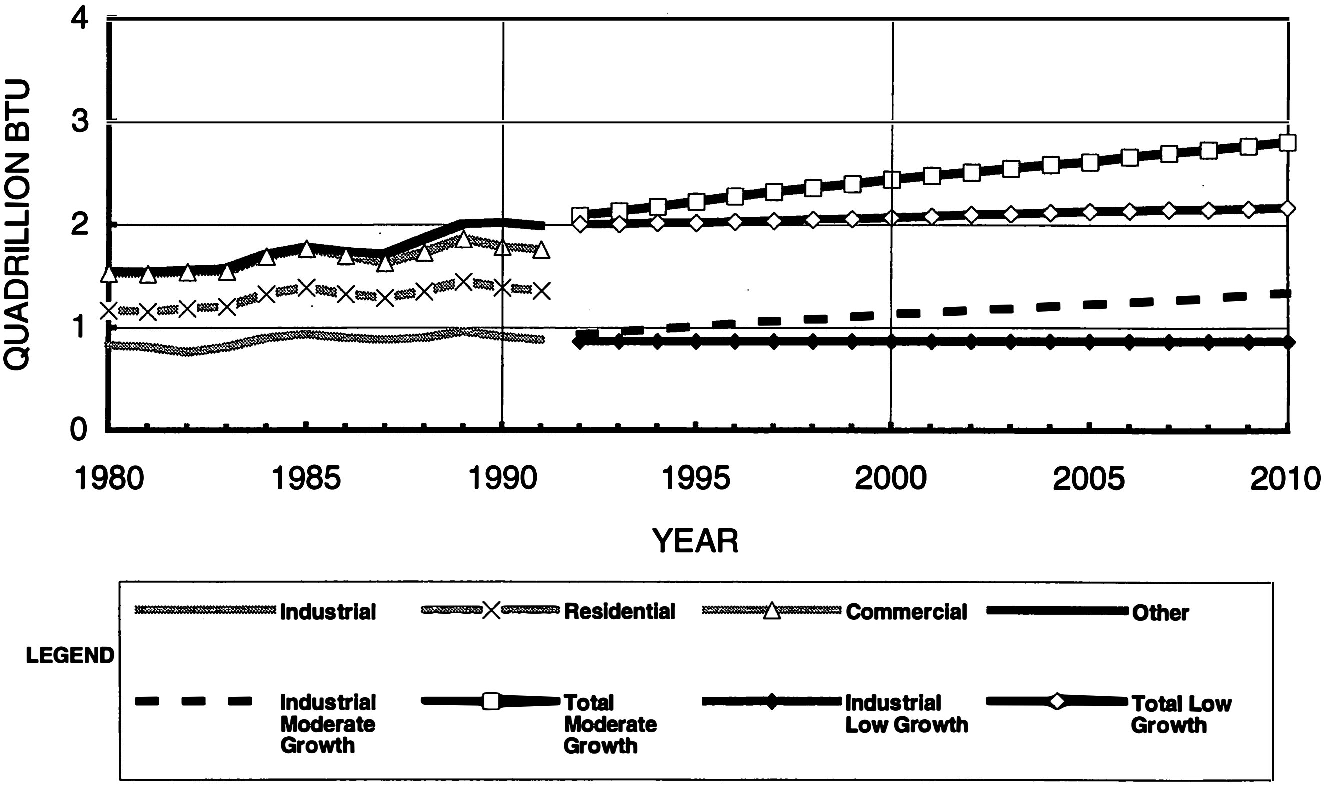

Figure 4-12. Canadian Domestic Natural Gas Sales.

production. In all four cases, import volumes and imports as a percentage of Canadian production increased from 1991 levels (Figure 4-13). Actual exports in 1992 should reach at least 2.0 TCF, even though results of the four cases indicate only 1.836 TCF.

The growth was most modest in the Restrained Imports Case, where import volumes rose to 2.4 QBTU by 2000 and to 2.5 QBTU by 2010. Imports as a percentage of Canadian production also increased slightly, rising to 50 percent in the late 1990s, then falling slowly to 47 percent by 2010.

In the remaining three cases, imports increased much more rapidly. As a percent of production, Reference Case 1 (moderate growth) and the Aggressive Imports Case tracked together through 1999; imports in the Aggressive Imports Case then began rapidly rising from 51 percent to nearly 60 percent of Canadian production by 2010. Through most of the study time period, imports in Reference Case 2 (where demand in the United States grows faster than in Canada) are the lowest in volume, but the highest as a percentage of Canadian production.

Empress, Alberta Prices

The average gas price at Empress, Alberta is shown in Figure 4-14. Empress acts as a "hub," aggregating Western Canadian supplies. In 1991, over 55 percent of the Canadian gas imported by the United States flowed through Empress; in the future, the proportion is expected to increase slightly, to 60-65 percent.

Reference Case 1 (moderate growth) and the Restrained Imports Cases yield the highest prices at Empress. The significantly higher volumes exported from Canada in the Aggressive Imports Case lower the U.S. average price of natural gas, and so the netback price at Empress is also lowered, to only slightly higher than Reference Case 2 (low growth).

Cross-Border Pipelines

Cross-border pipeline capacities and flows in 2000 and 2010 for each Reference Case are shown in Figures 4-15 through 4-18.

The pipelines into the U.S. Northeast (delivering at Niagara and Phillipsburg/Cornwall in the figures) showed the greatest growth. In

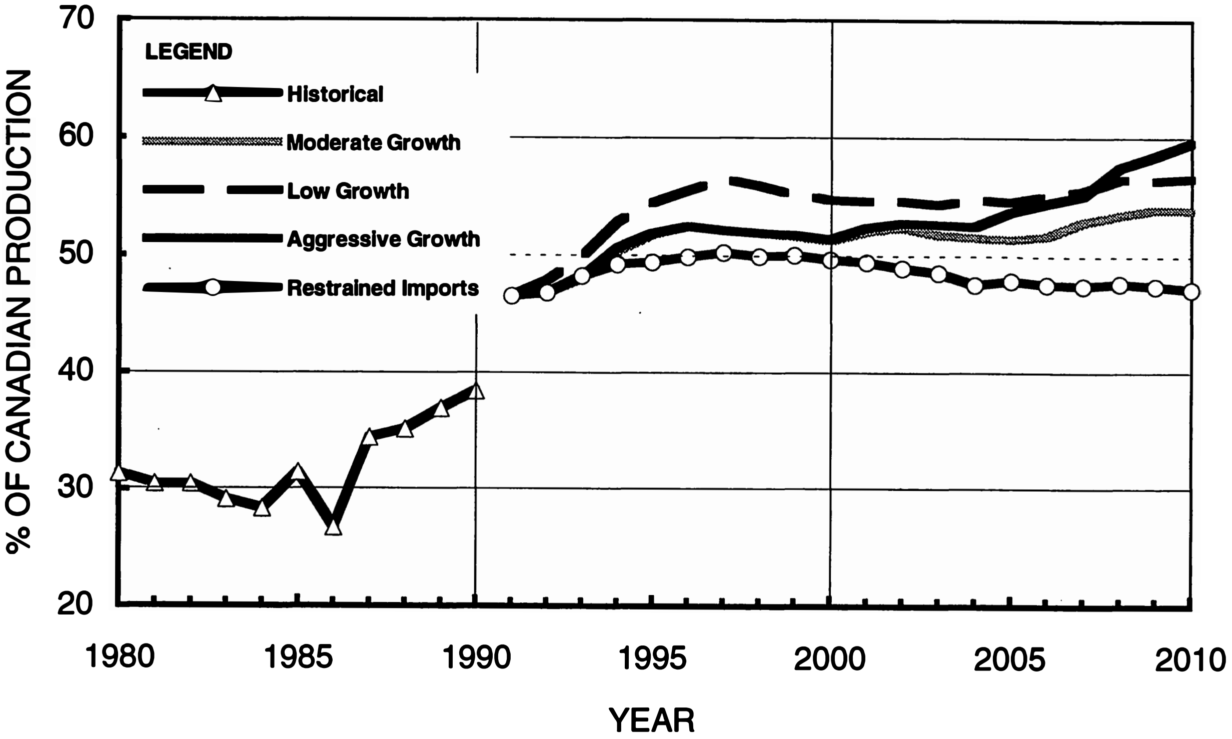

Figure 4-13. Total U.S. Imports from Canada

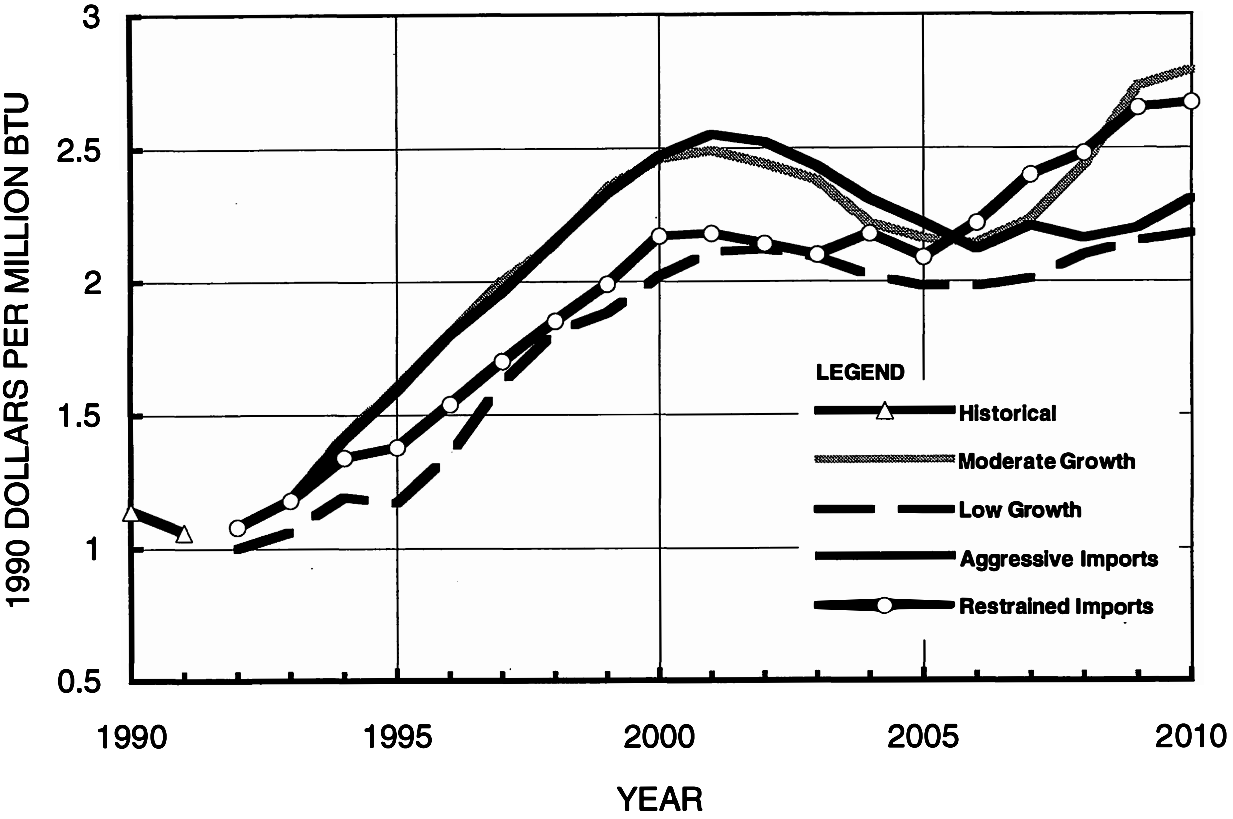

Figure 4-14. Natural Gas Prices at Empress, Alberta.

Reference Case 1 (moderate growth), pipeline capacity and flow increased nearly six-fold to over 2,100 MMCF/D of capacity and 1,900 MMCF/D of gas flow in 2010. Even in Reference Case 2 (low growth), capacity quadruples to 1,400 MMCF/D, with actual flow into Northeast markets reaching 1,200 MMCF/D by 2010.

Export capacity into the California market grows the least, increasing only 70 percent in Reference Case 1 and less than 40 percent in Reference Case 2. Utilization of the pipelines remained strong in both Reference Cases: 85-90 percent in the Case 1, and 75-80 percent in Case 2.

Conclusions

Canada's abundant natural gas resources will be capable of providing the lower-48 states with supplemental supplies well into the 21st century, recognizing that Canada's internal demand for natural gas will be met before volumes are made available for export. Production from Canadian Frontier areas will not be needed before 2010, since sufficient WCSB and lower-48 supplies are available to meet market demands at lower cost. Analysis of the sensitivity cases indicates that:

- Higher estimates of the Canadian resource base cause more Canadian gas to flow into U.S. lower-48 markets, reducing natural gas prices.
- Higher estimates of Canadian gas supply costs cause a reduction in Canadian exports to lower-48 markets, which are replaced by competitively priced Gulf of Mexico and Rocky Mountain supplies; a moderate increase in U.S. wellhead prices also results.
- Restrictions on cross-border capacity cause a "shortage" of Canadian gas into U.S. markets, resulting in higher U.S. gas prices, particularly in the Pacific Northwest and California.

In conclusion, future Canadian natural gas export trade will more likely be affected by economic conditions, including gas-on-gas competition in the United States, than by the level of proved reserves and potential resources in Canada. While the possibility of Canadian government intervention to constrain

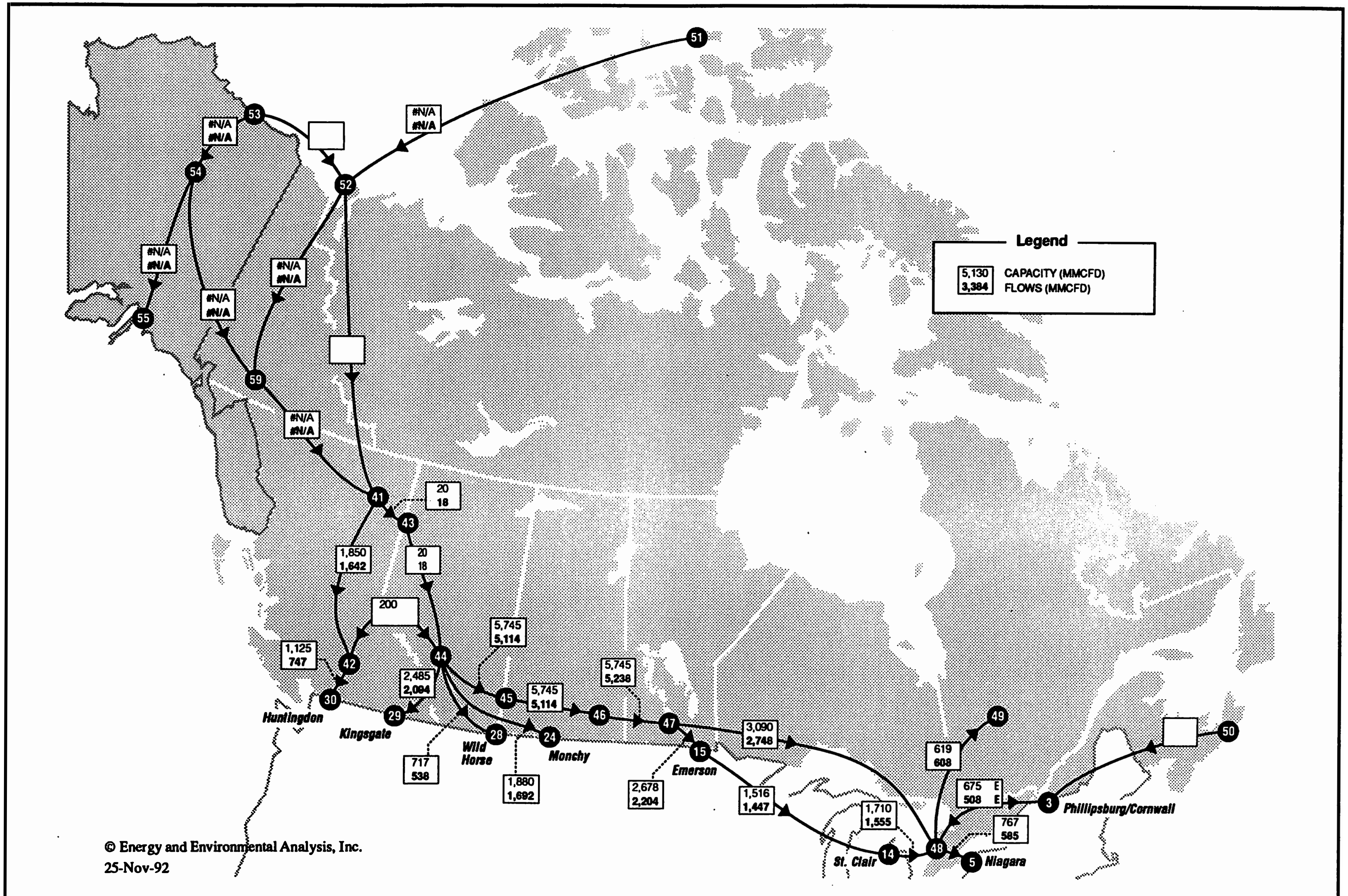

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Figure 4-15. Pipeline Capacity and Flows in 2000—Moderate Growth Scenario.

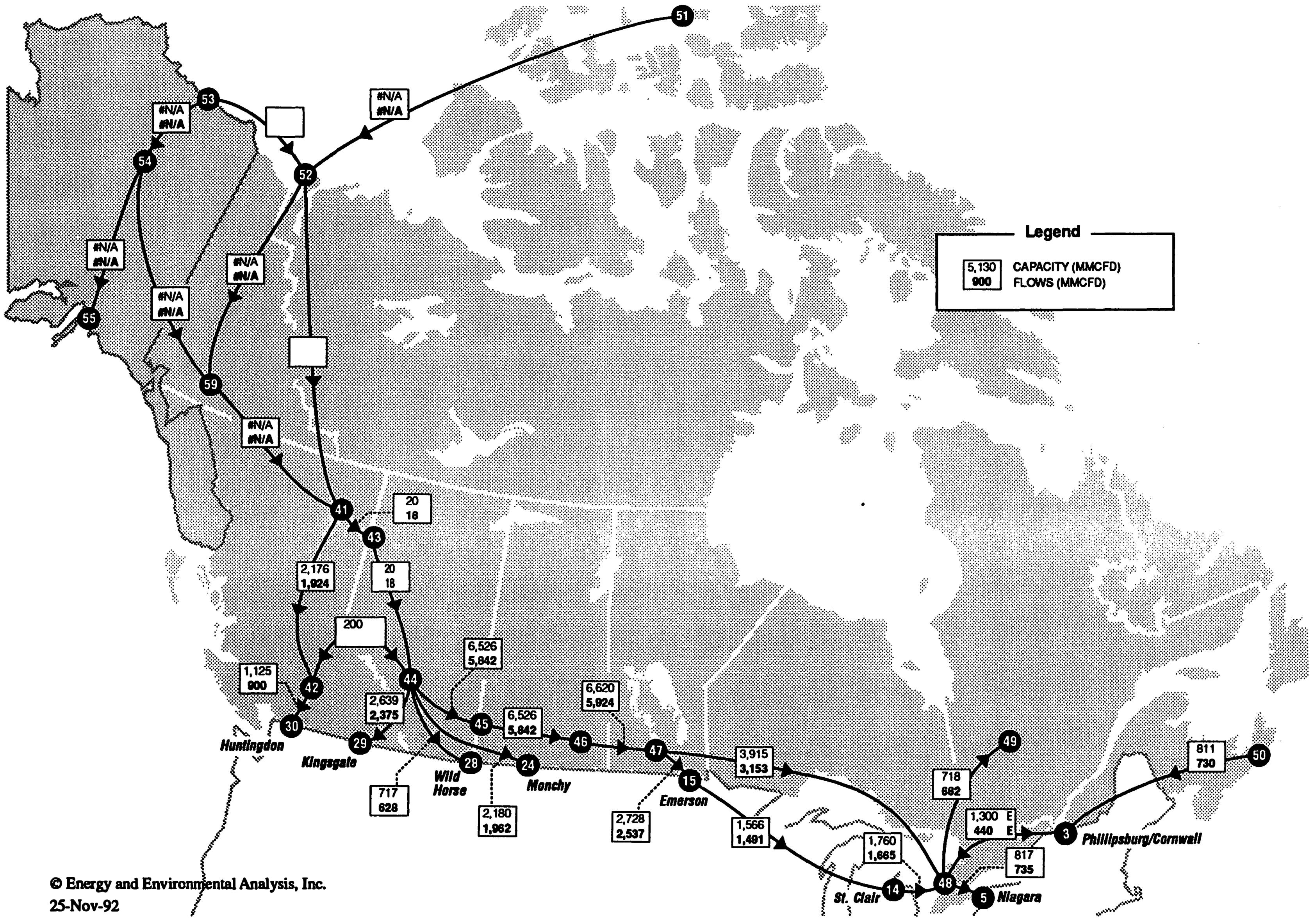

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Figure 4-16. Pipeline Capacity and Flows in 2010—Moderate Growth Scenario.

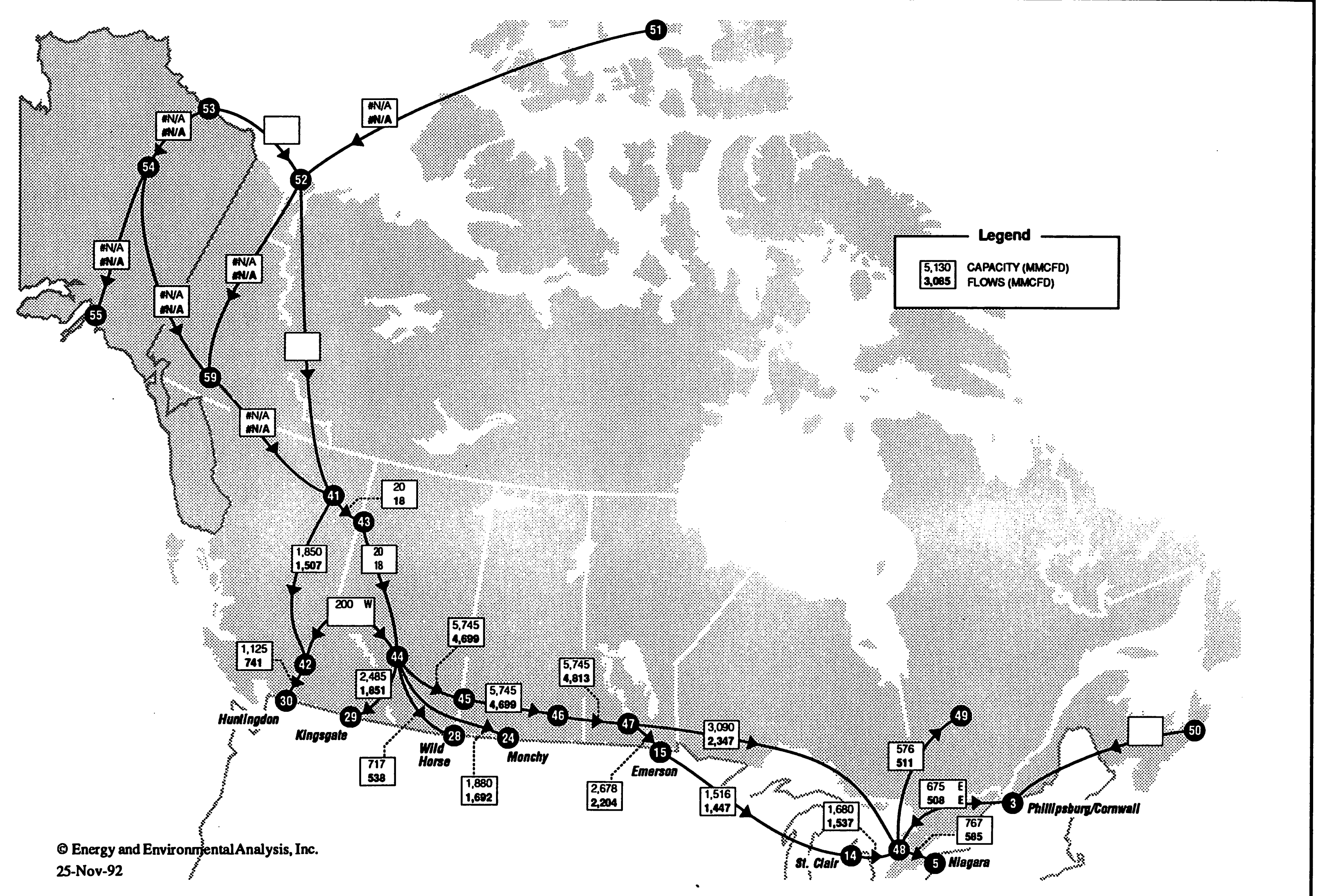

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Figure 4-17. Pipeline Capacity Flows in 2000—Low Growth Scenario.

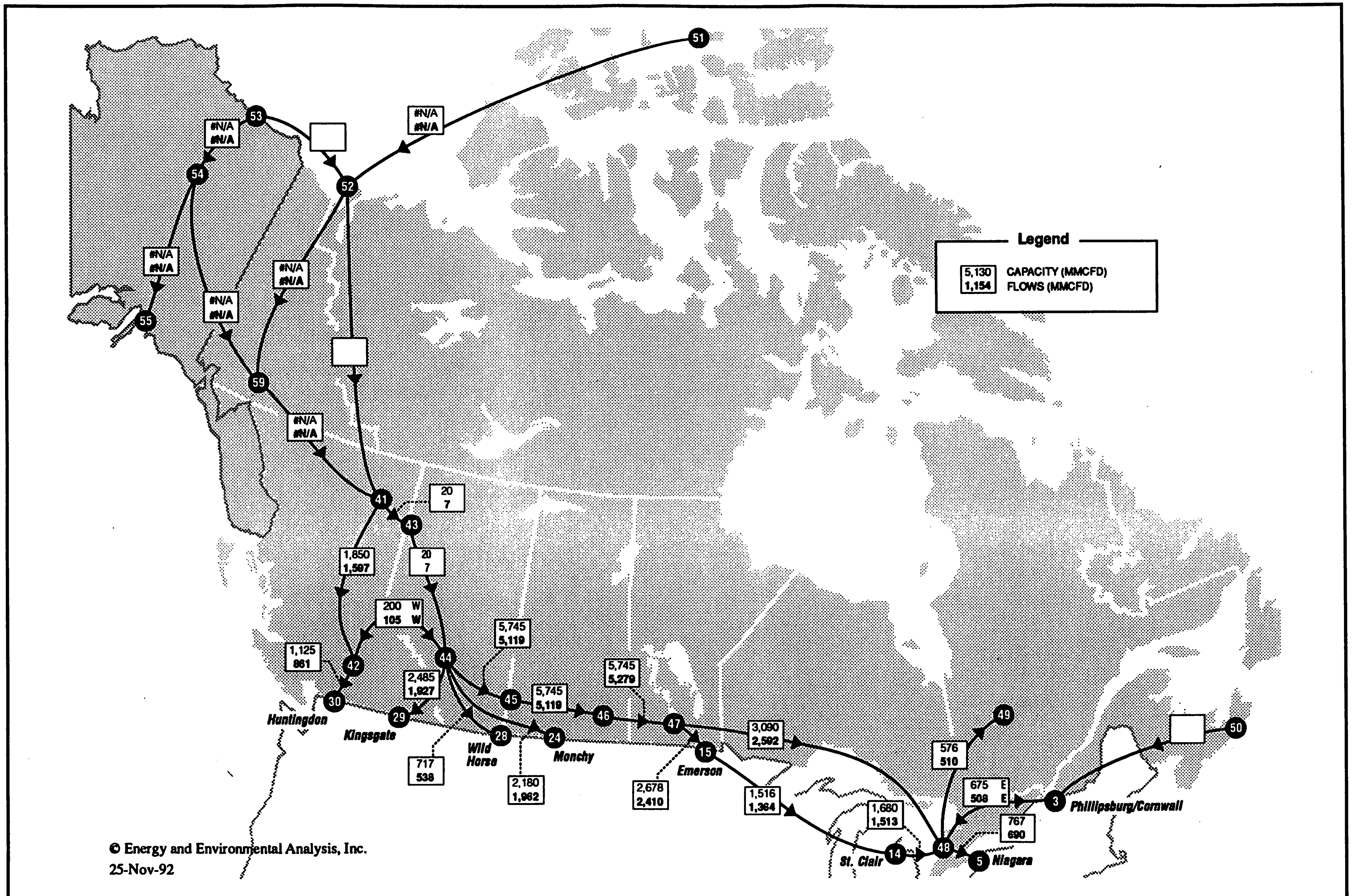

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Figure 4-18. Pipeline Capacity and Flows in 2010—Low Growth Scenario.

exports cannot be ruled out entirely, the energy provisions of the Free Trade Agreement and a philosophical commitment to free trade suggests that government actions pose only a remote threat to expanded gas trade by the Canadian industry. Moreover, the economic benefits of the gas trade to Canada—to government and industry—may tend to outweigh political concerns about exports.

MEXICO

Summary

Traditionally, most analyses of the North American gas market have focused on the supply and demand outlook for the United States and Canada. However, with continued market evolution, the North American gas industry is increasingly becoming a single, unified grid. As movement toward an integrated market progresses, the potential impact of the Mexican gas industry on the U.S. market must be assessed.

The current Mexican gas industry is essentially an associated by-product of the nation's oil industry. Petroleos Mexicanos (PEMEX), the state run oil company, has traditionally viewed oil as the principal income generator. As a result, virtually all of Mexico's gas is produced in association with oil. Due to this lack of focus on gas, Mexico's natural gas industry must be considered in its infancy relative to the industry of the United States or Canada.

Despite the historical emphasis on oil, Mexico has significant proved natural gas reserves and enormous undiscovered gas potential. Proved reserves are estimated at 71.5 TCF, roughly 40 percent of that of the U.S. lower-48 and equivalent to that of Canada's Western Sedimentary Basin. Industry estimates of Mexico's undiscovered potential are 180 TCF; however, it should be noted that there is some uncertainty in the magnitude of this potential due to the lack of drill hole data. All of this resource can be classified as conventional, and consists of both onshore as well as offshore reserves.

Current wet gas production is slightly over 1.3 TCF, down from a high of 1.5 TCF in the early 1980s. Although gas is produced from four major areas, 87 percent of Mexico's gas comes from the onshore and offshore basins in the Southern Isthmus Area. The Mexican pipeline infrastructure currently operates essentially at capacity. Pipeline capacity between the United States and Mexico is approximately 320 BCF per year, but several expansions have been proposed. This capacity can be used for either exports or imports.

Natural gas is presently receiving a renewed emphasis within Mexico's energy mix. Due to its environmental cleanliness, gas is replacing high sulfur fuel oil in both industrial as well as in power generation applications. PEMEX has adopted a strategy to selectively source the heavily polluted Mexico City area with indigenous gas supply. As a result, the large industrial centers in the north near Monterrey have increasingly been forced to turn to the United States for gas. This provides a market opportunity for U.S. gas producers and also provides some relief to Mexican end users who otherwise would have to pay much higher fuel prices.

Natural gas trade between the United States and Mexico has existed for over 40 years; however, the volumes have typically been minor. Between 1980 and 1984, the United States imported an average of 86 BCF per year under a contract between PEMEX and a consortium of U.S. pipelines. These imports were suspended in November 1984 following a decline in the U.S. and Canadian price indices that set the contract price for imported Mexican gas. PEMEX has stated that exports will not resume until the market price reaches $3.50/MCF (1991$). In the meantime, exports from the United States continue to expand, growing from 1 to 2 BCF per year in the mid-1980s to 60 BCF last year. The recent rise is due to PEMEX's inability to keep pace with the country's growing demand for natural gas as an environmentally clean fuel.

In the near to medium term, Mexico will represent an incremental market for U.S. gas. A severe lack of development capital will likely keep the country dependent on imports from the United States through the 1990s. Spurred by strong growth in both industrial and electricity demand, exports into northern Mexico are projected to increase from 60 BCF in 1991 to as much as 330 BCF (900 MMCF/D) by the turn of the century.

In the long term, Mexico has the potential to become a major supplier to the United

States. With its immense reserves in close proximity and already linked by pipeline to the United States, Mexico is truly a "sleeping giant" with regard to the U.S. market. The key to developing Mexico's gas potential and changing the country's position from being a net importer to that of a net exporter is the availability of capital for both gas development and expansion of the pipeline infrastructure. Currently, PEMEX does not have access to the necessary equity financing, either private or foreign, due to Constitutional law prohibiting foreign investment in the oil and gas industry. Given the present constraints on government spending coupled with the need to generate hard currency, private investment may be the only option to solve Mexico's gas future.

Introduction

Mexico is Latin America's largest producer of natural gas and the eighth largest gas producer in the world. Despite these statistics, most analyses of the North American gas market have focused solely on the supply picture in the United States and Western Canada. On the demand side, the emphasis has been on those end users serviced by the pipeline infrastructure within the lower-48 states and Canada. Traditionally, this market has consisted of a number of discrete demand regions, each governed by its own supply/demand balances and related pricing. However, with the advent of deregulation and the construction of new interstate and international pipeline capacity, these regional markets are becoming increasingly integrated into a single North American grid. As movement toward a unified gas market progresses, there is renewed interest in the future role of Mexico.

Mexico, which is already connected by pipeline to the greater U.S. gas market, is being affected by these changes in market dynamics. To date, the country has not been a significant factor in the North American market, but this could change dramatically in the future, *both* from a supply as well as a demand viewpoint.

Mexico is well situated to participate in expanded gas trade with the United States, either as an importer or exporter. Current domestic policy to selectively source indigenous gas production to the Mexico City area for environmental reasons has left the large industrial centers in northern Mexico with insufficient supply. Faced with a supply overhang, U.S. gas producers are keenly interested in being able to serve a growing Mexican market. Conversely, with over 250 TCF of proved and prospective gas resources, Mexico unquestionably has the potential to become a significant future supplier to the U.S. market. Whether this occurs or Mexico remains a demand center for U.S. gas will depend on several factors including the availability of development capital, Mexico's internal energy requirements, North American gas prices, and Mexico's export gas pricing policy.

Mexican Oil and Gas Industry

Oil and gas have been known in Mexico from surface seeps since before the Spanish conquest and colonization. Despite this long history, significant hydrocarbon production did not begin until after 1901. Mexico's abundant oil and gas resources were initially explored and developed by a number of independent and multinational companies. Production increased steadily such that by the early 1920s Mexico was second only to the United States.

This period of foreign development ended abruptly on March 18, 1938, with the government expropriation of all the holdings of 17 U.S. and British oil companies. The Partido Revolucionario Institucional, which has governed Mexico uninterrupted since 1929, established a state oil company, Petroleos Mexicanos, to oversee hydrocarbon development. To ensure the future control of the nation's hydrocarbon resources, a provision regarding ownership was added to the national Constitution. Article 27 specifically prohibits all foreign investment in oil and gas exploration and development infrastructure. Over the years, retention of this Article has become a prominent national issue.

The National Oil Company, PEMEX

Within the Mexican government, the Secretariat of Energy, Mines and State Industry is responsible for establishing general hydrocarbon policies. Its agent for carrying out government policy is Petroleos Mexicanos, or PEMEX. PEMEX has exclusive control over all aspects of Mexico's hydrocarbon industry including exploration, production, refining, oil distribution, sales, interstate gas transmission, and external trade. With assets of $45 billion and sales of nearly $9 billion, PEMEX is the single most important entity in Mexico's economy. Besides being the nation's largest employer, taxes on PEMEX sales and assets account for 30 percent of the government's annual revenue.

PEMEX is governed by an eleven-member Board of Directors: six appointed by the President and five appointed by the Petroleum Workers' Union. The Presidential appointees include the Secretaries of Energy, Housing, Planning & Budget, Commerce and Industrial Development, and Foreign Affairs, as well as the Director General of the Federal Electricity Commission. Structurally, PEMEX is divided into eight sub-directorates including Construction, Primary Production, Industrial Transformation, Sales, Finances, Administration, Planning, and Petrochemicals and Natural Gas. The Petrochemicals and Natural Gas sub-directorate was created in 1990 in direct response to PEMEX's increased emphasis on the role of natural gas.

Following the first international oil crisis of 1972-73, PEMEX began a large scale program of new drilling, mostly financed by foreign loans. Oil and gas production doubled over the next decade. However, when oil prices softened in the early 1980s, rising interest rates on the foreign loans resulted in a monumental debt crisis. The De la Madrid Administration (1982-88) made a decision to honor its foreign debt. As a result of these foreign debt payments, PEMEX has experienced a decade of decreased capitalization. With foreign equity investment prohibited under the Constitution, PEMEX must rely upon profits or new debt to finance exploration activity. Continuing low world oil prices have reduced profits, and only recently has PEMEX been in a position to take on a limited amount of new debt.

In light of these developments, the current Salinas Administration is beginning to pursue a strategy aimed at decentralizing PEMEX's main operations, which may lead to the privatization of some of the company's peripheral operations. This goal has already been accomplished in the area of retail gasoline sales. The gas liquids explosion disaster in Guadalajara (mid-1992) may further contribute to an overhaul of the state oil company. The degree to which PEMEX is ultimately restructured will determine the role Mexico will play in the North American gas industry over the next 20 years.

Current Energy Policy

Oil and gas industries are inexorably linked, but the linkage is even more pronounced in Mexico. Historically, oil has been perceived as the main income generator for PEMEX. As a result, domestic development capital is typically allocated for oil production and not for gas. Thus the increase in natural gas production over the past two decades has been in associated gas. In 1970, only 35 percent of Mexico's natural gas was associated with oil production. Today, virtually all of Mexico's gas production (85 to 90 percent) is associated. This policy of preferential oil production has served to retard the development of a separate gas industry.

Recent developments within the government may be changing Mexico's traditional outlook for gas. In its five year national plan for modernizing the energy sector (1990-94), the Ministry for Energy, Mines and State Industry has focused on increasing the importance of natural gas within Mexico. Elements of the new plan include:

- Modernize energy price structure by reducing hydrocarbon subsidies on domestic sales.
- Spread fiscal burden of development across all fuels by reducing some of oil's current preferential treatment.
- Target dry gas production at 3.3 to 3.4 BCF/D by 1994 (from about 3 BCF/D today).
- Establish an exploration and production program focused on natural gas.
- Increase use of natural gas in "environmentally high priority" activities such as electric power generation.
- Reduce PEMEX's fuel use of natural gas, especially within the petrochemical industry, thus making more gas available for the power generation sector.

Environmental Policy

One of the main factors spurring PEMEX's renewed interest in gas is the need to alleviate the country's significant air pollution problems. Since passage of the omnibus environmental law of 1988, the Salinas government has been actively engaged in improving Mexico's environment. For example, in 1991, government enforcement of pollution regulations closed more than 200 businesses for environmental violations. The most celebrated of these was the permanent closure of the Azcapotzalco Refinery in Mexico City.

Cornerstones of the drive to clean up the environment are the conversion of up to 450,000 vehicles in Mexico City to alternate fuels and the switching of all fossil fuel power plants from high sulfur fuel oil. Natural gas is projected as the fuel of choice in meeting both of these goals.

One of the more significant developments resulting from Mexico's environmental commitment has been the establishment of a "North-South" natural gas policy. The lack of development capital during the 1980s, coupled with increasing demand, has effectively eliminated a gas supply surplus within Mexico. Emphasizing gas use in the Mexico City area to reduce pollution has exacerbated the current supply imbalance situation. Most of Mexico's developed gas reserves lie in the Southern Isthmus Area. By focusing this indigenous production on the demand centers to the south, northern Mexican markets have increasingly been forced to turn to the United States for gas supplies. The situation is being viewed by the government as a near-term solution to the problem. The strategy avoids shifting scarce capital away from other economic activities. In addition, the "North-South" strategy benefits northern Mexico by providing low cost fuel (i.e., imports from the United States) to markets that otherwise would depend on more expensive gas transported long distances from the major producing areas in the south.

Supply

Natural Gas Resources

Mexico's proved natural gas reserves are currently estimated at 71.5 TCF (Table 4-12). This reserve base includes some 26.7 TCF of "undeveloped" reserves from the Chicontepec Basin. Chicontepec is located approximately halfway between the southern isthmus and the Texas border. Hydrocarbons from the basin are not considered economic at today's prices, nor are they expected to be so in the near future. This is due to the very low permeability (due to a high clay content) and high water content of the hydrocarbon bearing strata. By some estimates, over 10,000 new wells would be required to efficiently produce Chicontepec. For this reason, reserves from this basin are sometimes excluded from Mexico's "proved" category.

TABLE 4-12

MEXICAN NATURAL GAS RESOURCES AS OF DECEMBER 31, 1990 (Trillion Cubic Feet)

	Current Technology
Proved*	**71.5**
Conventional	
Reserve Appreciation	
New Fields	
Subtotal	**180.0**
Nonconventional	
Coalbed Methane	
Tight Gas	
Shale	
Subtotal	**‡**
Total Resources†	**251.5**

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* Reserve figures based on a number of estimates including those of PEMEX, *Oil & Gas Journal*, John S. Herold, the UCLA Consortium for Research on Mexico, the International Petroleum Encyclopedia, and others.

† Based on year-end 1990 data and includes the Chicontepec Basin within proved reserves. Preliminary 1991 estimates are 70.2 Proved, 180 Probable and Possible, 250.2 Total.

‡ Assessment not available.

All of Mexico's proved reserves can be classified as "conventional," contained within onshore as well as offshore discoveries. Further, 85 to 90 percent of the current proved reserves are associated gas. This compares to a comparable figure of 19 percent for the United States. The reason for this high percentage of associated gas is problematic. Mexican geologic sources cite a fundamental change in the oil-to-gas ratio relative to the U.S. Gulf Coast flexure trend. However, this ratio differential could be partially skewed by PEMEX's past focus on oil exploration and the fact that Mexico's full natural gas potential has yet to be found and developed.

Beyond the proved category, Mexico's undiscovered natural gas resource base has been variously estimated at about 180 TCF (Table 4-12). This estimate has been divided into 87 TCF as probable and 93 TCF as possible. No data on the speculative resource is generally available, although a few Mexican estimates have placed the total undiscovered resource base as high as 289 TCF (87 probable, 93 possible, 109 speculative). All of these estimates have a high degree of uncertainty due to the lack of drill hole data.

Based on current production rates, Mexico has a proved reserves-to-production ratio of about 54 years, as compared to approximately 10 years for the United States and about 20 years for Canada.

It should be noted that the substantial Mexican gas reserve base has been identified despite the lack of a concentrated effort to find or develop the resource. For example, in 1990 Mexico drilled just 17 new gas wells, compared to an estimated 7,170 in the United States (Figure 4-19). Thus the Mexican gas industry must still be considered in its infancy.

Gas Production and Deliverability

Current annual wet gas production is slightly over 1.3 TCF (3.6 BCF/D). Mexican gas production is only about one third that of Canada and significantly less than that of the United States (Figure 4-20). The low production total for Mexico relative to its North American neighbors again reflects the country's past emphasis on oil.

Due to Mexico's efforts to increase oil exports, natural gas production nearly doubled between 1970 and 1980, from 1.8 BCF/D to 3.5 BCF/D. Production peaked in 1982 at over 4.2 BCF/D. Since then, the lack of development capital due to Mexico's major debt crisis has resulted in declining production over much of the 1980s (Figure 4-21). While this trend has been partially reversed over the past two years, wet gas production is still nearly 600 MMCF/D below the 1982 level.

Offsetting the decline in production has been a concentrated effort by PEMEX to reduce the amount of flared gas. Mexican gas production capacity is directly linked to oil production capacity, which in turn is constrained by storage, refining and pipeline capacities. With higher oil production in the 1970s, co-production of associated gas increased above the capacity of PEMEX's gathering systems. As a result, the excess incremental gas had to be flared. In 1970, over 26 percent of Mexican gas production was flared. With recent increases in pipeline capacity spurred by an increased emphasis on gas as a valued product, only 2.9 percent of production was flared in 1990.

Mexican gas production comes principally from four regions. These include the onshore and offshore deposits in the Isthmus–Tabasco region, the Veracruz Embayment, the Tampico Embayment, and several basins along the Texas border collectively known as the Northeast Region (Figure 4-22). While all of these regions contribute to the national total, 87 percent of current production comes from the onshore and offshore basins in the south. Producing horizons range from Jurassic-Cretaceous limestones and sandstones in the south, to Miocene salt domes offshore, to Eocene-Oligocene sands in the Northeast.

Mexico's gas production is associated with the production of oil. Only gas in the Northeast region is largely non-associated. However, only 16 percent of Mexico's proved reserves are in the Northeast, primarily in the Burgos, Parras, and Sabinas basins. Due to their location, development of these reserves will be key in affecting the country's import/export strategy. Traditionally, the geologic model for the northeastern basins has been the U.S. Overthrust Belt. However, recent drilling designed to test this model has failed to yield predicted discoveries. As a result, some analysts project that Mexico may never be able to supply its own demand requirements, let alone become a net exporter to the United States. Others suggest that the wrong geologic model has been employed and that deeper drilling will reveal complex but profitable traps. Analogous areas across the border in Texas have shown that gas is present in highly faulted and fractured traps that can be exceedingly difficult to discover.

Gas Processing

Mexico's gas is essentially sour, containing significant amounts of both hydrogen sulfide and

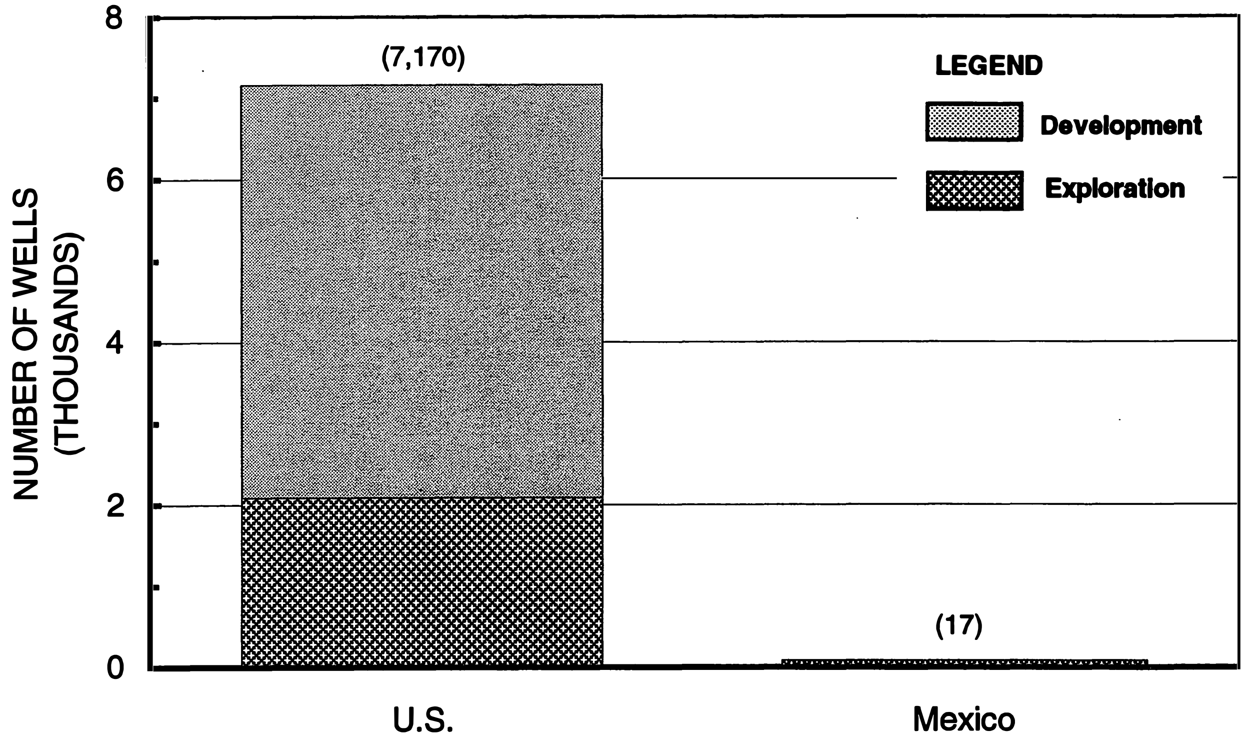


Figure 4-19. 1990 Total Gas Wells Drilled—U.S. vs. Mexico.

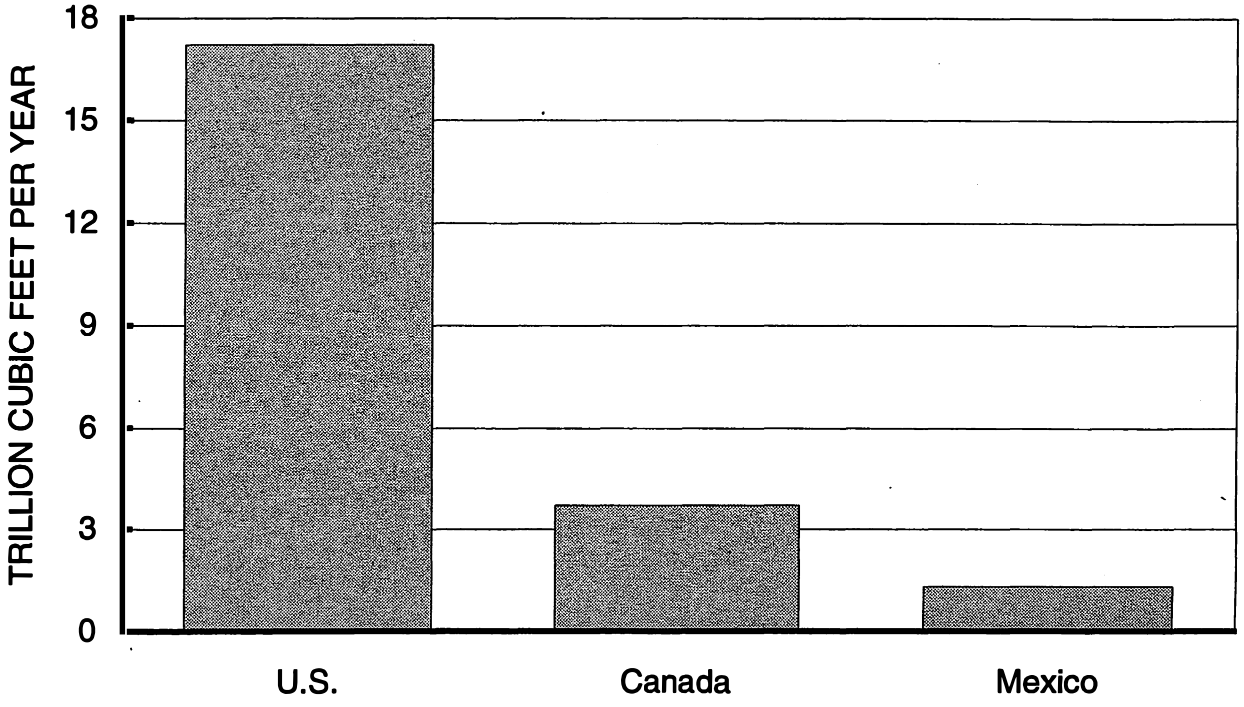


Figure 4-20. 1990 Natural Gas Production—U.S., Canada, and Mexico.

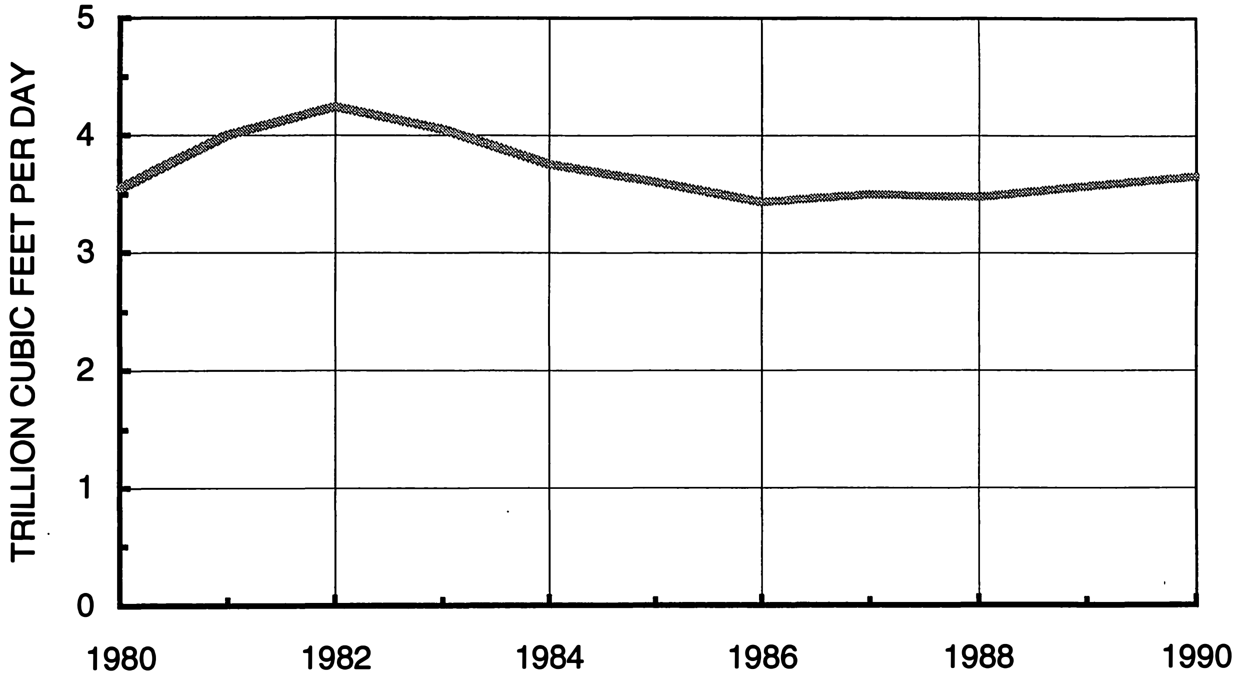
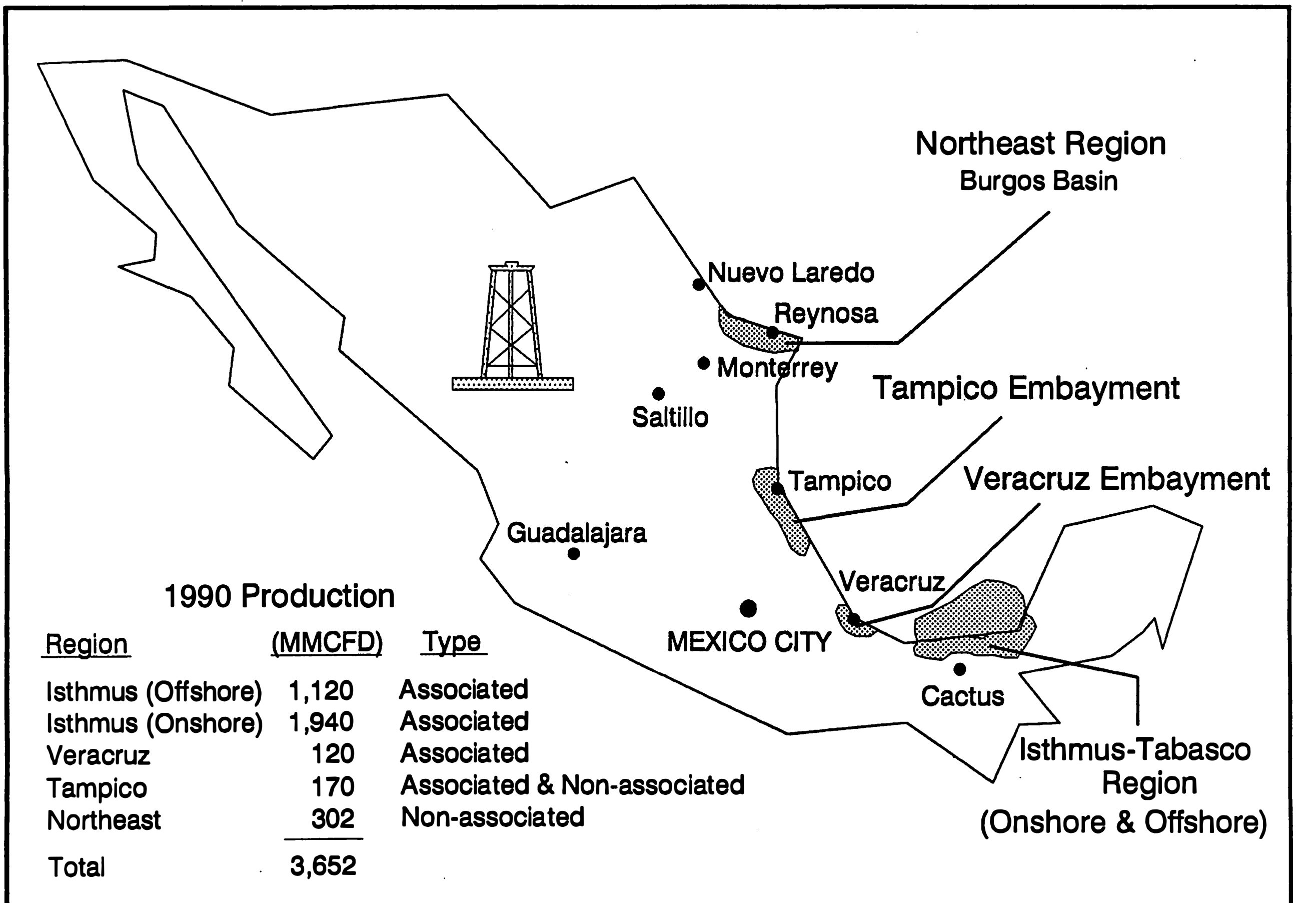


Figure 4-21. Mexican Gas Production—1980 to 1990.



1990 Production

Region	(MMCFD)	Type
Isthmus (Offshore)	1,120	Associated
Isthmus (Onshore)	1,940	Associated
Veracruz	120	Associated
Tampico	170	Associated & Non-associated
Northeast	302	Non-associated
Total	3,652	

Figure 4-22. Natural Gas Producing Areas of Mexico.

carbon dioxide. All production except some non-associated gas in the Northeast must be treated before it is transported and consumed.

Mexico has a total of 15 gas processing plants, all owned and operated by PEMEX. Five of these (Cactus, Ciudad PEMEX, Matapionche, Nuevo PEMEX, and Poza Rica) are gas sweetening plants used to remove the high concentrations of hydrogen sulfide and carbon dioxide. Total capacity of these plants is nearly 3.8 BCF/D, consistent with current wet gas production (Table 4-13). In addition, PEMEX also operates eight cryogenic and three absorption plants, which are mainly dedicated to extracting ethane and heavier hydrocarbons.

Transportation

Mexico has a well-developed gas transportation system, which includes 101 separate pipelines with a total length of 13,166 kilometers (8,163 miles) (Figure 4-23). The major arteries are a southern system from Ciudad PEMEX to Guadalajara, a national trunkline from Cactus to Monterrey, and a northern system that moves gas north and west of Monterrey.

The southern system consists of two 24-inch, a 48-inch, and a 30-inch diameter line. The system connects the major reserves in the Isthmus and Veracruz areas to the major demand centers in Mexico City and Guadalajara.

The northern system links the basins in the Northeast to the industrial centers in the Monterrey-Monclova area. Westward capacity of the system is on the order of 325 MMCF/D. The system also provides access for the national trunkline to the U.S. border.

The national trunkline consists of a 48-inch diameter pipeline constructed at a time when Mexico was exporting gas on a regular basis to the United States (1980-1984). The final Monterrey to Reynosa leg of the trunkline was never expanded from the existing 22-inch diameter configuration, although the pipe was purchased and is reportedly still in storage. Cost of completing the 48-inch diameter line to the border is projected to be $50 million. The transportation rate from Cactus to the border (900 miles) is estimated at $1.05/MMBTU (1992$).

Currently there are four cross-border links between the United States and Mexico (Figure 4-23 and Table 4-14). The most important of these is the Texas Eastern connection at McAllen, Texas. Transportation across the border is controlled by Border Gas, a consortium owned jointly by Tenneco (37.5 percent), Texas Eastern (27.5 percent), El Paso (15 percent), Transco (10 percent), SONAT (6.7 percent), and Florida Gas (3.3 percent). Cross-border capacity is about 350 MMCF/D but could be expanded to 1 BCF/D with compression.

TABLE 4-13

PEMEX NATURAL GAS PROCESSING FACILITIES' CAPACITY
(Million Cubic Feet per Day)

Processing Facility	Sweetener Plants	Cryogenic Plants	Absorption Plants
Cactus	1,800	1,450	—
Ciudad PEMEX	800	200	550
La Congrejera	—	30	—
La Venta	—	182	200
Matapionche	60	150*	—
Nuevo PEMEX	800	500	—
Pajaritos	—	192	—
Poza Rica	300	275	—
Reynosa	—	—	500
Total	**3,760**	**2,979**	**1,250**

* Under construction.

Memo: 1990 Production was 3,652 MMCF/D.

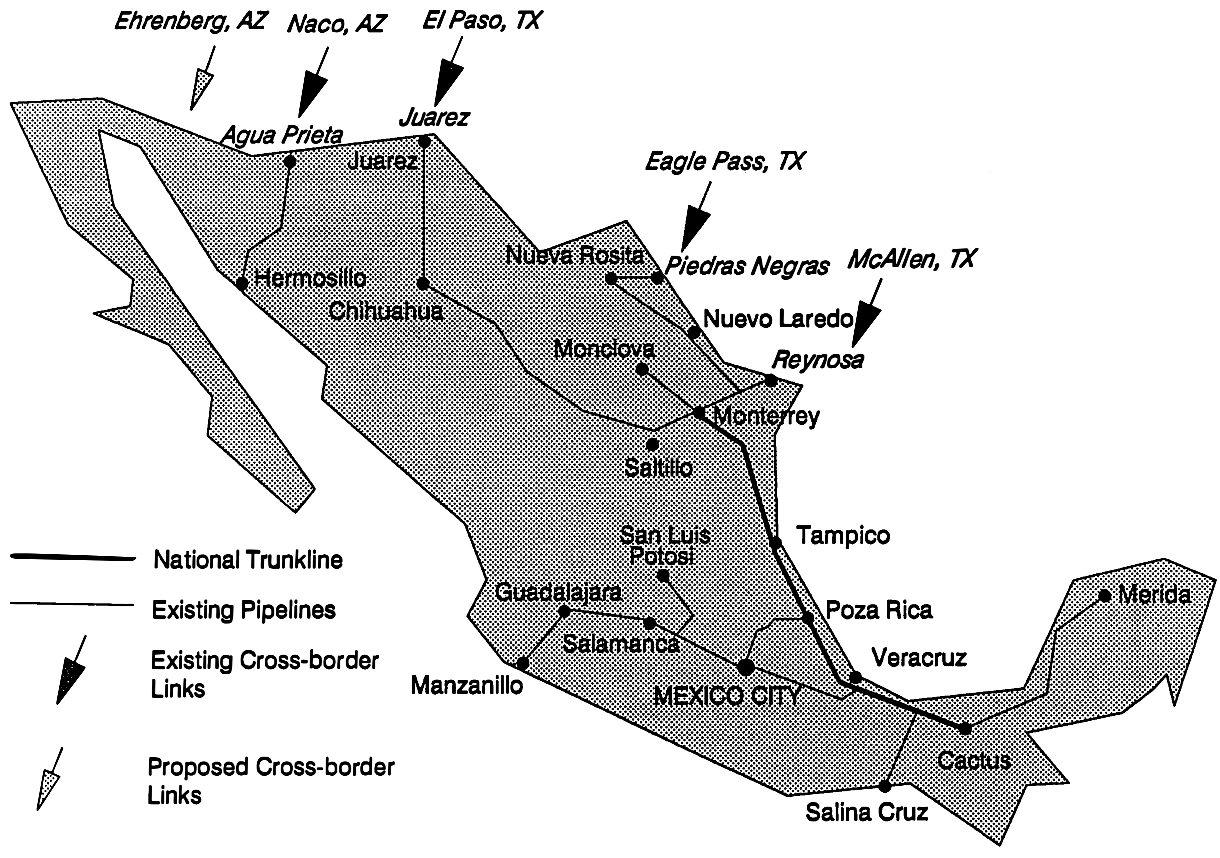


Figure 4-23. Mexican Natural Gas Pipeline Grid.

El Paso Pipeline Company owns a 35 MMCF/D connection linking Naco, Arizona to the Agua Prieta, Mexico area. This line can only be used for imports of gas from the United States, since the line on the Mexican side of the border is not connected to Mexico's main pipeline systems or reserves. Western Gas Interstate controls several small cross-border points near El Paso, Texas. The connections serve the foreign dominated, light manufacturing *maquiladora* factories along the border. The last interconnect is owned by Valero Transmission. The 4 MMCF/D system links Eagle Pass, Texas, to Piedras Negras and is only used for imports from the United States to local Mexican factories.

Valero Transmission completed an expansion into Mexico with a capacity of 400 MMCF/D in August 1992. This interconnect is located at Hidalgo, about 15 miles west of Texas Eastern's Border Gas interconnect, and has an initial capacity of 200 MMCF/D.

Four new major cross-border links have recently been proposed (Table 4-14). A Reynosa cross-border interconnect has been proposed by Houston Pipeline. Although planned for 1993, it is unclear whether this 600 MMCF/D capacity link will be built since the Valero line has been completed.

Another pipeline is proposed by Tri-National Power, a consortium of Community Energy Alternatives, Intercon Gas, NOVA Corporation, and two Mexican firms. The pipeline would link El Paso's southern line at Ehrenburg, Arizona, to the Rosarito power plant near Tijuana. Gas transported on this system would be used to replace high sulfur fuel oil at a repowered generating unit. A number of pipeline projects have been proposed that would provide U.S. gas supply to the Rosarito plant. The Tri-National Project is used here as a surrogate for all of the proposed projects.

El Paso Natural Gas has proposed a 100-130 MMCF/D interconnect to PEMEX's system across from El Paso, Texas. The line would be dependent on a second gas-fired expansion at the Comision Federal de Electricidad's Samalayuca power plant.

TABLE 4-14

CURRENT AND PROPOSED U.S.–MEXICO CROSS-BORDER LINKS

Current

Existing Import/ Export Point	Pipeline	Capacity (MMCF/D)	Estimated Current Load (MMCF/D)
Naco, Arizona	El Paso Natural Gas	35	15
El Paso, Texas	Western Gas Interstate	90	30
Eagle Pass, Texas	Valero Transmission	4	2
McAllen, Texas (Hidalgo)	Texas Eastern (Border Gas)	350	118*
McAllen, Texas (Hidalgo)	Valero Transmission	400	200
		879	365

Proposed

Cross-Border Point	Pipeline	Capacity (MMCF/D)	In-Service Date
McAllen, Texas	Houston Pipeline	600	1993
Ehrenburg, Arizona†	Tri-National Power (NOVA)	350	1994
El Paso, Texas	El Paso Natural Gas	100-130	Indefinite
Laredo, Texas	ENSA	500	Indefinite

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* Estimated average for full 12-month period of 1991. During last four months of 1991, load was 250-300 MMCF/D.

† Numerous proposals exist for this proposed cross-border point. Tri-National is shown as the original proposal.

The last proposed cross-border pipeline is a 250-foot line connecting intrastate Texas pipelines near Laredo to a yet-to-be-built Mexican link from Monterrey to Nuevo Laredo. Lack of development capital on the Mexican side coupled with the new proposed Valero line appears to have pre-empted this project, which has been indefinitely deferred.

Demand

Total primary energy requirements in Mexico were 5.2 QBTU in 1990. Of this, 55 percent was supplied by oil while natural gas provided 29 percent of the country's needs (Figure 4-24). Gas's share has risen dramatically over the past several years largely in response to environmental requirements. Mexico's remaining energy needs are satisfied by hydropower (5 percent), coal (3 percent), biomass (7 percent), and nuclear and other sources (1 percent).

Gas consumption within Mexico is markedly different from that in the United States. In the United States, residential/commercial use comprises nearly 40 percent of demand, while petrochemical (both feedstock and process) use accounts for less than 10 percent of total demand. In Mexico, petrochemicals consume 35 percent of demand, while residential heating use is relatively insignificant (Figure 4-25).

The largest single consumer of gas is PEMEX, which uses it in the production of ammonia and petrochemicals. About 80 percent of Mexico's petrochemical industry uses natural gas as a feedstock. The dominance of the petrochemical sector in gas consumption has resulted in a large amount of high sulfur fuel oil use in other industrial applications and for power generation. This traditional pattern of end use is slowly changing as environmental pressures are mounting for industries to substitute cleaner burning natural gas for fuel oil.

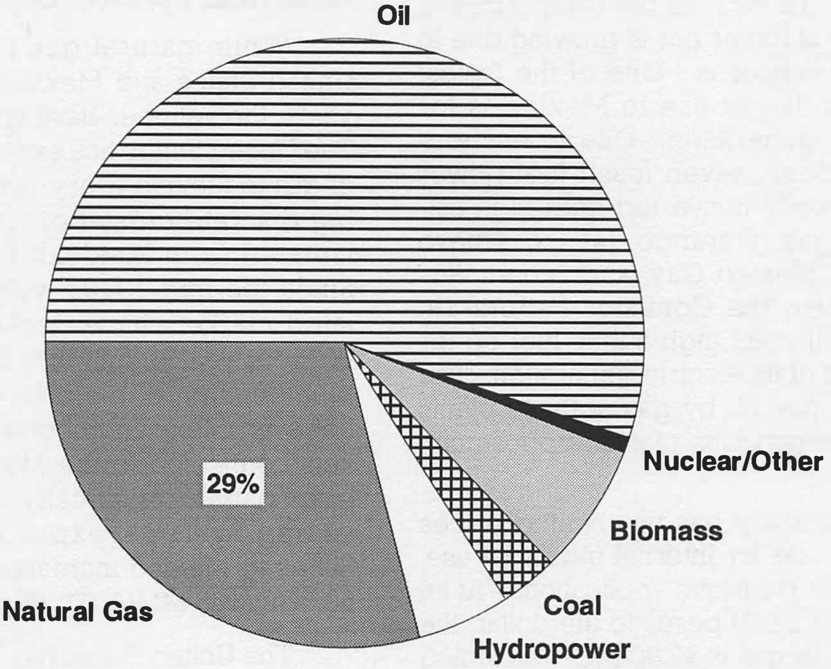

Figure 4-24. 1990 Mexico Energy Mix (5.2 Quadrillion BTU).

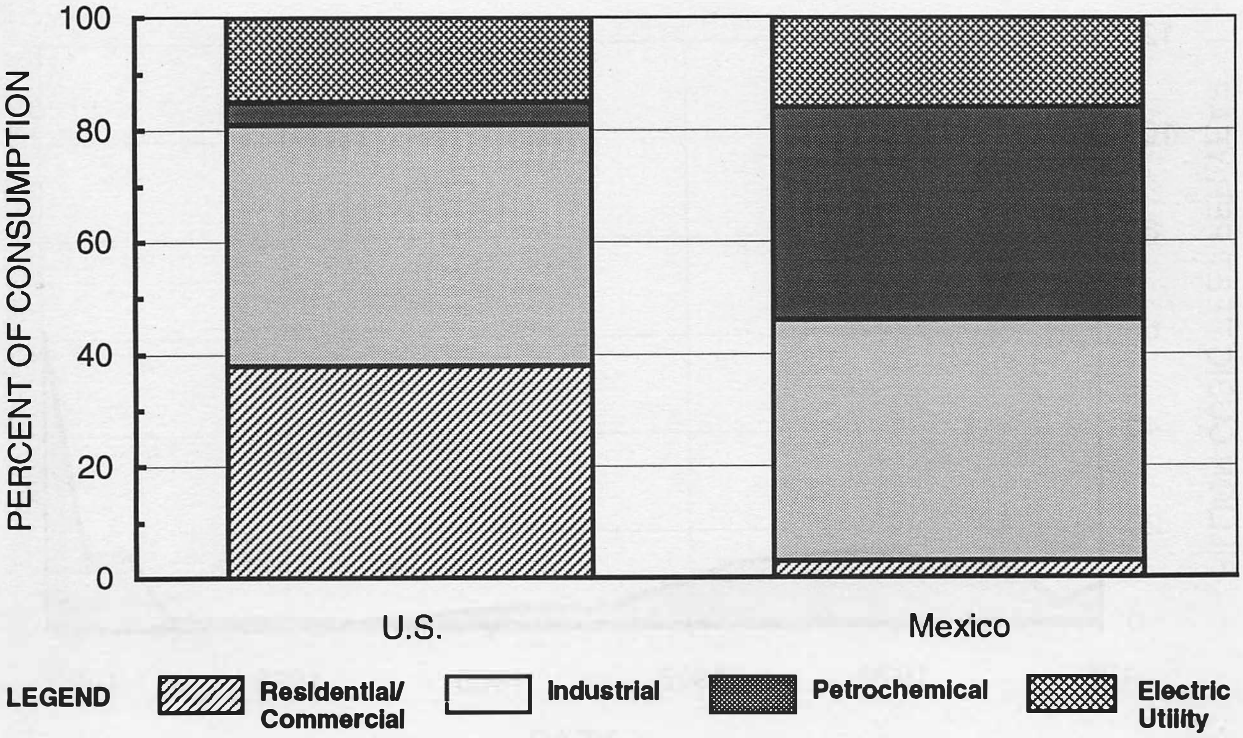

Figure 4-25. 1990 Natural Gas End Use by Sector—U.S. vs. Mexico.

The majority of salable gas not used in the production of petrochemicals is sold to process industrials such as the glass industry. Residential use is minor but is growing due to environmental concerns. One of the fastest growing areas of gas use in Mexico is for electric power generation. Due to environmental regulations, seven fossil fuel power plants have recently converted from high sulfur fuel oil to gas (Durango, Jalisco, Nuevo Leon, Hidalgo, Mexico City, and two at Veracruz). However, the Comision Federal de Electricidad still uses high sulfur fuel oil for over 60 percent of its electric generation. The replacement of fuel oil by gas at these plants represents a tremendous market opportunity for the future.

PEMEX currently has two selling prices for natural gas, one for internal industrial use, and one for other domestic applications. At an exchange rate of 3,060 pesos to the dollar, the price for industrial gas is $2.80/MCF (including tax). The price for the domestic market is $2.27/MCF (including tax). Given these prices plus the high transportation cost of moving southern gas to the north, it is readily apparent why U.S. gas is attractive to northern Mexico end users.

Import/Export Markets

Historical Mexico/U.S. Gas Trade

While natural gas trade between the United States and Mexico has existed for 43 years, the volumes have typically been minor. The United States has exported small volumes of gas to Mexico every year since 1949, serving discrete cross-border markets that are isolated from Mexican indigenous supply. Since the mid-1970s, volumes to these isolated markets have declined from 10 to 15 BCF per year to only 1 to 2 BCF. With the implementation of the "North-South" strategy, however, Mexican imports of U.S. gas to markets connected to the Mexican national grid have risen dramatically over the last three years. By 1991, exports from the United States to Mexico increased to approximately 60 BCF (165 MMCF/D) (Figure 4-26).

The United States has imported small volumes of gas from Mexico periodically since 1952. Imports averaged 40 BCF per year from 1957 to 1971, but virtually disappeared between 1972 and 1979. Imports resumed in 1980 with an agreement between PEMEX and Border Gas. The contract provided for sales up

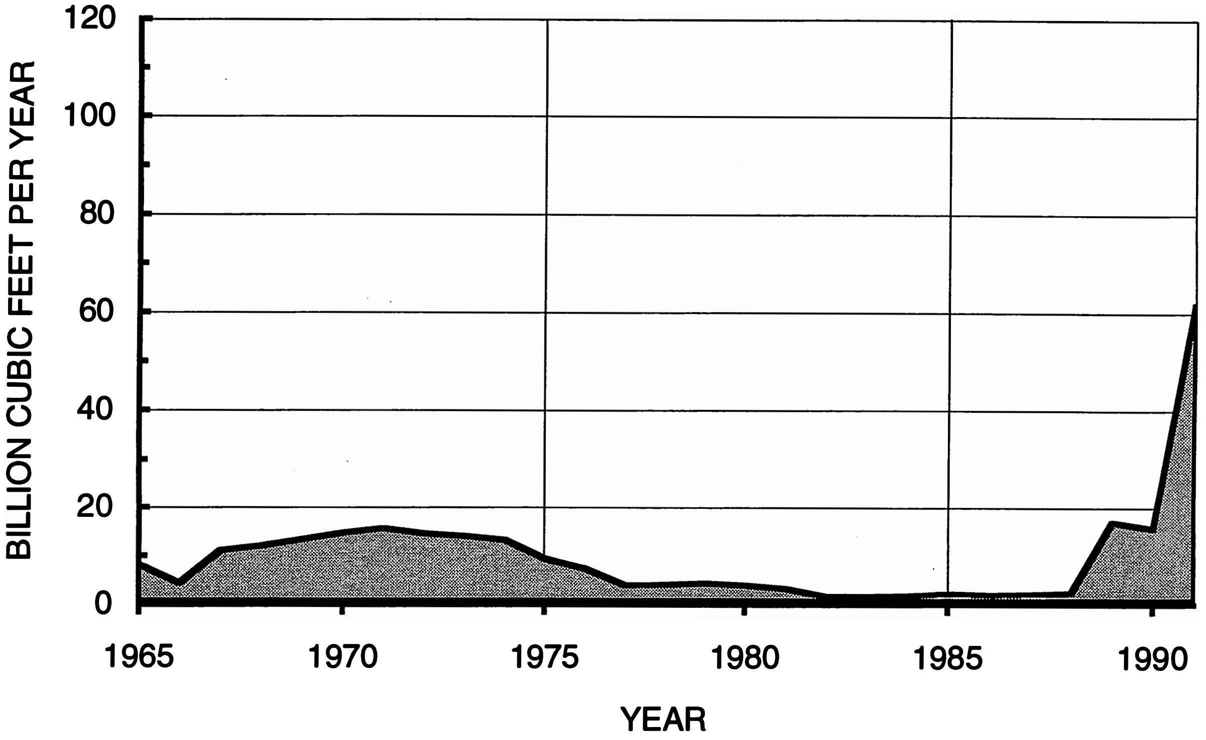

Figure 4-26. U.S. Exports to Mexico—1965 through 1991.

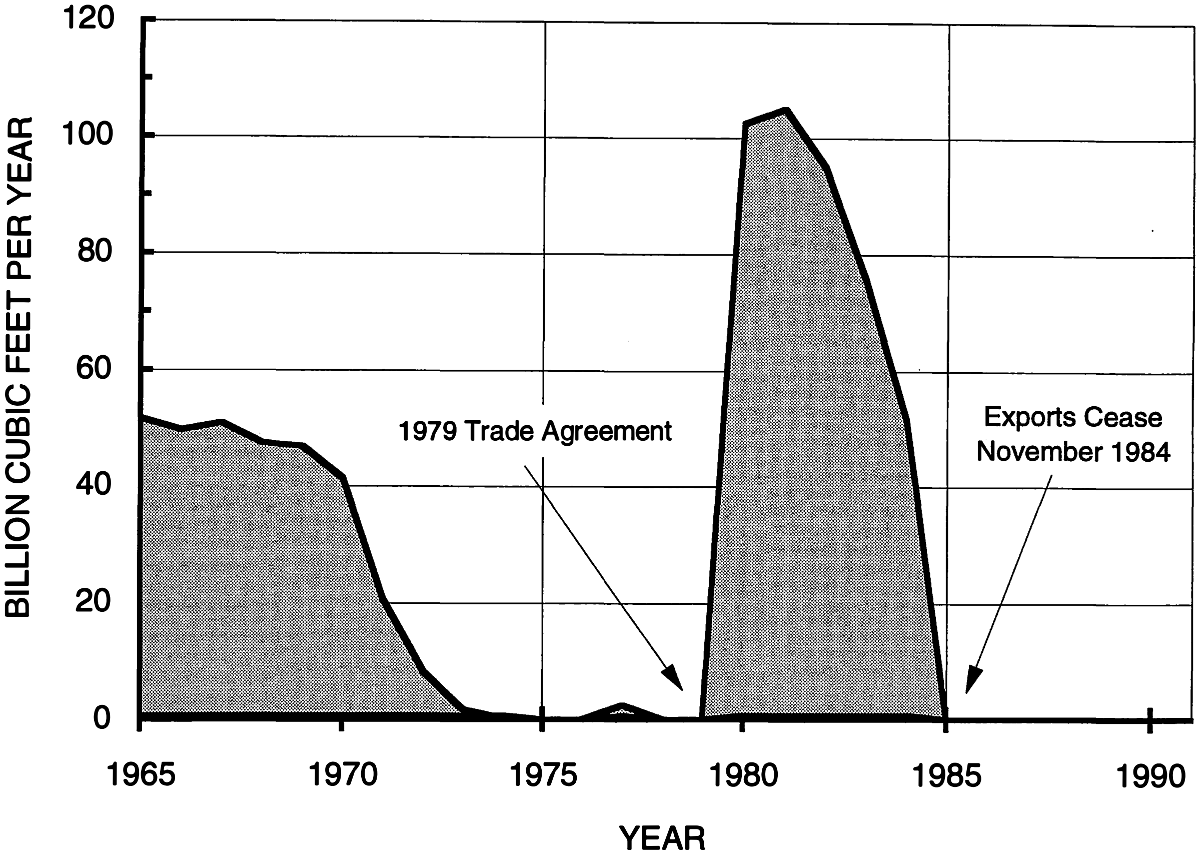

Figure 4-27. U.S. Imports from Mexico—1965 through 1991.

to 300 MMCF/D (110 BCF per year). Volumes peaked at 105 BCF in 1981 and averaged nearly 86 BCF per year between 1980 and 1984 (Figure 4-27).

The International Boundary price received by Mexico in 1984 was approximately $4.40/MCF. At that time, both U.S. and Canadian gas prices were beginning to decline as a result of deregulation initiatives and decreasing demand. Mexico suspended gas sales to the United States in November 1984, declaring a "no export" policy on the grounds that the gas could be of higher value domestically by displacing high sulfur fuel use. This policy continues today, with PEMEX stating that it would require a border price of $3.50/MCF (1991$) in order to resume gas exports.

Future U.S. Exports to Mexico

An immediate effect of Mexico's *de facto* "North-South" gas strategy will be an increase in imports from the United States over the next several years. Beyond diverting indigenous gas supplies to the Mexico City area, industrial growth in northern Mexico and population growth along the U.S. border related to increased *maquiladora* industrial activity will spur natural gas imports. Further growth in imports should come from new demand in the power generation sector. Recently, the Comision Federal de Electricidad has projected that electricity demand in northern Mexico will rise by 5 percent per year through 2000. This will require nearly 8,000 megawatts of new generation capacity, 60 percent of which is estimated to be gas-fired. Many of these facilities may be built by foreign contractors on a Build-Operate-Turnover basis similar to the proposed Tri-National Power project near Tijuana. This approach calls for a contractual agreement in which the facility would be turned back to the Comision Federal de Electricidad after 10 to 15 years of operation. The facilities could be fueled by either U.S. or Mexican sources, creating an opportunity for U.S. gas to compete on an equal basis with indigenous supplies for at least the next 15 to 20 years.

Future Mexican Exports to the United States

Approximately half of the crude oil produced in Mexico is exported. The role of gas however, is significantly different. Between 1980 and 1984, when gas exports to the United States were at their highest levels, exports constituted only 4 to 8 percent of production and thus a much smaller proportion of Mexico's export earnings than oil. However, as the flow of gas has changed direction over the last few years, so has the flow of dollars. In 1991, Mexico's cost of gas imports was over $100 million. While imports of lower cost U.S. gas are a boon to end users in northern Mexico, the loss of so much hard currency is an undesirable situation in a country that is resource-rich and capital-poor. It is this very need to generate foreign currency that may eventually spur increased Mexican gas development. By focusing on developing its large, untapped gas resource (almost 45 percent of Mexico is underlain by sedimentary basins, of which only 10 percent have been explored), Mexico could become a significant supplier to the U.S. market.

Once exports to the United States resume, initial levels will likely be at a rate that is supported by the existing Mexican pipeline infrastructure (300 MMCF/D) from producing regions in the South and market areas in the North. Thereafter, completion of the national trunkline between Monterrey and the border plus addition of compression along the system could allow exports to eventually increase to as much as 1 TCF annually.

NPC Study Assumptions

The NPC study consists of two scenarios: (1) a moderate energy growth scenario, Reference Case 1, and (2) a low energy growth scenario, Reference Case 2. In both scenarios, the data included for Mexico was an exogenous input and not the result of the energy model's calculation. Assumptions made in the analysis of Mexican imports and exports for both scenarios are detailed below and shown in Tables 4-15 and 4-16.

The moderate energy growth scenario (Reference Case 1) assumes that no exports to the United States will occur until the border price reaches $3.50/MCF (1991$). This is in line with PEMEX's current stated policy for resuming gas sales to the United States, although this price level could change in the future depending on Mexico's gas availability and need for hard currency. In the meantime, PEMEX's "North-South" strategy will keep Mexico a net importer through the 1990s as all indigenous production will be consumed by industries in the Ciudad PEMEX and Mexico City/Guadalajara areas. A resumption of exports will occur after the turn of the century and will be driven by a need to generate hard currency. Either rising PEMEX profits and/or the initiation of foreign equity participation will provide the capital required for development.

The low energy growth scenario (Reference Case 2) is based on essentially a flat price for crude oil. As seen above, Mexico, and more specifically PEMEX, is dependent on the revenue generated from oil exports to provide development capital. In a flat oil price scenario, available revenue from oil exports would primarily be utilized to maintain oil production. As such, discretionary funding for gas projects would be severely limited. In this scenario, Mexico would most likely remain a net importer of gas from the United States.

This study recognizes that the key constraint to Mexico becoming a net exporter of gas to the United States is the availability of capital for hydrocarbon development and pipeline infrastructure. As such, an Aggressive Imports Case was developed that assumes an earlier infusion of capital, which would accelerate exports to the United States. A Restrained Imports Case was also developed, which assumes that capital would not be available until the post-2010 period (Tables 4-15 and 4-16).

Analysis

Net gas import volumes to the U.S from Mexico for the reference cases and sensitivity cases are depicted in Figure 4-28. Because the most significant border crossing is McAllen, Texas, the border prices for this location are shown in Figure 4-29.

In the moderate energy growth scenario, U.S. exports to Mexico grow from 60 BCF in 1991 to 250 BCF in 1995 and 330 BCF by the turn of the century. This growth reflects full implementation by PEMEX of the "North-South" strategy with a virtual abandonment of northern Mexican demand to U.S. suppliers. To fulfill

TABLE 4-15

ASSUMPTIONS FOR ANALYSIS OF MEXICAN IMPORTS AND EXPORTS

Moderate Energy Growth Scenario (Reference Case 1)

Mexican exports to the United States, which ceased in 1984 due to unfavorable prices, will not resume until U.S. market prices at the border exceed $3.50/MCF (1991$).

Growing internal demand, spurred by increasing environmental concerns, will consume all domestic Mexican production until well after the turn of the century.

Mexico will adopt a "North-South" gas strategy in the 1990s, with the majority of indigenous production being directed toward industrial and electric utility use in the Mexico City area.

As a result of the above strategy, demand in the northern Monterrey-Monclova industrial center will exceed supply in the 1990s, forcing Mexico to be a net importer through 2000.

The resumption of gas exports to the United States will be driven by a need to generate hard currency. When they restart, initial export levels will be at the rate of 100 BCF per year (300 MMCF/D), which is supported by the existing pipeline and production infrastructure.

Low Energy Growth Scenario (Reference Case 2) and Restrained Imports Case

Includes all the assumptions in Reference Case 1 above, with the exception that due to low revenues, PEMEX is unable to develop the discretionary gas projects post-2000 needed for the country to become self-sufficient in terms of gas supply.

Virtually all new demand in northern Mexico through 2010 is captured by U.S. suppliers. This includes several new power generation projects.

Aggressive Imports Case

The Reference Cases recognize that Mexico's ability to resume gas exports to the United States is dependent on the availability of investment capital. As such, a sensitivity case (based on the moderate growth scenario, Reference Case 1) has been developed which comprehends the early infusion of capital, possibly foreign, to accelerate exports.

the estimated 900 MMCF/D of potential demand by 2000, the existing cross-border pipelines plus the major proposed linkages (e.g., Tri-National) will be near full capacity.

Post-2000, the need to generate foreign currency will spur Mexico's development of its large gas resources. This is reflected in a gradual decline in U.S. imports such that Mexico will become a net exporter to the United States by 2010. The initial level of imports by the United States (110 BCF per year) is consistent with the existing pipeline infrastructure within Mexico and does not require PEMEX to upgrade the present transportation system. This case is similar to other published industry forecasts (Table 4-16).

Beyond 2010, rising gas prices in the United States should continue to favor Mexican gas as a lower cost alternative to frontier Canadian Arctic gas, Alaskan gas, or LNG. Exports from Mexico could ultimately reach as much as 1 TCF per year. Mexico's resource base is more than sufficient to support an export industry of this magnitude.

In the low energy growth scenario, lower oil prices constrain PEMEX from developing the country's natural gas potential. The low growth scenario is identical to the moderate growth scenario through the turn of the century, as exports of gas from the United States rise from 60 BCF in 1991 to 330 BCF by 2000. Post-2000, the lack of development capital begins to have an impact on PEMEX's funding of gas projects. Instead of declining as in the moderate energy growth scenario, exports of U.S. gas continue to grow, reaching 500 BCF by 2010.

TABLE 4-16

ASSUMED NET GAS IMPORTS FROM MEXICO
(Billion Cubic Feet per Year)

	Actual								
	1970	1980	1990	1991	1992	1995	2000	2005	2010
NPC Projections:									
Moderate Energy Growth Case	26	98	(16)	(60)	(110)	(250)	(330)	(180)	110
Low Energy Growth/ Restrained Imports Cases	26	98	(16)	(60)	(110)	(250)	(330)	(420)	(500)
Aggressive Imports Sensitivity Case	26	98	(16)	(60)	(110)	(250)	(180)	20	440
Other Industry Projections:									
Gas Research Institute					0*	0*	100	300	–
Department of Energy					(180)	(180)	250	500	–
Cambridge Energy Research Associates					(255)†	(328)†	–	–	–

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* The Gas Research Institute's current projection does not assume any significant export volumes to Mexico; however, this forecast is currently being revised to reflect Mexico as a net importer during the 1990s.

† Cambridge Energy Research Associates' projection is for U.S. exports to Mexico to increase significantly from the current level of 165 MMCF/D to 600 MMCF/D by 1993 and as high as 900 MMCF/D by 1997. The table reflects the 1997 projection under the year 1995.

In this scenario, U.S. suppliers capture virtually all the new demand growth in northern Mexico.

The Aggressive Imports sensitivity case was developed based on earlier availability of development capital. In this case (see Table 4-16), capital funding for resource development is assumed to be available 5 years earlier than in the moderate energy growth scenario. In addition, development of the gas resource is assumed to be concurrent with a need to generate foreign currency. The border price accepted by PEMEX is thus below their present minimum acceptable price of $3.50/MCF (1991$). As a result, U.S. imports peak in 1995 at about 700 MMCF/D (250 BCF) and then decline as indigenous supply is made available to the northern industrial and power generation markets. In this scenario, Mexico becomes a net exporter by 2005 with total imports by the United States growing to over 1 BCF/D by 2010.

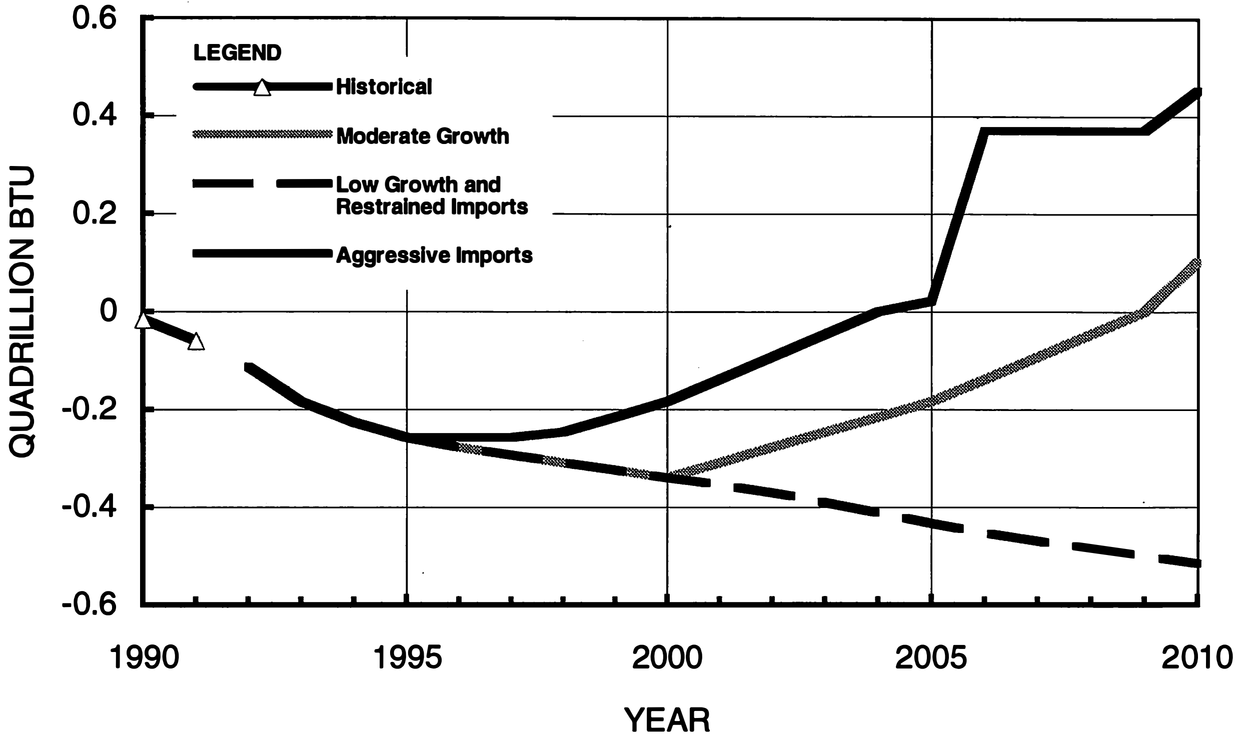
The Restrained Imports Case assumes that lack of capital inhibits gas development. As in Reference Case 2 (low growth scenario), U.S. exports rise from 60 BCF in 1991 to 500 BCF by 2010. Although the export volumes are the same in the Restrained Imports Case and Reference Case 2, the resulting McAllen border price varies by nearly $1.00/MMBTU (1990$) in 2010. This wide swing in price is caused by: the higher lower-48 demand outlook in the Restrained Imports Case (consistent with Reference Case 1, the moderate growth scenario); and lower pipeline capacity between Canada and the U.S. lower-48 (2.1 TCF in 1994 and 2.4 TCF in 2010). As prices move above the $3.50/MMBTU level, PEMEX will be motivated to redirect funds to indigenous gas development. As a result, U.S. exports to Mexico will likely decrease after 2010, as rising Mexican production begins to supplant U.S. gas.

Conclusions

Mexico is rapidly becoming a critical player in the North American gas market, from both a demand as well as a supply viewpoint. In the near term, Mexico will continue to increase imports of U.S. gas as the government adopts a "North-South" strategy aimed at selectively supplying indigenous gas production to the Mexico City area. Northern Mexico will provide a new market for U.S. suppliers, especially those in the Permian and San Juan Basins. Strong industrial growth along the border and in the Monterrey-Monclova area will provide the initial opportunities for U.S. suppliers. This demand base will be augmented by robust electricity demand growth coupled with environmental pressure to replace high sulfur fuel oil with clean burning natural gas. The Mexican market for U.S. natural gas supplies could increase from 60 BCF in 1991 to 250 BCF in 1995 and as much as 330 BCF by 2000.

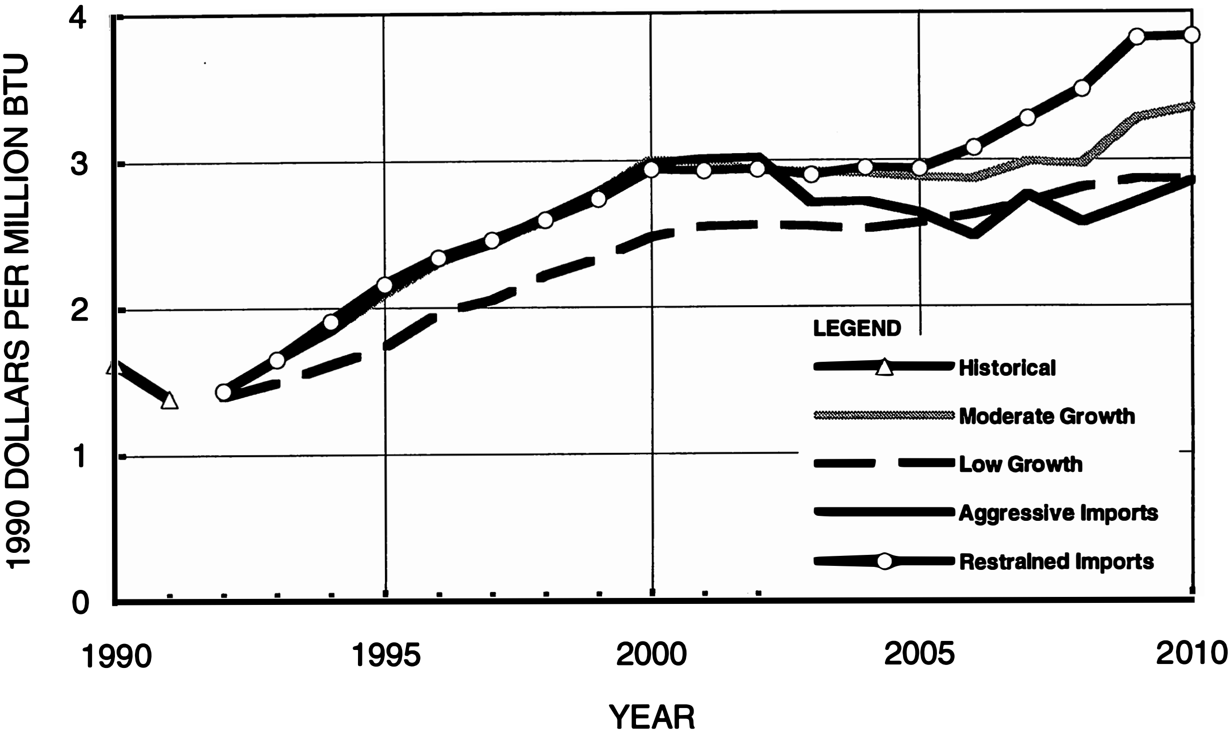
In the long term, Mexico could become self-sufficient in terms of gas supply and resume exports to the United States after the turn of the century. Based on past government statements, Mexico will probably not develop its gas industry until U.S. prices make exports an attractive investment alternative. Mexico could therefore be viewed as a long-term supply source for the United States, given open access and availability of markets.

Mexico is truly a "sleeping giant" in terms of gas potential. Large natural gas reserves are known to exist, despite a lack of historical development focus. Even larger reserves are likely, given the immaturity of exploration for gas in many of Mexico's sedimentary basins. The key to unlocking the country's gas potential is availability of capital and access to markets in the United States. Currently, PEMEX does not have access to equity financing, either private or foreign, because of Mexican constitutional law. Given the



	1992	1995	2000	2005	2010
Moderate Growth	−0.113	−0.258	−0.340	−0.185	0.103
Low Growth	−0.113	−0.258	−0.340	−0.433	−0.515
Aggressive Imports	−0.113	−0.258	−0.185	0.021	0.453
Restrained Imports	−0.113	−0.258	−0.340	−0.433	−0.515

Figure 4-28. Net Gas Imports from Mexico.



	1992	1995	2000	2005	2010
Moderate Growth	1.44	2.10	3.00	2.88	3.35
Low Growth	1.40	1.73	2.48	2.57	2.86
Aggressive Imports	1.44	2.12	2.98	2.64	2.85
Restrained Imports	1.44	2.16	2.94	2.94	3.84

Figure 4-29. Price at McAllen Border Crossing (1990$).

current situation of government-constrained expenditures, coupled with an increasing need to generate hard currency, private investment may be the only option in solving Mexico's gas future. Absent this infusion of development capital, Mexico could remain a net importer of gas for many years to come.

ALASKA

Summary

Historically, Alaskan hydrocarbon activity has focused more on oil than natural gas. However, in addition to large quantities of oil, Alaska has large gas resources. The recoverable gas resource base in Alaska is estimated at approximately 180 TCF, given expected technology development through 2010. Although over 35 TCF of recoverable gas has been discovered, most of it is not economically recoverable at current prices, with only 9 TCF identified as proved. A majority of the gas that has been discovered is in the giant Prudhoe Bay field, over 25 TCF, and is technically recoverable, but is not deemed commercial due to lack of market accessibility. Other Alaskan North Slope structures also contain significant amounts of gas. The issue for Alaskan gas is not one of resource availability, but one of market access.

Demand for Alaskan natural gas is small compared to its supply, and is currently about 400 BCF annually. Over half of this gas is used for oil production activities on the North Slope of Alaska, with the remainder used for LNG exports, chemicals production, and power generation.

Alaska is extremely remote from other gas markets. Bringing large quantities of additional Alaskan gas to external markets requires large-scale projects that are very expensive, have long lead times, and involve complex commercial issues. Two major projects have been proposed for bringing additional quantities of Alaskan gas to market. The Trans-Alaska Gas System (TAGS) would transport North Slope gas to southern Alaska, liquefy the gas, and ship it to Pacific Rim markets as LNG. The Alaska Natural Gas Transportation System (ANGTS) would move natural gas to the lower-48 states via pipeline through Canada. Neither project is under construction at this time, and significant contractual and economic issues must be resolved before either project could proceed.

The gas supply and demand balance developed in the NPC Reference Cases indicates that lower-48 gas requirements can be adequately met until the year 2010 from sources other than Alaska.

Historical Perspective

Alaska generally can be considered as two distinct gas producing regions: South Alaska and the North Slope. South Alaska comprises all of the Cook Inlet area and the production from this region maintains roughly a 60/40 split between non-associated gas and associated gas. The North Slope in the present context refers to the Arctic coastal plain extending from the Beaufort Sea in the north to the Brooks Range in the south, including a portion of the Arctic National Wildlife Refuge.

Gas production from the Cook Inlet area began in 1957 from the Swanson River field. As of 1990, total cumulative production from South Alaska was 3.9 TCF. The majority of this gas has been produced for sale to consumers in nearby areas, such as Anchorage and Kenai, and in Japan, with the remainder reinjected into the reservoir. Trade with Japan required the construction of facilities to liquefy the gas in order to ship it via tankers, as LNG. LNG shipments to Japan began in 1969 and have ranged from 44 to 56 BCF per year since 1970.

North Slope gas production began in 1977 with the start-up of the Prudhoe Bay field. Historically, the natural gas extracted from the North Slope was reinjected into the reservoirs to maximize oil recovery, with approximately 10 percent sold as fuel for oil production facilities and related on-site activities. The Prudhoe Bay, Kuparuk, Endicott, and Lisburne fields, which currently produce oil, contain vast quantities of gas that are expected to be recoverable at relatively low unit production costs. Based on these identified accumulations, the likely potential for gas production from the North Slope is considered great.

Alaskan Gas Resources

The resource potential for Alaska is sizable, although most of the resources are not economically recoverable at current prices. A comparison of existing industry and government resource estimates is provided in Table 4-17. The estimate used for this study is provided in Table 4-18.

Proved Reserves and Reserve Appreciation

Estimated natural gas reserves for the state of Alaska range broadly. At one level, quantities range from approximately 31 TCF to roughly 34 TCF as estimated by the Alaska Department of Natural Resources and the Potential Gas Committee, respectively. These estimates of natural gas "reserves" rely on the perspective that the expected low unit costs of recovery qualifies these volumes as recoverable and therefore reserves. It is not strictly correct, however, in that the lack of a viable transportation system to deliver gas to lower-48 or Pacific Rim markets at present means that the gas will not be produced under existing economic conditions. Economically recoverable proved reserves are estimated at 9.3 TCF by the Department of Energy's Energy Information Administration. Of this total, roughly 3.5 TCF is located in the Cook Inlet area.

Estimates of ultimate recovery from known fields (cumulative production plus proved reserves at a specific date) generally grow over time. Such reserve appreciation occurs as a result of reserve additions from field extensions and new reservoirs, as well as positive revisions resulting from infill drilling, improved technology and enhanced recovery techniques, well workovers, recompletions, and longer productive life of wells encouraged by higher prices. The volume of expected recovery in excess of the cumulative production plus current reserves reflects the expected reserve appreciation, the incremental gains from which are expected to be added over time to known fields. The current study is based on an estimate of 30.4 TCF from reserve appreciation.

TABLE 4-17

EXISTING ESTIMATES OF ALASKAN NATURAL GAS RESOURCES
(Trillion Cubic Feet)

	DOE 1988	PGC 1990
Proved Reserves	**33**	**34**
Conventional Gas		
New Fields	93	–
Reserve Appreciation/Infill	3	–
Subtotal	**96**	**143**
Nonconventional Gas		
Coalbed Methane	–	57
Total Resources	**129**	**234**

– = Not Available.

SOURCES: DOE—Department of Energy, *An Assessment of the Natural Gas Resource Base of the United States* (May 1988). PGC—Potential Gas Committee, *Potential Supply of Natural Gas in the United States* (December 31, 1990).

TABLE 4-18

NPC ESTIMATE OF ALASKAN NATURAL GAS RESOURCES AS OF DECEMBER 31, 1990
(Trillion Cubic Feet)

	Current Technology	2010 Technology
Proved Reserves	**9.3**	**9.3**
Conventional Gas		
Reserve Appreciation*	30.0	30.4
New Fields	76.1	83.7
Subtotal	**106.1**	**114.1**
Nonconventional Gas		
Coalbed Methane	36.8	57.0
Tight Gas	–	–
Subtotal	**36.8**	**57.0**
Total Resources	**152.2**	**180.4**

Basis — Technically recoverable resources incorporating technology advancement through 2010.

*Includes 27.3 TCF discovered but not "proved."

Undiscovered Recoverable Gas Resources

Technically recoverable, undiscovered conventional natural gas resources are estimated to be 76 TCF with current technology, growing to 84 TCF based on expected technological development through 2010. U.S. Geological Survey and Minerals Management Service estimates show that roughly 2 percent of the total is located in the Cook Inlet area. More than 92 percent is thought to be in the onshore and offshore regions of the Alaska North Slope.

An area of considerable interest regarding Alaskan oil and gas resources is the expected recovery from the Arctic National Wildlife Refuge (ANWR). The "1002 area" in ANWR (see Figure 4-30), which is specified in Section 1002 of the Alaskan National Interests Land Conservation Act, constitutes a very promising geologic prospect. This area is thought to be the location in North America with the greatest chance of containing a giant oil or gas accumulation. Recoverable gas in new fields within ANWR, estimated at roughly one-third of the state total, is included in the figures of Table 4-17, even though ANWR is currently closed to exploration and production. While this is a substantial part of the expected recoverable gas volume in Alaska, lack of access to this portion of the resource base does not alter the findings of this gas study for the period through 2010.

The absence of transportation from undiscovered fields outside Cook Inlet at present precludes the economic recovery of gas for external markets from these regions. The construction of an economically viable delivery system would allow the external marketing of this gas, thus raising the expected volume of economically recoverable resources greatly. Two major projects proposed to transport gas from Prudhoe Bay to alternate markets are the ANGTS and the LNG export project, TAGS.

Nonconventional Gas Resources

Nonconventional gas resources include gas in low-permeability "tight" reservoirs, gas in geopressured shales and brines, gas in coal seams, or natural gas hydrates. Available resource assessment results suggest that Alaska contains a large amount of gas in nonconventional deposits. Explicit estimates of recoverable resources from low permeability

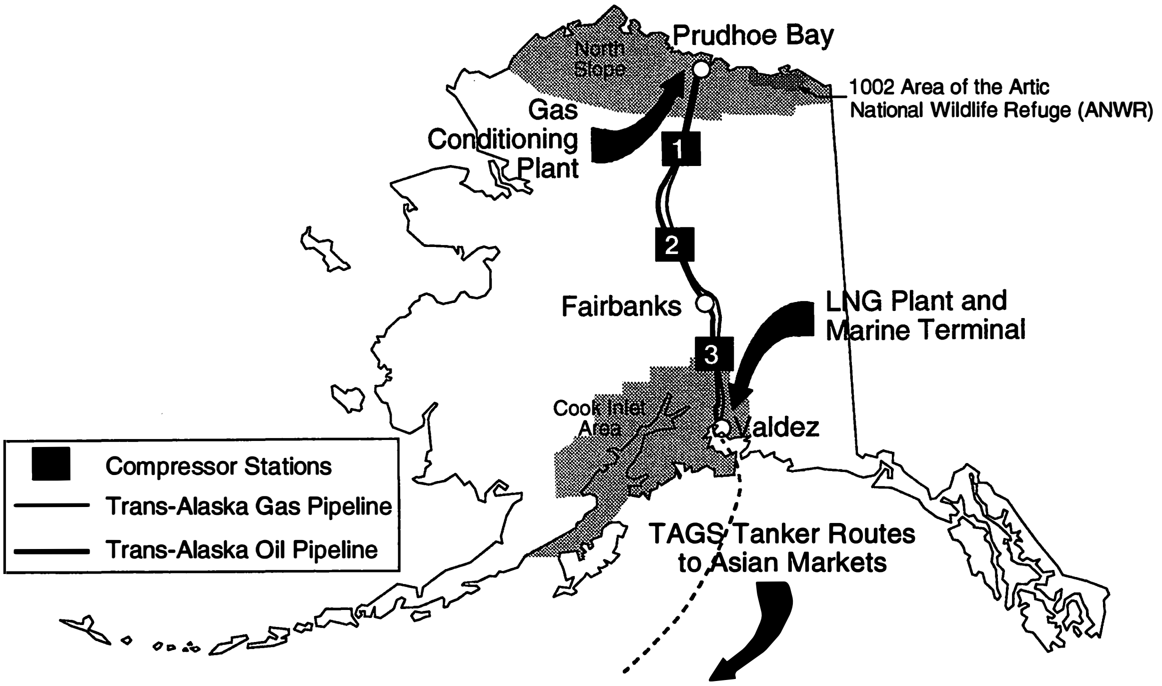

Prudhoe Bay
North Slope
1002 Area of the Artic National Wildlife Refuge (ANWR)
Gas Conditioning Plant
1
2
Fairbanks
LNG Plant and Marine Terminal
3
Cook Inlet Area
Valdez
TAGS Tanker Routes to Asian Markets
■ Compressor Stations
Trans-Alaska Gas Pipeline
Trans-Alaska Oil Pipeline

Figure 4-30. Trans-Alaska Gas System Route Map.

formations are not available, but the estimate for coalbed methane provides a rough indication of the vast potential for the state.

Coalbed methane within Alaska is located primarily on the North Slope. The Cretaceous coals of the North Slope contain 80 percent of the coal found in Alaska. During the coal forming process, approximately 7 MCF of methane per ton of coal is generated. The Potential Gas Committee has published a most likely estimate for this resource of 57 TCF.

Alaskan Natural Gas Demand

The Alaskan gas market is separated from other North American markets because of Alaska's remote location. Alaska has no pipeline access to Canadian or U.S. markets. Given that oil field operations and LNG production are the largest users of natural gas in Alaska, the current Alaskan gas market is unique among U.S. producing regions.

In Alaska, gas demand is concentrated in two geographical areas that are not interconnected by gas pipelines: the southern region around the Cook Inlet/ Anchorage/Kenai area, and the northern region on the North Slope of Alaska. Total natural gas consumption in 1991 was approximately 438 BCF. The two proposed gas projects, ANGTS and TAGS, would expand consumption greatly by reaching markets in the lower-48 states and the Pacific Rim.

Southern Alaskan Gas Demand

Gas is used in the area around Cook Inlet/Anchorage/Kenai by industrial, chemical, power generation, utility, and hydrocarbon production customers. Gas in southern Alaska is also used to produce LNG for export to Japan. The Cook Inlet plant is the only U.S. facility exporting LNG to Japan. Approximately 30 percent of the gas consumed in the southern Alaskan region is for LNG production, with 26 percent for ammonia and urea production and 21 percent for power generation. Demand, and therefore production, in South Alaska is not expected to change dramatically, growing at only 0.5 percent or less annually.

Northern Alaskan Gas Demand

More than one-half of Alaskan gas demand is on the North Slope. Over 80 percent of this gas is used to support oil production operations. The Trans-Alaska Pipeline System and natural gas liquids extraction represent most of the remaining gas demand.

Prudhoe Bay oil field operators recently installed an enhanced gas handling facility as part of an expanded miscible injection project to improve oil recovery. Further recycling capacity, which will be on-line in 1995, will increase annual demand an additional 35 BCF beginning in 1995. Northern Alaskan gas demand could increase after 2001 due to the completion of heavy oil extraction projects. The economic viability and exact timing of any heavy oil project is highly uncertain. However, given the sizable heavy oil resource base and oil price assumptions similar to those in the moderate energy growth scenario (Reference Case 1), some heavy oil extraction project is possible. Reinjection of North Slope gas for increased oil recovery poses an operational and economic barrier to early extraction of the gas for either sale or other on-site use.

North Slope gas also could be used to supply Asian markets. The proposed TAGS project (shown in Figure 4-30) would move gas from Prudhoe Bay by pipeline to Prince William Sound, where the gas would be liquefied and shipped by LNG tanker to expected markets in the Pacific Rim. Over 16 TCF of gas would be required over the life of the project.

Reference Case Analysis

The availability of significant gas resources in the Prudhoe Bay field has prompted interest in a project that would bring Alaskan gas to lower-48 U.S. markets via Canadian pipelines. The Alaska Natural Gas Transportation System (shown in Figure 4-31) would follow the existing Trans-Alaska Pipeline System to central Alaska and then through Canada to the United States. Part of the pipeline was constructed by the early 1980s, extending from near Caroline in Alberta to the U.S. border. The pipeline currently supplies Canadian gas to the U.S. West Coast and Midwest markets, but would move Alaskan gas upon completion of ANGTS.

Changes in market conditions have delayed completion of the ANGTS project, which would bring over 2 BCF/D to lower-48 markets. While much technical work has been done, sig-

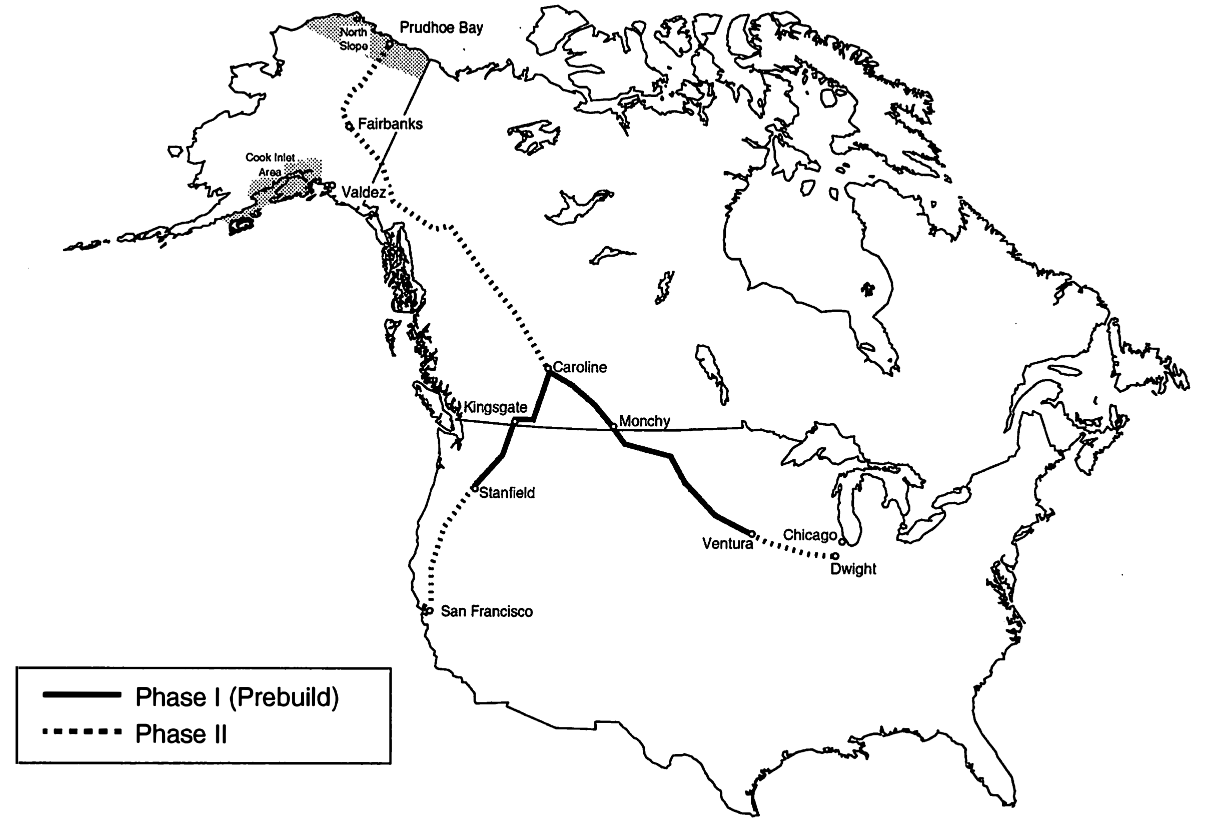


Figure 4-31. Alaska Natural Gas Transportation System.

nificant commercial issues remain for the project, the cost of which has been estimated at well in excess of $10 billion. Foothills Pipe Lines in June 1988 estimated the cost of conditioning and transportation to lower-48 markets for Alaskan North Slope gas at $3.31/MMBTU (1990$). This cost, which excludes production costs, exceeds lower-48 wellhead prices through most of the study period.

Much of the enabling legislation for ANGTS was included in the Alaska Natural Gas Transportation Act of 1976. The Office of the Federal Inspector has recommended repeal of this legislation. However, in April 1992 the Secretary of Energy sent draft legislation to Congress proposing that the Office of the Federal Inspector be abolished and its functions transferred to the DOE. The proposed legislation would also require the Secretary of Energy to report to Congress by a specified date on whether any of the laws and regulations relating to ANGTS need to continue to be in effect.

Under expected prices in the NPC Reference Cases, delivery of Alaskan gas to the lower-48 states would not be economical before 2010. Beyond 2010, Alaskan gas may have a greater role to play than that currently envisioned. If lower-48 gas prices rise enough to make an Alaskan gas project economically feasible, and other difficult commercial problems can be overcome, Alaskan gas could have a significant impact on the North American gas market.

Conclusions

More than 35 TCF of natural gas in Alaska, of which about 32 TCF is in the North Slope area, has been identified and can be extracted at relatively low unit costs with current technology. There is significant potential for additional gas to be found. However, the relatively high transportation costs necessary to reach external markets constitute a significant economic barrier that has impeded recovery of the gas. These circumstances are expected to continue affecting the outlook for Alaska gas beyond the study time frame.

The gas supply and demand balance developed in the Reference Cases indicates that lower-48 gas requirements can be adequately met until the year 2010 from sources other than Alaska.

Two alternatives have been proposed to transport Alaskan North Slope gas to market. The ANGTS project, certificated by the Federal Energy Regulatory Commission in 1977, would move natural gas to the lower-48 states via pipeline through Canada, interconnecting with existing sections of the prebuild system. The TAGS proposal would transport North Slope gas to southern Alaska, liquefy the gas, and ship it to Pacific Rim markets as LNG. It has been suggested that the 32 TCF of discovered resources could support only one of these two alternatives. However, the total projected resource base of 130 TCF in the North Slope area should accommodate the development of more than one project.

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Historical and Projected Oil and Gas Consumption, June 1991, Alaska Department of Natural Resources, 1991.

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LIQUEFIED NATURAL GAS

Summary

World trade of liquefied natural gas (LNG) amounted to 7.0 BCF/D (72 billion cubic meters [BCM] per year) in 1991. Of that amount, only 2.4 percent (64 BCF) was imported by the United States. Over the next 20 years, LNG imports by the United States will continue to be a supplemental source of natural gas for peak shaving and to replace higher cost energy alternatives.

Due to location and shipping distances, the most likely sources of LNG for the U.S. market will be from countries in the Atlantic and Caribbean regions. Currently, Algeria is the only supplier of LNG to the United States, and production capacity will continue to be limited until its revamping program is completed in 1996. Therefore, in the near term, import volumes will remain relatively small reflecting the intense competition with the higher-priced European markets for Algerian supplies. In the longer term, with the completion of Algeria's revamping program and the projected start-up of LNG projects in Nigeria and Venezuela by the late 1990s, additional production capacity will be available to the U.S. market. Beyond 2010, LNG may also be supplied from projects in Norway and Trinidad. Since the United States must continue to compete with the European market, U.S. gas market prices will be a critical factor in determining the volume of LNG actually imported by the United States.

The United States has four LNG receiving terminals with a total regasification capacity of 2,190 MMCF/D. Currently, only the Everett, Massachusetts, and Lake Charles, Louisiana, facilities are operational; the Cove Point, Maryland, and Elba Island, Georgia, terminals have been idle since 1980.

For both Reference Cases, the projected "market clearing price" for each trade was compared to projected market prices at each terminal to determine when LNG is a competitive gas supply and how much volume will be required. On this basis, Algeria remains the only supplier of LNG to the United States in the short term. Nigerian volumes are relatively price competitive and will begin flowing as soon as the Nigerian project starts up. The cost-to-market of the Venezuela project is not competitive until after 2010.

Under Reference Case 1 (moderate energy growth scenario), LNG imports will increase from 64 BCF in 1991, reaching 253 BCF by 1999, and remaining flat thereafter. Under Reference Case 2 (low energy growth scenario), import volumes will increase more slowly, reaching 253 BCF by 2001. The Everett and Lake Charles facilities will continue to operate, while the Cove Point and Elba Island terminals will not re-open until possibly the post-2010 period due to lack of available supply at market-competitive prices.

Introduction

Liquefied natural gas is simply natural gas that has been reduced to a liquid state by cooling to -260°F. The transformation of gas into liquid is accompanied by a volume reduction of approximately 600 to 1. Table 4-19 lists these and other physical properties of LNG. Detailed information concerning LNG Safety may be found in Appendix D.

In 1991, nearly 25 percent of the gas traded in the international market was sold as LNG. As shown in Table 4-20, world LNG trade in 1991 totaled 7.0 BCF/D (72 BCM) of natural gas. LNG imports to the United States for 1991 were 64 BCF, 2.4 percent of world LNG trade.

The majority of LNG liquefaction capacity is in the Pacific Rim (Indonesia and Malaysia), but these sources are not readily available to the U.S. market. Due to location and shipping distances, the most likely sources of LNG to the United States will continue to be countries in the Atlantic and Caribbean regions.

TABLE 4-19

PHYSICAL PROPERTIES OF LIQUEFIED NATURAL GAS

Extremely low temperature: -260°F (-162°C).

Liquefaction results in a volume reduction of approximately 600 to 1.

Weight is about 29 pounds per cubic foot, slightly less than water. LNG will float on water.

Odorless and colorless, LNG looks like boiling water. When exposed to atmospheric temperature and pressure it "boils off" (expands very rapidly).

LNG cannot burn or explode in its liquid state.

Momentary exposure is harmless, but extended skin contact with LNG will cause "freeze burns."

In the vaporous state, when still very cold, the regasified LNG is heavier than air and will hug the ground. This gas vapor cloud is highly visible because it is enshrouded by water vapor condensed from the surrounding air. Once the gas vapor warms, it becomes lighter than air and will dissipate harmlessly.

History of U.S. LNG Imports

During the 1970s, the United States was emerging as a major importer of LNG. LNG was to be used as supplemental fuel to offset perceived shortages in domestic natural gas supply and to displace higher-priced fuel oil. As the energy shortages of the early 1970s persisted and prices continued their steep rise, particularly the increase in oil prices during 1973-74, LNG was viewed as a welcome alternative.

By 1979, U.S. LNG imports had peaked at 253 BCF per year. During the early 1980s, changing market conditions and deregulation of the natural gas industry adversely affected LNG imports. As a result of the Natural Gas Policy Act of 1978 and FERC actions, pipelines were limited in their ability to roll-in the cost of higher-priced supplies, such as LNG. This restriction, coupled with the fact that LNG was being imported under long-term, 100 percent take-or-pay contracts with prices linked to higher-priced fuels (such as crude and fuel oil), severely limited the competitiveness of LNG. LNG contracts of the early 1970s lacked any provisions to adjust to a changing gas market. By 1987, all LNG imports from Algeria, the only major supplier of LNG to the United States at that time, had been suspended, as shown in Table 4-21.

In 1988, LNG imports resumed to Distrigas's Everett, Massachusetts terminal, and, in 1989, the Trunkline LNG facility in Lake Charles, Louisiana also resumed operations. Purchase contracts for both projects have been renegotiated and contain pricing mechanisms that now are more market-oriented. The other two U.S. regasification terminals, located in Cove Point, Maryland (Columbia LNG), and Elba Island, Georgia (Southern Natural Gas), have been idle since operations ceased in 1980.

TABLE 4-20

INTERNATIONAL LNG TRADE
(Billion Cubic Meters)

	1980	1985	1990	1991
Algeria to:	6.67	12.63	18.97	18.00
France	2.12	7.85	9.31	8.54
Belgium	0.00	2.40	3.90	4.03
Italy	0.00	0.00	0.00	0.13
Spain	1.28	1.67	3.20	3.60
U.K.	0.84	0.00	0.00	0.00
U.S.A.	2.43	0.71	2.47	1.70
Japan	0.00	0.00	0.09	0.00
Libya to:	1.94	1.04	1.24	1.79
Italy	1.35	0.28	0.00	0.00
Spain	0.59	0.76	1.24	1.79
Abu Dhabi to Japan	2.60	3.11	3.20	3.27
Australia to Japan	0.00	0.00	3.94	4.85
Brunei to Japan	7.49	6.86	7.21	6.36
Indonesia to:	11.48	19.94	27.53	27.79
Japan	11.48	19.94	23.49	22.50
South Korea	0.00	0.00	3.08	3.39
Taiwan	0.00	0.00	0.96	1.90
Malaysia to:	0.00	5.92	8.61	8.78
Japan	0.00	5.92	8.61	8.71
South Korea	0.00	0.00	0.00	0.07
U.S.A. to Japan	1.16	1.37	1.36	1.37
World	**31.34**	**50.87**	**72.06**	**72.21**
U.S.A. Imports (% World)	7.8	1.4	3.4	2.4

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1 Billion Cubic Meters = 35.3147 BCF

SOURCE: Cedigaz.

U.S. LNG Suppliers

All imports currently received by the United States are from Algeria under long-term contracts with Sonatrading (Sonatrach's marketing company). Sonatrach, the Algerian state oil and gas company, has moved toward a more market-responsive pricing stance in its most recent contract negotiations with U.S. buyers. The FOB price of the LNG (i.e., the price paid for the volume loaded onto the LNG tanker) is linked to the actual market price of regasified LNG sold in the United States. Revenues are shared based on agreed upon percentages; some contracts contain minimum price provisions.

Through the mid-1990s, LNG imports will be constrained by lack of additional supply from Algeria. By the late 1990s, two additional sources of LNG are projected to come on-stream: Nigeria and Venezuela. Projects in Trinidad and Norway are also possible during this time period, but those volumes would probably flow to Europe, rather than the United States. Beyond 2010, additional supplies could come from expansion of any of the Atlantic

Basin projects. A summary of potential U.S. LNG supply is shown in Table 4-22.

Algeria

Currently, Algeria is the only viable supplier of LNG into the U.S. market, but contractual demands outstrip its production capacity. Algeria is the second largest producer of LNG in the world. Production in 1990 was 675 BCF (19.05 BCM), decreasing to 635 BCF (18 BCM) in 1991.

As shown in Figure 4-32, Algeria has four LNG production facilities: Skikda, located in the east, and Camel, Arzew I, and Arzew II located in the west. Because of design and port limitations, Skikda and Camel can load only smaller LNG vessels; Arzew I and Arzew II can load the smaller vessels as well as 125,000 m^3 (2.7 BCF) class vessels, such as those serving the U.S. market. Although the Algerian liquefaction facilities were designed to produce 3.1 BCF/D (30.5 BCM per year), they are currently able to operate at only 70 percent of capacity.

Sonatrach has contracted with Bechtel, Kellogg, and Sofregaz for a massive revamping program to return the facilities to 100 percent of nameplate capacity (see Table 4-23) at an estimated cost of $2.2 billion. The revamp process should begin in 1992 and will last about three years. There are also plans to de-bottleneck the facilities to increase annual production capacity to 3.3 BCF/D (33.7 BCM) by 1996.

The additional capacity that will be created by the revamp project cannot be considered entirely available to the United States. As shown in Table 4-24, all Algerian production is

TABLE 4-21

LNG IMPORTS INTO THE UNITED STATES*
(Billion Cubic Feet)

Year	Import Volume	% U.S. Lower-48 Net Imports	% U.S. Lower-48 Supply
1970	0.4	0.1	0
1971	1	0.2	0
1972	2	0.2	0
1973	3	0.3	0.01
1974	0	0	0
1975	5	0.5	0.03
1976	10	1.1	0.05
1977	11	1.1	0.06
1978	84	8.8	0.43
1979	253	20.2	1.25
1980	86	8.8	0.43
1981	37	4.1	0.19
1982	55	5.9	0.31
1983	131	14.3	0.78
1984	36	4.3	0.20
1985	24	2.5	0.14
1986	2	0.2	0.01
1987	0	0	0
1988	17	1.4	0.11
1989	42	3.2	0.22
1990	84	3.1	0.43
1991	64	3.7	0.40

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*All imports from Algeria except one 1986 Indonesia shipment.

SOURCE: U.S. Energy Information Administration.

TABLE 4-22

MAXIMUM POTENTIAL LNG SUPPLY TO THE U.S.
(MMCF/D)

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
From Algeria:																				
Current Deliveries*	184	213	213	213	213	213	213	213	213	213	213	213	213	213	213	213	213	213	213	213
Excess capacity Arzew I & Arzew II†	87	58	53	116	126	182	299	416	416	416	416	416	416	416	416	416	416	416	416	416
Total Possible Supply – Algeria	271	271	266	329	339	395	512	629	629	629	629	629	629	629	629	629	629	629	629	629
From Nigeria							70	70	70	70	70	70	70	70	70	70	70	70	70	70
From Venezula								560	560	560	560	560	560	560	560	560	560	560	560	560
Maximum Possible LNG Supply – MMCF/D	271	271	266	329	339	395	582	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259
Maximum Possible LNG Supply – BCF/Year	99	99	97	120	124	144	212	460	460	460	460	460	460	460	460	460	460	460	460	460

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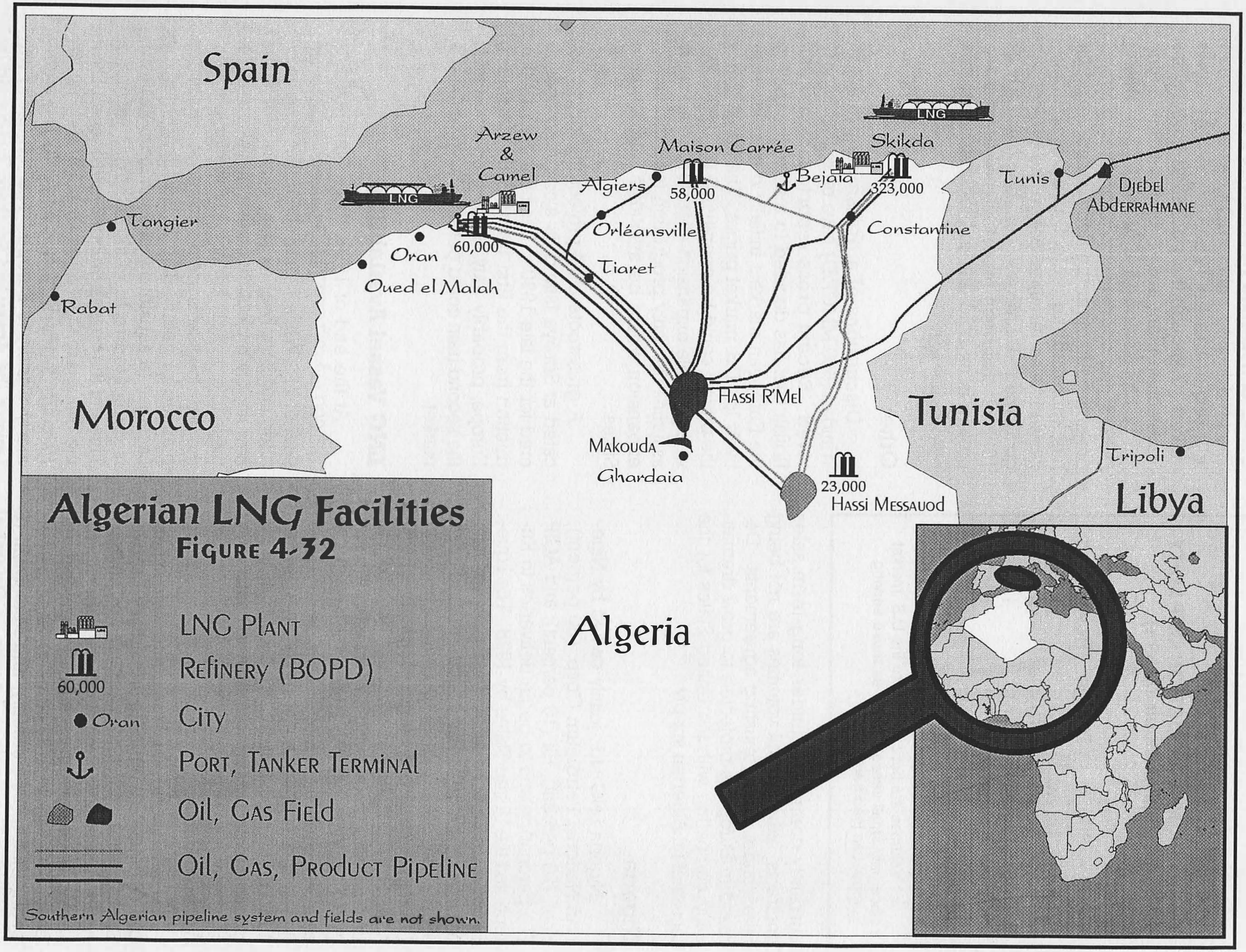
*Current level of takes assumed to be constant.

†Arzew I and II are the only facilities that can load the 125,000 m3 class LNG vessels that will be used in the U.S. trade.

Arzew I & II facilities are used primarily for:
- 2.0 BCM of Gaz de France Contract 2 and all of Contract 3
- 0.5 BCM of Spanish Contract; may cease once the revamp of the Skikda facility is completed
- All of Belgium Distrigas
- All U.S. contracts
- All of Turkey
- All of possible Portugal
- All of possible Italy



Algerian LNG Facilities

Figure 4-32

Southern Algerian pipeline system and fields are not shown.

TABLE 4-23

ALGERIAN PRODUCTION CAPACITY (Billion Cubic Meters)

Plant — Site	Design	After Revamping
GL1Z — Arzew	10.5	11.6
GL2Z — Arzew	10.5	12.6
GL4Z — Camel*	1.6	1.6
GL1K — Skikda*	7.9	7.9
Total	**30.5**	**33.7**

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* Volumes are not available to the U.S. market since only small vessels (such as those serving Europe) can load here.

currently committed under long-term sales contracts, although full volumes are not being taken under all the existing agreements. Demand in Europe is projected to grow dramatically, competing with the United States for the incremental Algerian supply.

Nigeria

Nigeria LNG Ltd., jointly owned by Nigerian National Petroleum Corp. (60 percent), Shell (20 percent), Elf (10 percent), and AGIP (10 percent), plans to begin deliveries to Europe and the United States by 1998. The liquefaction facility will be located in the Niger Delta at Bonny Island near Port Harcourt (see Figure 4-33) and is estimated to cost $3.5 billion (1991$). Initial production capacity of 570 MMCF/D (5.7 BCM per year) has been sold to Italian ENEL (350 MMCF/D), Spanish Enagas (100 MMCF/D), Gaz de France (50 MMCF/D), and U.S. Distrigas (70 MMCF/D). The LNG facility will consist of two trains and will require five 125,000 m^3 class tankers. There are plans for possible expansion early in the next century.

Venezuela

Petroleos de Venezuela, the state oil and gas company, through its subsidiary Lagoven SA, is developing the gas fields in offshore northeastern Venezuela for export to the United States (Figure 4-34). Partners in the project are Lagoven (32 percent), Shell (31 percent), Exxon (29 percent), and Mitsubishi (8 percent). The project, known as Cristobal Colon, is designed to export 560 MMCF/D. The LNG facility will consist of two trains and will require three 125,000 m^3 class LNG tankers. Although the published cost for the liquefaction plant is $1.3 billion (1989$), this study has assumed a cost of $2.0 billion (1991$) for consistency with other planned projects. Although the Venezuelan President has approved the project, congressional approval is also required before the project can go forward. Deliveries could begin as early as 1998. It has been reported recently that the project is on hold due to lack of funding and low U.S. gas prices.

Other

Discussions of a grassroots project in Trinidad (560 MMCF/D) have recently been revived. Recent press reports indicate that British Gas has decided to market the LNG to the European markets initially due to the relatively low U.S. market prices. The first phase of the project could be operational by 1998-2000, with possible expansion after 2010. This study assumes that only production from the project expansion would be available to the United States.

A grassroots LNG project in Norway, located at Söröya Island, is also being considered for the late 1990s. It is believed that production from the first train would be sold to Europe, probably Italy, while production from the second train could potentially serve the U.S. market.

LNG Vessel Availability

At the end of 1991, there were six idle 125,000 m^3 (2.7 BCF) LNG tankers in the world fleet of 71. While it may seem that there is an adequate supply of existing vessels for these new supply projects, it cannot be assumed that these idle vessels are actually available. All of the laid-up vessels are dedicated to existing or planned projects. The *Louisiana*, owned by Lachmar (a subsidiary of Panhandle Eastern), is dedicated to the Lake Charles terminal. Three of the vessels will deliver Nigerian LNG: the *Gamma* to the Everett terminal, and the *Port Harcourt* (formerly *Nestor*) and *LNG Lagos* (formerly *Gastor*) to Europe. The remaining two tankers, the *Arzew* and *Southern*, are owned by

TABLE 4-24

ALGERIAN LNG CAPACITY AND CONTRACTED SALES
(Billion Cubic Meters)

Contract/Date Signed*	Expires†	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Gaz de France																					
Contract 3/62	12/02	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Contract 2/71	12/13	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Contract 4/76	12/13	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Contract 12/91	12/02	0.0	0.5	0.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Total		**9.2**	**9.7**	**9.7**	**10.2**	**10.2**	**10.2**	**10.2**	**10.2**	**10.2**	**10.2**	**10.2**	**10.2**	**10.2**	**10.2**	**10.2**	**10.2**	**10.2**	**10.2**	**10.2**	**10.2**
Belgium Distrigas – 1975	12/01	4.2	4.2	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Spain Enagas – 1975	2004	3.5	3.7	3.7	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
USA–Pan National – 1987 (Max 4.5)‡	2009	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
USA–Distrigas (Max 2.4) ‡		0.9	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Contract 1/88	1988+15																				
Contract 3/89	1992-95																				
USA–Shell – 1991 (Max 2.3) §	2009	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Greece–DEP – 1988	2012	0.0	0.0	0.0	0.3	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Turkey–Botas – 1988	2010	0.0	0.0	0.8	1.2	1.7	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Portugal [under discussion]	1995+					1.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Italy-ENEL [under discussion]	1995+					1.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Total Contracts	**1995+**	**18.8**	**19.8**	**20.9**	**22.3**	**25.1**	**27.4**	**27.4**	**27.4**	**27.4**	**27.4**	**27.4**	**27.4**	**27.4**	**27.4**	**27.4**	**27.4**	**27.4**	**27.4**	**27.4**	**27.4**
Liquefaction Capacity – All facilities		30.5	30.5	30.5	30.5	30.5	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7	33.7
Average Efficiency Factor		70%	70%	75%	80%	90%	90%	95%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Total Excess Capacity – MMCF/D		**247**	**150**	**191**	**203**	**227**	**283**	**446**	**609**	**609**	**609**	**609**	**609**	**609**	**609**	**609**	**609**	**609**	**609**	**609**	**609**

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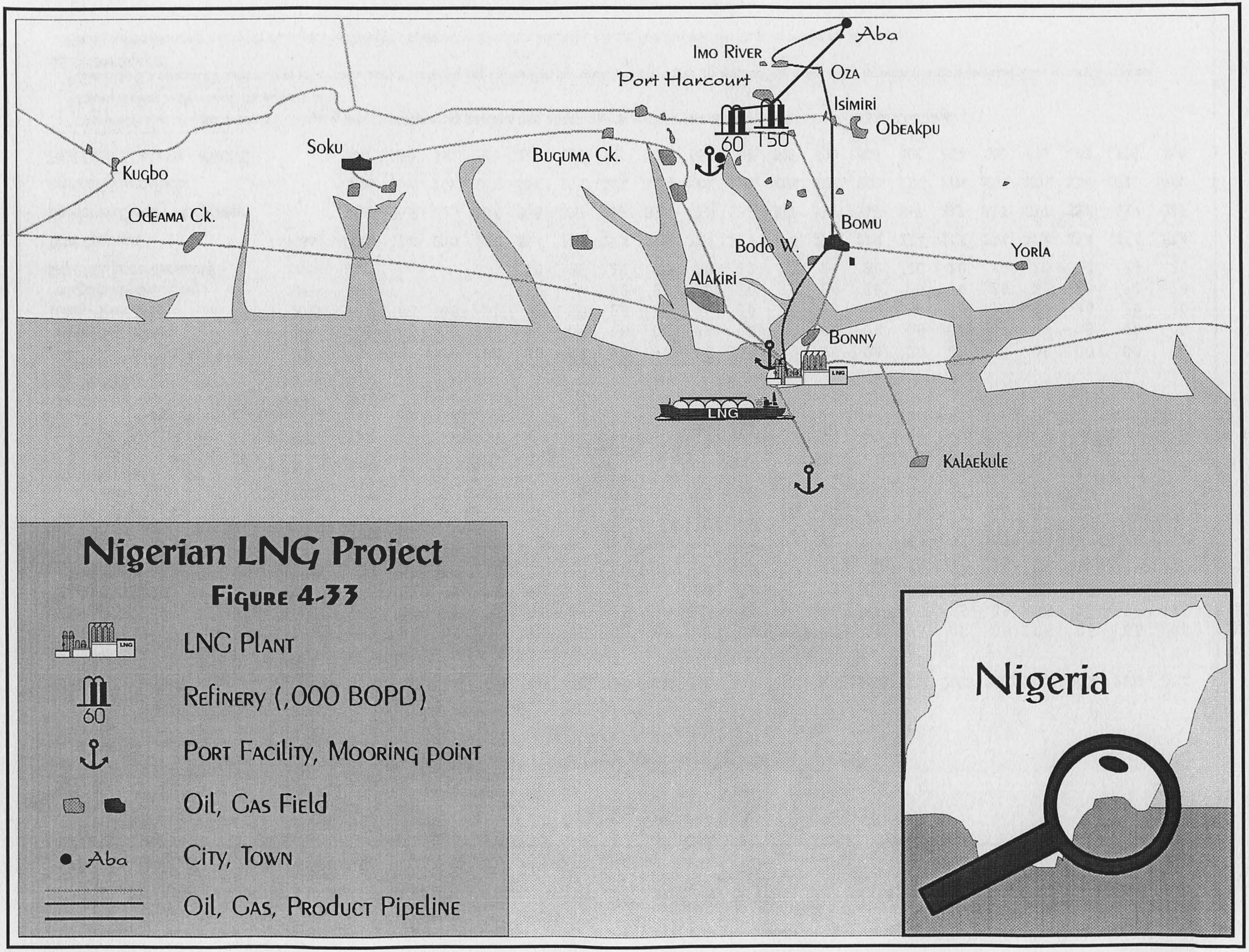
* Other possible sales not included above are: Ruhrgas in 1995, 2.0 BCM/year; Italy (SNAM) in 1996, 2.0 BCM/year; British Gas in 1996, 2.0 BCM/year; Adriatic project in 2000, 4.0 BCM/year.

† Assume all contracts are renewed after expiration dates.

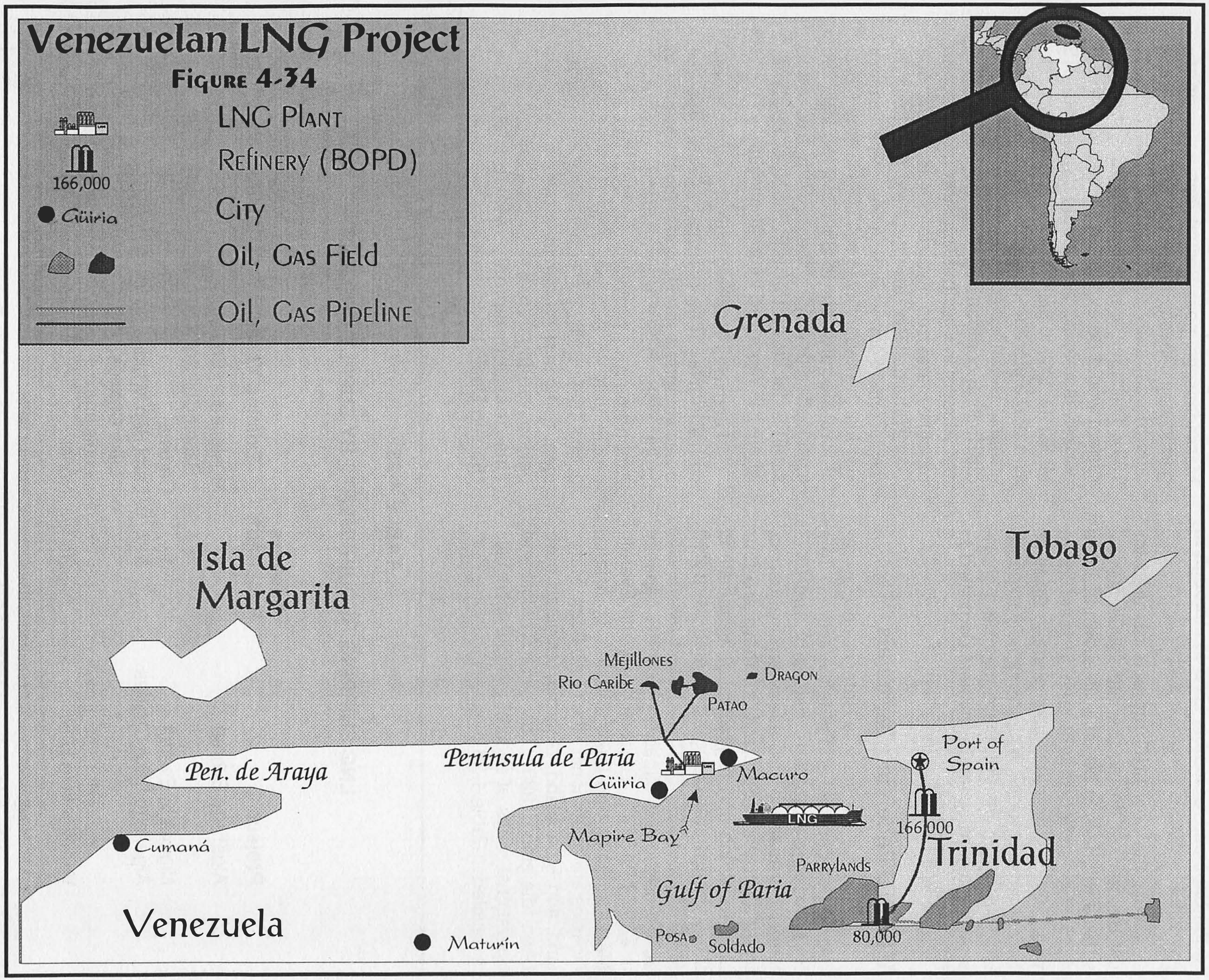
‡ Sales under U.S. contracts are based upon market conditions, and volume buildup may vary therefore the current 1992 level of takes are assumed to be constant. Any increased volumes to the United States will come from excess capacity. See Table 4-22.

§ Shell's contract with Algeria is reportedly still in effect, even though the agreement for Shell to buy Columbia LNG's interest in the Cove Point, Maryland, terminal has fallen through.



Nigerian LNG Project

Figure 4-33



Venezuelan LNG Project

Figure 4-34

Shell and were committed to supplying the Cove Point terminal before the agreement between Shell and Columbia LNG fell through in July 1992.

With the new LNG projects planned for the U.S. market during the late 1990s, several vessels will have to be built, as shown in Table 4-25. Construction will take at least three years, and will probably take place in Asian or European shipyards. With the rapidly expanding Pacific Rim market, there may be a shortage of shipyard space for tankers dedicated to U.S. supply projects.

U.S. LNG Receiving Terminals

Terminal capacity is determined by regasification capacity and pipeline access. To a lesser degree, storage capacity and LNG tanker berth space also affect terminal capacity. As shown in Figure 4-35, there are four LNG receiving and regasification terminals in the United States, ranging in size from 240 MMCF/D to 1000 MMCF/D, based on sustainable regasification capacity. Total U.S. capacity is 2,190 MMCF/D. Currently, only the Everett, Massachusetts, and Lake Charles, Louisiana, facilities are operational; the Cove Point, Maryland, and Elba Island, Georgia, terminals have been idle since 1980. The capacity, cost and operational status of each of the four terminals is detailed in Table 4-26.

Everett, Massachusetts

The Distrigas terminal located in Everett, Massachusetts, near Boston, has a design regasification capacity of 285 MMCF/D, and a sustainable capacity of 240 MMCF/D. In early 1991, Distrigas announced that the send-out system would be expanded by adding one vaporizer, increasing sustainable capacity to 315 MMCF/D. Due to the terminal's location, expansion of the storage facility is impossible. The terminal is connected to Boston Gas (the local distribution company serving the Boston area) and Algonquin Gas Transmission (an interstate pipeline), and can also deliver to Tennessee Gas Transmission (an interstate pipeline) by displacement across Boston Gas. The terminal also has the capability to sell LNG in liquid form at a rate equivalent to 85-100 MMCF/D (90 truckloads per day). The liquid is trucked to satellite facilities throughout New England, where it is vaporized for peak shaving.

Distrigas has two supply agreements with Algeria. The original agreement has been amended many times, most recently in 1988. The 1988 amendment, known as Amendment 3, provides for delivery of approximately 46 BCF per year (17 shiploads). In late 1989, Distrigas signed a second agreement to accept 48 cargoes over a five-year period, varying from 8 to 17 cargoes per year. This deal is commonly referred to as the "Boeing Deal" because it was a counter trade

TABLE 4-25

LNG SHIPPING REQUIREMENTS BY SUPPLY PROJECT

Project	Tankers Required*	Existing Vessels	Potential New Builds
Algeria to Everett	2	Mostefa Ben Boulaid, Bachir Chihani †	1‡
Nigeria to Everett	1	Gamma	0
Algeria to Lake Charles	5	Larbi Ben M'hidi, Lake Charles, Louisiana	2
Venezuela to U.S.	3	None	3

* Number of vessels required is based on full contract takes.

† Available only until 1993-1994 when vessel will be used for trade to Turkey.

‡ Assumes "Boeing deal" is extended.

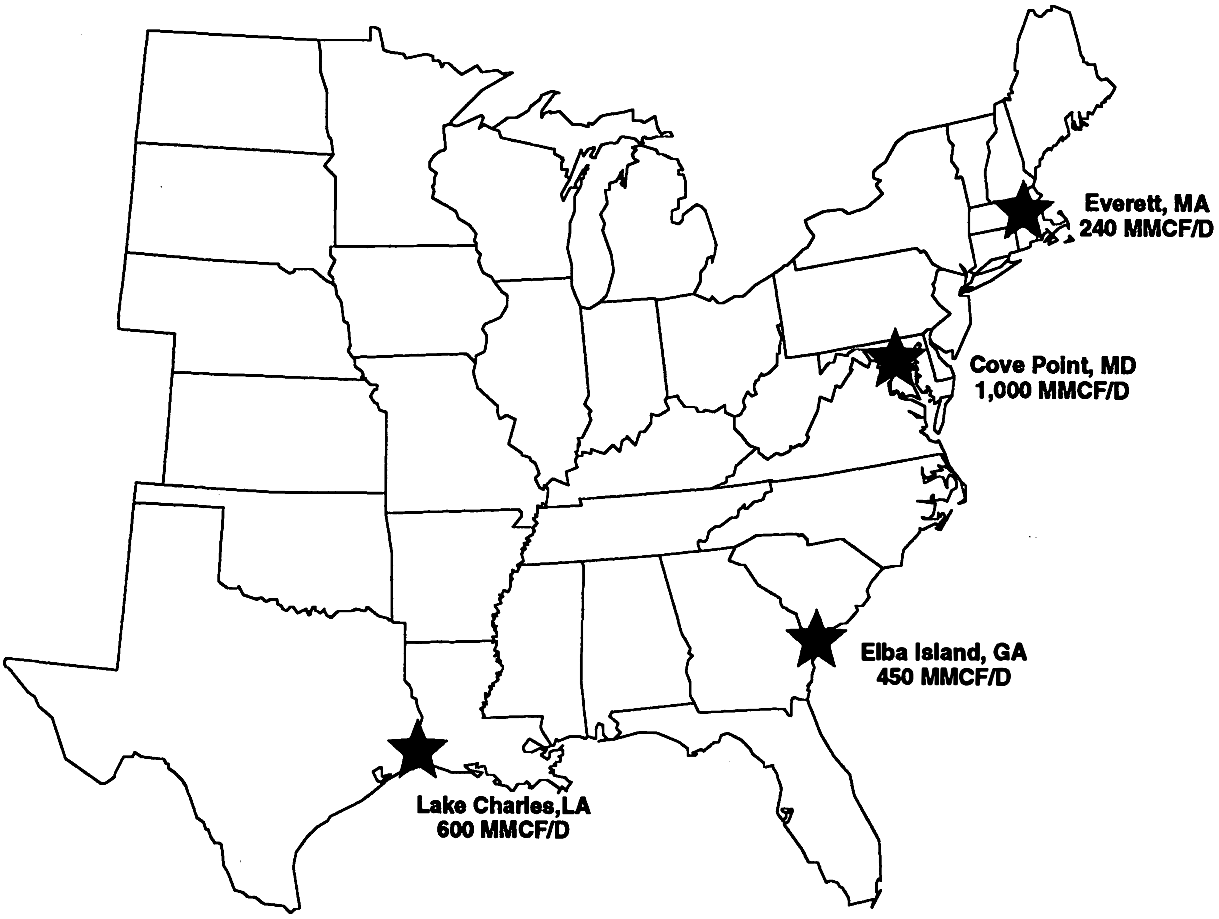


Figure 4-35. U.S. LNG Receiving Terminals' Sustainable Regasification Capacity.

agreement dealing with the sale of three Boeing 767 aircraft to the Algerian state airline, Air Algerie. In 1991, Distrigas imported 30 BCF of gas from Algeria, approximately 34 percent of terminal capacity. This was a 44 percent reduction from the 1990 import level.

Distrigas also owns the *Gamma*, which will be used to transport volumes under the supply contract with Nigeria.

Lake Charles, Louisiana

The Trunkline LNG terminal located in Lake Charles, Louisiana, has a design capacity of 700 MMCF/D, and a sustained capacity of 600 MMCF/D. Trunkline Gas Company's pipeline (capacity 1,000 MMCF/D) is connected to the terminal and there are over a dozen major interstate and intrastate pipelines within 30 miles of the terminal. The terminal has received FERC approval to construct a header facility, enabling other pipelines to connect to the facility. Sustainable capacity could easily be expanded to 1,000 MMCF/D by adding vaporizers. Land is available for a fourth storage tank, and there is sufficient space for an additional tanker berth.

The Lake Charles terminal began operations in 1982 and received 47 cargoes prior to suspending operations in 1983 due to unfavorable market conditions. In April 1987, a new agreement was reached between Sonatrach and Panhandle Eastern subsidiary Pan National Gas Sales, Inc. The new agreement contains no take-or-pay provisions and provides for deliveries of up to 164 BCF per year. Pan National Gas Sales, Inc. imports gas from Algeria and markets it to customers. Trunkline LNG company provides the terminalling service for Pan National. In 1991, Pan National imported

TABLE 4-26

U.S. LNG RECEIVING TERMINALS

	Everett, Massachusetts	Lake Charles, Louisiana	Cove Point, Maryland	Elba Island, Georgia
Status	Operating	Operating	Idle	Idle
Operated By	Distrigas	Trunkline LNG	Columbia LNG	Sonat
First Year of Operation	1971	1982	1977	1977
Last Cargo Received	N/A	N/A	04/11/80	04/09/80
No. Storage Tanks	2	3	4	3
Storage – BCF	3.3	6.3	5.0	4.2
Storage – cubic meters	154,850	286,200	238,500	190,800
No. of Vaporizers	6	7	10	5
Sendout Design/Sustained – MMCF/D*	285/240	700/600	1,200/1,000	540/450
Startup Cost	N/A	N/A	$30-$40 MM	$15-$20 MM
Startup Time	N/A	N/A	12-18 months	12-18 months
Original Cost – $MM	$48	$580	$403	$155
Nominal Sendout Expansion (Design) – MMCF/D	315	1,000	1,400	600
Cost of Expansion – $MM	$8	$65	$140	$100
Approximate One-Way Shipping Distances (nautical miles)				
Algeria	3,300	5,000	3,670	3,990
Nigeria	4,975	6,100	5,330	5,100
Venezuela	2,000	2,300	1,900	1,700
Round Trip Days (including three port days, avg speed = 18.0 kts)				
Algeria	18.3	26.1	20.0	21.5
Nigeria	26.0	31.2	27.7	26.6
Venezeula	12.3	13.6	11.8	10.9
Number of Lifts/year (340 days operating year)				
Algeria	19	13	17	16
Nigeria	13	11	12	13
Venezeula	28	25	29	31

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* Distrigas sells LNG in liquid form at the rate of 85-100 MMCF/D. Sonat is pipeline restricted to 350 MMCF/D.

34 BCF of gas from Algeria, approximately 16 percent of terminal capacity. Imports increased 11 percent compared to 1990 levels.

Under Section 7 of the Natural Gas Policy Act, Trunkline LNG was required to file for a Certificate of Public Necessity and Convenience from the FERC prior to re-opening. The terminal was re-certificated by the FERC on November 14, 1989; the regulatory process took over two years to complete, and the terminal was required by the FERC to be an "open-access" facility. LNG deliveries under the new agreement began in December 1989.

Panhandle Eastern Corporation also owns two 125,000 m^3 class LNG vessels, the *Lake Charles* and *Louisiana*.

Cove Point, Maryland

The Columbia LNG terminal in Cove Point, Maryland, has a design capacity of 1,200 MMCF/D with a sustainable capacity of 1,000 MMCF/D. The terminal is connected to Columbia Gas Transmission's mainline in Loudoun County, Virginia, through an 86-mile pipeline. Reactivation of the terminal will take 12 to 18 months at a cost of $30-40 million. To date, Columbia LNG has not filed with the DOE for import authorization or with the FERC for recommissioning of the terminal. Capacity of the terminal could be expanded to 1,400 MMCF/D with the addition of storage tanks and vaporizers. Land is available for new tanks, and the two existing berths would be sufficient for this level of expansion.

The original owners of the terminal were Columbia LNG Corp. and Consolidated System LNG Company, who built the facility to receive volumes under the El Paso/Algeria contract (canceled in 1980). In 1982, Consolidated abandoned its 50 percent share in the terminal and Columbia became the sole owner. Columbia sold 9.2 percent of its interest in the facility to Shell for $18.5 million in November 1988; the agreement called for Shell to purchase a total of 50 percent interest in the facility for an estimated $90 million. In November 1991, Shell amended its original purchase agreement and agreed to buy Columbia's remaining 90.8 percent interest in the terminal for $110 million. On July 16, 1992, Shell notified Columbia that it would not proceed with the purchase. According to press releases by each party, several preconditions outlined in the purchase agreement, which would have allowed the sale to go further, were not met.

Columbia LNG does not have access to any shipping capacity.

Elba Island, Georgia

The Southern Natural Gas (Sonat) terminal at Elba Island, Georgia, has a design capacity of 540 MMCF/D, with a sustainable capacity of 450 MMCF/D. Although the two pipelines from the terminal to Savannah have a combined capacity of 1,000 MMCF/D, the terminal's capacity is constrained to 350 MMCF/D by the 100-mile pipeline connection from Savannah to Wrens, Georgia. A major pipeline expansion project would be needed to move a larger volume of gas out of Savannah. The terminal has been idle since 1980, and will require 12 to 18 months to restart at a cost of $15-20 million. There is sufficient land to build another terminal of the same size as the existing facility. With the addition of one tank and two vaporizers, as well as the pipeline expansion to Savannah, sustainable capacity could be increased to 600 MMCF/D.

The terminal was built to receive volumes under the El Paso/Algeria contract that was canceled in 1980. Sonat has no supply agreements in place at this time, although they have reportedly had discussions with Algeria, Venezuela, and others regarding obtaining sufficient supply for reactivation of the facility.

Sonat does not have access to any shipping capacity.

Study Assumptions

For this study, it was assumed that the only LNG supplies available to the United States in the near term (through 2010) were from Algeria, Nigeria, and Venezuela, and that a stable political climate exists in each of these countries, sufficient to warrant the level of capital expenditures required. A discussion of LNG trade chain components may be found in Appendix E. The basis for calculating the cost-to-market of each existing/potential LNG trade is discussed below. Actual calculations are shown in Appendix F.

Gas Production and Liquefaction

The published Venezuelan cost estimate of $1.3 billion for the grass roots liquefaction facility appeared low in relation to other projects, therefore, an estimate of $2.0 billion (1991$) was used. Annualized capital costs were calculated based on a 20 percent return over 20 years. Capacity utilization was assumed to be 100 percent. Annual operating costs were estimated from industry standards.

Nigerian liquefaction costs were not developed, since an estimated FOB contract price to be paid by Distrigas has been reported in the press.

Shipping

Shipping costs were based on a typical 125,000 m^3 (2.7 BCF) class LNG vessel. Capital costs were estimated at $260 million (1991$) each for new vessels and $60 million (1991$) each for "used" vessels. Capital costs were annualized based on a 12 percent return over 20 years. Operating costs were estimated based on industry experience. Shipping costs for existing supplies from Algeria were taken from various publications.

As discussed above, this study assumed capital recovery when calculating shipping costs. Where existing vessels are used, capital costs could be considered sunk, and the vessels could operate to recover operating costs only. This would reduce shipping costs dramatically and enable a lower cost-to-market.

U.S. Regasification Facilities

Considering the amount of unused regasification capacity in the United States and the ability of the existing terminals to expand, this study assumed that no new LNG receiving facilities will be built.

Original capital costs of the four existing terminals were considered sunk costs; the terminals were assumed to operate to recover only operating costs and new capital expenditures. Annual operating costs for each terminal were assumed to be $15 million (1991$). While this is not an accurate reflection of the actual costs incurred by each of the terminals, it is reasonable and was chosen as an average for modeling purposes. Any capital outlays required for reactivation or expansion were annualized based on a 14 percent return over 20 years. Various publications were used to estimate reactivation and expansion costs.

Market Clearing Prices for LNG

The "market clearing prices" used in each of the reference cases and the sensitivity runs are shown in Table 4-27.

Existing Algerian sales contracts with Distrigas and Pan National were assumed to continue at current levels, regardless of price. Imports under these contracts will expand when LNG can receive a price of at least $2.50/MCF (1991$). This was assumed to be the minimum sales price the Algerians would accept for new sales volumes. It has been reported that Distrigas has agreed to pay Nigeria an estimated FOB price of $1.80/MCF (1991$).

The projected "market clearing price" for each trade was then compared to projected spot market prices at each terminal to determine when LNG is a competitive gas supply and how much volume will be required. It was assumed that LNG will be sold under long-term baseload contracts and will, therefore, receive a premium (estimated to be 7.5 percent) over spot gas prices in the market area served by the terminal. This approach was considered the most reasonable overall, recognizing that actual contract terms, corporate operating policy, and marketing strategy could affect the actual volume buildup at each terminal.

Outlook for U.S. LNG Imports

Total LNG imports by the United States under each of the reference case scenarios are shown in Table 4-28. The estimated LNG market price and import volumes for each terminal are shown in Appendix G. LNG imports rise modestly as a percentage of the U.S. supply portfolio, increasing from 0.4 percent in 1991 to 1.4 percent in 2010. As previously noted, actual contract terms and market(s) served may dictate a different volume buildup for each terminal than the results calculated under each of the study's scenarios.

In the short term, Algeria remains the only supplier of LNG to the United States. Nigerian volumes are relatively price competitive, and will begin flowing as soon as the Nigerian project starts up. The cost-to-market of the Venezuela project is not competitive

TABLE 4-27

LNG MARKET CLEARING PRICES
(1991$)

		Min. Vol. (MMCF/D)	Max. Vol. (MMCF/D)	Price ($/MCF)
Everett, MA	Algeria (curr. supply)	110	110	–
	Algeria (add'l supply)	0	130	2.50
	Nigeria	0	70	2.55
Lake Charles, LA	Algeria (curr. supply)	110	110	–
	Algeria (add'l supply)	0	340	2.50
	Venezuela	0	150	4.15
	Venezuela	0	400	4.25
Cove Point, MD	Venezuela	0	560	4.20
Elba Island, GA	Venezuela	0	350	4.20
	Venezuela	0	210	4.50

Note: Calculated prices have been rounded to the nearest nickel.

Calculation of Market Clearing Prices:

	Prod. & Liquef.*	Shipping†	Regasif.‡	Total	Terminal Operating Volume (MMCF/D)§
Everett, MA:					
Nigeria	1.800	0.561	0.204	$2.565	241-310
Lake Charles, LA:					
Venezuela	3.310	0.742	0.081	$4.133	451-600
Venezuela	3.310	0.742	0.189	$4.241	601-1,000
Cove Point, MD:					
Venezuela	3.310	0.643	0.230	$4.183	0-560
Elba Island, GA:					
Venezuela	3.310	0.603	0.290	$4.203	0-350
Venezuela	3.310	0.603	0.596	$4.509	351-560

* Contract price of $1.80 FOB Nigeria; refer to Appendix F Table F-1 for Venezuela.

† Refer to Appendix F Table F-2; Nigeria trade uses a "used" ship; Venezuela uses new ships.

‡ Refer to Appendix F Table F-3; average cost for specified terminal operating volume.

§ Refer to Appendix F Table F-3; Lake Charles and Elba Island have different prices for Venezuelan supply, since accepting full volumes (up to 560 MMCF/D) from Venezuela will require expansion of the terminal (i.e., additional capital expenditure).

until after 2010. If the project starts up before 2010, the LNG will likely flow to European markets.

The Everett, Massachusetts, and Lake Charles, Louisiana, terminals remain open, and import volumes rise slowly and then remain flat through the remainder of the study time frame. Capacity of the Everett facility will expand as planned, but no expansion of the Lake Charles terminal will be required. Based on this study's economic analysis, the Cove Point,

TABLE 4-28

LNG IMPORT VOLUMES — TOTAL U.S.*

Year	Moderate Energy Growth Scenario BCF/year	Moderate Energy Growth Scenario MMCF/D	Low Energy Growth Scenario BCF/year	Low Energy Growth Scenario MMCF/D
1990	84	230	84	230
1991	64	175	64	175
1992	80	219	80	219
1993	92	252	80	219
1994	113	310	80	219
1995	121	332	92	252
1996	131	359	122	334
1997	172	471	147	403
1998	228	625	153	419
1999	253	693	178	488
2000	253	693	228	625
2001	253	693	253	693
2002	253	693	253	693
2003	253	693	253	693
2004	253	693	253	693
2005	253	693	253	693
2006	253	693	253	693
2007	253	693	253	693
2008	253	693	253	693
2009	253	693	253	693
2010	253	693	253	693

* Assumes an average of 1,080 British thermal units per standard cubic foot.

Maryland, and Elba Island, Georgia, facilities will not re-open until possibly the post-2010 period due to lack of available supply at market-competitive prices.

Several factors may lower the volume of LNG actually imported by the United States. Delays in completion of Algeria's revamping program, or the start-up of the Nigerian project could significantly affect the availability of LNG to the U.S. market. Increases in European demand or an increase in the price differential between Europe and the United States could also impact supply availability. Another consideration is the availability of tankers for the increased trade from Algeria to the United States.

There is some upside potential to the projected import levels. If U.S. deliverability is lower than projected, or if gas demand for power generation is higher than projected, some of this incremental demand would be met by increased imports, including LNG.

Conclusions

In the near term, U.S. LNG import volumes will remain small, comprising only 0.5 percent of total U.S. natural gas supplies. After additional LNG supplies become available to the United States in the late 1990s, imports could increase to 1.4 percent of U.S. supplies, to 252 BCF per year in 2010.

Over the next 20 years, importation of LNG into existing U.S. facilities will continue to be a supplemental source of natural gas for peak shaving and to replace higher cost energy alternatives. LNG provides an ideal source of reliable baseload supply to customers located in the market area served by the terminal, such as cogeneration facilities and electric utilities.

CHAPTER FIVE

TECHNOLOGY

SUMMARY

OBJECTIVE:

Determine the past impacts of technology on the resource base and costs, project the rate of technology growth and impact into the future and ensure that the impact of technology on both resources and costs is adequately reflected in any work of the Source and Supply Task Group.

DEFINITIONS:

Technology Advancements are all changes to the business of exploring for, development of, and production of natural gas resulting from the application of both tangible equipment and new conceptual knowledge embodied in such things as equipment, products, methods, ideas, and resource concepts.

Technology Impact is the aggregate result of all changes in the application of both tangible and intellectual property leading to reduced costs or the identification of new reserves.

RESULT:

Technology has made significant impacts on both the costs and availability of natural gas over the past two decades, and it is expected to make even greater impacts in the future.

Impact on Costs. During the past two decades, technology advancement has acted to reduce drilling costs by almost 3 percent per year below what they would have been in the absence of technology advancement. The rate appeared to be accelerating with more effect in the 1980s than in the 1970s. This rate is expected to continue to accelerate and is projected to impact costs at the rate of 4 percent per year in the future. THIS DOES NOT IMPLY THAT ABSOLUTE DRILLING COSTS WILL *DECLINE* BY 4 PERCENT PER YEAR. Rather, it indicates that technology is expected to hold drilling costs below what they would otherwise be in the *absence* of continued advancement at a rate of about 4 percent per year.

Impact on Resources. A 1972 NPC study concluded that the "ultimate discoverable" natural gas resource base for the lower-48 was 1,580 trillion cubic feet (TCF) including past production. The current study finds a comparable number of 1,825 TCF. Thus, technology advancement has acted to expand the accessible resource base by 0.7 percent per year during the past two decades, and it is expected to continue this expansion during the next two decades.

Background

Technology advancement is "the engine" that has brought, and is expected to continue to bring, new resources into the economic realm of the resource base estimates. This is accomplished by lowering costs below levels that would exist without new technology, and by developing new processes, equipment, and methods to add additional sources to the technically recoverable resource base. Technology advancement impacts all costs and resources. However, the most visible impacts tend to be in the exploration of hard-to-find and expensive-to-produce resources.

The estimates of the natural gas resource base included in this study indicate a large, currently economic resource base. Historically, estimates of the remaining resources at any point in time have tended to be about the same. This can be primarily attributed to technology advancements. However, these advancements do not occur until they are needed. For example, there was little need for technology (know-how) for the development and production of coalbed methane as long as the more conventional gas resources of the United States were perceived to be adequate to supply the demand for gas. When the perception changed to one of scarcity of conventional resources, incentives and efforts were focused to develop and demonstrate the new technology. Now, coalbed methane resources are a significant contributor to U.S. natural gas supply.

Any estimate of the technically recoverable resource base will always be low because it is so difficult to account for the advancements in technology that will determine the size of future estimates. Further, estimators of the resource base attempt to maintain credibility by tending to include only resources that are just slightly beyond currently demonstrated technical capabilities. When estimators make new estimates of the resource base some years later, additional sources will become part of the resource base through technology advancement and offset part or all of those resources that are depleted through production.

The NPC does not wish to imply that the U.S. natural gas resource base is infinite. However, in terms of the 40-year period covered by this study, the magnitude of the resource base and its perceived growth should not be considered a limiting factor if technology continues to advance as it has in the past.

Methodology

The impact of technology on the supply of natural gas was assessed by representatives from the technical organizations of operating companies (six working members), federal government agencies, the Gas Research Institute, and the Bureau of Economic Geology of the University of Texas at Austin.

No statistics are available to indicate explicitly what the impact of technology has been or what the industry would look like without continued technology advancement. Consequently, the process for developing an assessment of the impact of technology was begun by scoping the issues and examining the impact of a few example technologies on the exploration for and production of natural gas. During this initial work, a list of current and possible future technology examples was developed and is included in Appendix H.

The evolution of technology and its effective transfer to operational use is a process that takes place over an extended period of time. Consequently, any assessments could be best determined for decade-long periods of time. Therefore, the past and future were segmented by decade, i.e., 1970s and 1980s for history, with the 1990s and post-2000 as the future.

With this time template for measuring the impact of technology on the upstream natural gas business, attempts were made to assess the impact of individual technology examples by surveying technical specialists in the participants' organizations. This effort was not fruitful in terms of the overall gas resource and cost picture, because any individual technology is likely to affect only a small portion of the resource base at any point in time. It may have a major impact on this small portion, but it is very difficult to actually "see" the impact of this single technology in the aggregate statistics and operations.

Consequently, the technologies were grouped in logical business and activity categories. The categories chosen were exploration, drilling, completion, production, and processing. Some technologies of course overlapped into more than one category. Further, the scope of the assessment activity was broken into two major contributions of technology: the impact on the cost of the gas supplied and the impact on resource base expansion.

Results

Using the category approach, the specialists in participating organizations were queried once again. The results of the individual organization surveys were normalized to get a relative magnitude of the past and indicated future qualitative impact.

The results of the qualitative survey indicate that the impact of technology on both costs and resources is expected to be even greater in the future than in the past.

To quantify the results of the survey information, ICF Resources, Inc., was hired to examine historical data to determine if a statistical methodology for estimating the impact of technology could be developed. ICF Resources has extensive experience in estimating the impacts of technology, including their participation in the 1984 NPC report on enhanced oil recovery and the 1980 NPC report on unconventional gas.

ICF Resources found that drilling costs had been the beneficiary of technology development over the 1970s and 1980s, which resulted in a compound impact of about 3 percent per year. This does not say that drilling costs actually declined by 3 percent per year. Rather, the costs were about 3 percent per year less than they would have been without the technological advancements. ICF Resources complete report is provided in Appendix I.

When the ICF result is applied to the qualitative survey results for drilling, the projection indicates an expected impact in the future of about 4 percent per year.

This quantified estimate of the impact of technology was then translated into parameters for inclusion in the Hydrocarbon Supply Model, which was developed by Energy and Environmental Analysis, Inc. (EEA) for the Gas Research Institute (GRI), and selected by the NPC to project future gas supply. Several sensitivity cases were run with the technology parameters turned off to determine the effects of various values for the input data. The NPC concluded that the projected impact of technology was realistic as portrayed in the reference cases under the assumption that adequate investment in upstream R&D would continue.

INTRODUCTION

Credible information on the past impact of technology and projections of the future impact of technology on natural gas supply were required for this study. The estimates were to be grounded in past results. Even though a model would be used to project gas supply and demand, the model requirements were not to drive the analysis. Rather, it was judged to be much more important to provide information that would help establish credibility for the projections—particularly since past projections have been so pessimistic regarding projected supply response.

A number of studies during the past decade projected future natural gas supply and demand. Many projected declining supply and rapidly rising prices. Most of these projections operated from the finite, exhaustible resource base paradigm. With this assumption, the amount of natural gas available for the projection is a fixed amount, unchangeable over any relevant time period. As the resource is identified and produced, each succeeding increment of resource is characterized as more expensive to locate and produce than the previous increment. This depletion of the highest quality prospects causes this model of the resource base to demand increasing prices for declining supplies.

This paradigm seems completely logical, and in the ultimate sense, it is correct. However, estimating the "ultimate" resource base has proven to be very difficult and is limited in part by the ability to project technology advancement. Given past industry experience and accomplishments, it is reasonable to expect that substantial volumes of natural gas are not yet included in the resource base estimate. This is supported by the fact that commodity prices can vary significantly, but have generally not increased in real terms over the long term. Technology advancement is the primary factor accounting for this phenomenon. As technology advances, it offsets the effects of depletion of the highest quality portions of the resource base as these resources are developed and produced over time.

An alternative paradigm, which better fits historical data, is that estimates of the remaining volume of reserves and resources assessed at any point in time remains about constant.

Reserves are the inventory necessary to support the production rates for a commodity at any point in time. As natural gas is produced and sold, it is withdrawn from inventory. Meanwhile, more is discovered and developed, adding to inventory. An important aspect of this alternative paradigm is that, in a similar fashion to new reserves replacing production, new sources are added to the undiscovered resource base as previously identified sources are transformed into *assessed resources.* Ultimately, some fraction of these resources is converted into reserves through identification and development. Technology advancement and/or price increases provide the mechanism for moving these new sources into the assessable part of the resource base.

This alternative paradigm also recognizes two fundamental characteristics of an exhaustible resource. First, any estimate of a finite, exhaustible resource reflects current industry perceptions and technology. It does not reflect future perceptions and technologies because the estimates must be credible within the framework of the technical knowledge available at the time of the estimate. Consequently, relatively new and poorly known and understood sources are difficult to conceptualize and include in the estimate. As a result, any resource estimate will tend to understate the ultimate resource potential until all possible sources have been defined and extracted.

Second, technology advancement, by improving access under realistic market conditions, serves to counteract the depletion of the currently estimated resource potential and upward pressure on prices. Even under this alternative paradigm, however, the more easily identified reserves and resources are being depleted. As time progresses, the newly discovered fields are generally smaller, or deeper, or lower quality, or more subtle in their trapping mechanisms. However, the new concepts of resource distribution and new extraction technology advancements developed by the industry counteract the effects of depletion by decreasing the costs of discovering and exploiting these resources as well as adding new sources to the assessable resource base. The aggressiveness and focus of the research, development, and implementation program reflects the level of market demand for the next increment of resource.

When this alternative paradigm is used as the basis for projections, it results in more supply at lower cost than the depleting resource base paradigm. It relies on technology advancement to make this possible, and it appears to fit the history of progress made by the natural gas industry in converting more and more potential sources into assessed resources and ultimately into reserves.

Definitions of Technology

DEFINITIONS:

> ***Technology advancements** are all changes to the business of exploring for, development of, and production of natural gas resulting from the application of both tangible equipment and new conceptual knowledge embodied in such things as equipment, products, methods, ideas, and resource concepts.*
>
> ***Technology impact** is the aggregate result of all changes in the application of both tangible and intellectual property leading to reduced costs or the identification of new reserves.*

Technology appears at the industry level as a gradual, but continuous improvement in response to market demand. It is the result of many individual improvements in hardware, processes, and concepts. While the impact of *any single advancement can be very large in its specific application,* it is usually limited to a small segment of the industry at its initial application. Consequently, the sum of these technology advancements appears as gradual, continuous improvement in the ability to assess, drill, and produce natural gas.

This contrasts with the assumption that technology driven impact is a large change resulting from the development of a specific, often hardware, advance. This assumption leads to the misconceptions that technology (1) refers to hardware rather than processes or know-how, (2) is complex and expensive rather than cost reducing, (3) achieves major advances in large steps rather than incremental improvement, and (4) occurs at unpredictable points in time rather than being continuous through time. These misconceptions lead to expectations for very visible and dramatic effects on the industry. While such breakthroughs do sometimes occur, such as with "bright spot" seismic technology and the beginning of coalbed methane activity, they are very rare.

As long as these technological advancements continue to occur and impact the industry at about the same rate, there will be no *apparent* change in the industry except when a new type of source is added to the resource base. Rather, the *apparent* change would be much more dramatic if advances were to cease. Then the depletion of the resource base and the escalations in costs would not be offset. The price and supply impacts would become very apparent, very quickly.

Another reason the aggregate impact of technology is seen as gradual and continuous is the transfer and dissemination of knowledge throughout the industry. This process can take considerable time. Yet, it is a very important part of the process. One company may use a new technology in a particular area and achieve dramatic results. However, the impact on industry as a whole at that time will be minimal. As the technique is proven, it may be adopted by other operations *within the same company*. Then the technique becomes more widely known, and service companies and others begin to employ it. Very gradually, the technique is transferred from operator to operator or service company throughout the industry. In order to enhance the impact of technology, it is important to accelerate and supplement this transfer and diffusion process.

METHODOLOGY

Because the impact of technological change is subtle from year to year but tends to be identifiable over longer periods of time, technological change was characterized by decades. Initially, the impact of individual technologies was assessed and compared to the previous decade on a qualitative basis.

Maximum use of the participants' technical organizations was attempted because these organizations represented the most credible source of information as they contain recognized experts in the exploration and producing industry. Consequently, each representative surveyed technical specialists in their organizations using a list of specific technologies developed by the group. (The list of individual technologies is included in Appendix H.)

The survey provided a broad assessment of the impact of technology improvements on both the costs of exploration and production of natural gas and on the ability of technology to increase the amount of resources indicated to be available for exploitation. These assessments were initially made for specific technologies. However, no methodology was found to aggregate the individual assessments to the functional level. A subsequent survey directly rated the overall impact in each of the five functional areas of exploration, drilling, completions, production, and gas processing. Once this information was developed, it was calibrated using industry statistical data to estimate the quantitative impact for a specific functional area such as drilling. With this calibration point, the other functional areas could be quantified for both the past and the future.

The quantified projections were translated into the parameters required for the supply model used by the study to project future natural gas production. The Hydrocarbon Supply Model is structured to assess the effects of improved technology on industry operations, and requires projections for these technology parameters. In this model, cost improvement is reflected through increases in drilling productivity on an annual footage drilled per active rig basis and exploration efficiency as defined by success rates. The model uses assessments of the rate of resource recovery for the technology effects on resources.

Qualitative Technology Impact Survey

The problem was approached initially by examining specific technologies and qualitatively estimating each technology's impact. Almost anyone can relate anecdotal information about the impacts of specific technological changes. An ordinal scale of 0-1-2-3-4-5 was used to assign the perceived impact of a given technology to each decade. In this scale, 0 means no impact, and 5 means a very large impact relative to the prior decade.

A significant amount of time and effort was spent in developing this initial information. However, while assessments of the impact of individual technologies are relatively easy to obtain, aggregating the information by functional category is very difficult. No ways were identified to establish weights for specific technologies associated with an aggregate area. Yet the aggregation is essential to relate the assessments of the impact of specific technologies to the total impact of technologic change on cost and supply. In the context of gas supply and price, only the total or aggregate impact is meaningful.

Even though the survey of the individual technologies was not explicitly incorporated into the model, it provided a number of anecdotal examples of the impacts for both existing technologies and some that are expected to become significant over the next 20 years. These examples provide support for characterizing both the historical impact and the expectations for the future impact of technology advances. These examples also provided important background for defining parameters that were ultimately used within the model as a quantitative estimate of technological advancement. They are included in Appendix J.

To overcome the aggregation difficulty, the approach was changed to developing assessments directly for five functional categories: exploration, drilling, completions, production, and gas processing. Each specialist was asked to rate the category directly for both history and the future based on their own internal weights for the specific technologies while reviewing the technology lists. Because the two contributions of technology, (1) reduced cost and (2) expanded resource base, were recognized as somewhat separate, the survey was conducted independently for each of the two types of contributions.

The qualitative assessments were developed initially so that the structure and definable parameters of the model would not drive the results and reduce the ability to establish a credible estimate. However, the survey was designed to also provide information to support the description of technologic change required for the model.

A typical response from a company is presented in Table 5-1. In this example, the company believed that the impact of technological advances in improving the costs of exploration was slightly lower in the 1970s than it was in the 1980s and that the impact in the 1990s and 2000s would be about the same as in the 1980s.

TABLE 5-1

TYPICAL COMPANY RESPONSE
TECHNOLOGY IMPACT ON COSTS
Scale of 0 to 5, with 5
representing the greatest impact

	1970s	1980s	1990s	2000s
Exploration	3	4	4	4
Drilling	2	4	5	5
Completion	3	4	5	4
Production	2	4	4	5
Processing	1	2	3	3

The matrices from each company were subsequently normalized across time so that each activity was comparable to the other. This was accomplished by adjusting each row so that the highest value in each row was a 5. For instance, each number in the exploration row would be multiplied by 5/4 so that the values for the decades 1980s, 1990s, and 2000s would be 5. A normalized version of the company's response is shown in Table 5-2.

TABLE 5-2

TYPICAL COMPANY RESPONSE
TECHNOLOGY IMPACT ON COSTS
Normalized scale of 0 to 5, with 5
representing the greatest impact

	1970s	1980s	1990s	2000s
Exploration	3.75	5.00	5.00	5.00
Drilling	2.00	4.00	5.00	5.00
Completion	3.00	4.00	5.00	4.00
Production	2.00	4.00	4.00	5.00
Processing	1.67	3.33	5.00	5.00

Qualitative Survey for Impact on Costs—Actual Results

The composite of the survey results for the impact of technology on costs is shown in Table 5-3. It was developed by averaging the normalized tables from each of the organizations.

Each row of the table should be interpreted independently. That is, although the magnitude of the numbers may be approxi-

TABLE 5-3

TECHNOLOGY IMPACT ON COSTS
Normalized scale of 0 to 5, with 5 representing the greatest impact

	1970s	1980s	1990s	2000s
Exploration	3.1	4.0	4.5	4.4
Drilling	2.1	4.0	4.8	4.7
Completion	3.0	4.1	4.8	4.6
Production	2.2	3.5	4.2	4.6
Processing	2.2	3.4	4.4	4.8

mately the same, it does not mean those technology advancements in completions can be expected to have an equivalent impact on the cost of providing gas as advancements in production. Rather, the table is normalized with respect to time and compares the past with the future.

The results indicate an expectation of increased impact from technological advances in the future relative to the actual impact experienced during the 1970s and 1980s for all five functional categories.

In order to develop a single qualitative estimate of the total impact of technology on the cost of supplying a unit of gas, each functional area must be weighted according to the costs contributed to providing a unit of gas by that function. These weights were developed by each organization during the survey process. Again, each organization was treated with the same validity and an arithmetic average of all responses provided the composite. The weights for all five activities sum to 100 percent. Table 5-4 provides the composite weights.

TABLE 5-4

PERCENTAGE WEIGHTING FACTORS

	1970s	1980s	1990s	2000s
Exploration	25%	25%	23%	20%
Drilling	37%	36%	37%	38%
Completion	19%	17%	15%	14%
Production	13%	14%	16%	17%
Processing	6%	8%	9%	11%
Total	**100%**	**100%**	**100%**	**100%**

The results of this effort indicate the group's expectation for a slight shift in the relative cost of providing a unit of gas from the areas of exploration, and completions to production and processing. The relative role of drilling shows little change.

When the weighting factors from Table 5-4 are applied to the cost survey factors in Table 5-3, an aggregate impact of technology is obtained as presented in Table 5-5.

TABLE 5-5

AGGREGATE IMPACT OF TECHNOLOGY ON COSTS
Normalized scale of 0 to 5

	1970s	1980s	1990s	2000s
Aggregate Impact	2.5	3.9	4.6	4.6

This result indicates that technology advancement acted to reduce costs more in the 1980s than in the 1970s, and it is expected to show even greater impacts in the future.

Whatever the average actual impact was in the 1970s and 1980s, it is expected to be about 45 percent greater overall in the 1990s and post-2000 decades.

Qualitative Survey For Impact on Resources—Actual Results

The resource base survey information was used as a basis for reviewing the resource base estimates to ensure an adequate reflection of technological impacts. The survey indicates an expectation that technology will have an increasing impact on making new sources of natural gas available for exploration. Table 5-6 provides the aggregate result of the survey on resources.

In this result, again, technology advances are expected to have even greater impacts in the future than in the past. One area that is emphasized is gas processing. This indicates an improved ability to process the sour gas resources.

Quantitative Calibration Study

Quantitative estimates of the impact of technology were required for the study. Therefore, some method of calibrating the qualitative

TABLE 5-6

TECHNOLOGY IMPACT ON RESERVES/RESOURCES
Normalized scale of 0 to 5, with 5 representing the greatest impact

	1970s	1980s	1990s	2000s
Exploration	3.3	4.3	4.7	4.8
Drilling	3.0	3.3	4.5	4.6
Completion	3.2	4.5	4.7	4.8
Production	2.9	3.8	4.6	4.9
Processing	2.8	4.0	4.5	5.0

survey results was needed. Since drilling has the most cost information among all the functional categories, this area was studied first. This was accomplished by statistically analyzing the historical well cost data series for industry and estimating the effects of identifiable factors on drilling. The fundamental premise was that the inflation adjusted cost less all other identifiable costs would equal the impact of technology. A time trend variable was included to represent this underlying influence on costs that was assumed to result from technology advancement. The task group, through the National Petroleum Council, contracted with ICF Resources, Inc., of Fairfax, Virginia, to carry out the statistical analysis. If ICF Resources could identify a time trend variable for drilling, they were to extend the costs analysis to other areas where there was sufficient data available.

ICF Resources' objective was to develop a model for historical costs that both provided a good statistical "fit" and was conceptually satisfying. That is, the model should provide a reasonable explanation for the relationships among the postulated variables. ICF Resources' complete report is presented in Appendix I.

ICF Resources, Inc., Results

Drilling Costs: The long-term trend variable indicated a decrease in drilling cost of about 2.8 percent per year over the two-decade period of 1970–1989.

Drilling Costs Analysis

An analysis of drilling costs was undertaken because drilling costs represent the largest and most readily available data base. If an underlying time-trend variable could be identified for drilling, then other costs would be examined. After investigating several alternative models for representing historical drilling costs, ICF Resources concluded that the most appropriate representation was a three-equation model that characterizes supply and demand for drilling. The general terms for this three-equation model are:

- In the demand-for-drilling equation, the quantity of drilling is represented as a function of the price of drilling, oil and gas prices, reserve additions per well, and the rate of production from existing wells.
- In the supply-of-drilling equation, the price of drilling is represented as a function of the quantity of drilling, hourly wage rates for oil and gas workers, average depth for drilling, and the availability of the domestic rig fleet.
- The supply of rigs is determined by a stock flow process, with supply of rigs represented as a function of the lagged stock of rigs and the lagged price of drilling.

This model formulation was selected because it distinguishes between the short-run utilization effects on drilling costs and the long-term impacts of technological change.

ICF Resources used data provided by the Independent Petroleum Association of America on the distribution of drilling and completion costs by expense type, e.g., day rates, fuel, cementing, tubular goods, etc. The items were grouped and analyzed as follows:

- First, all completion and equipment costs were removed from the drilling expenditures survey results (to be analyzed separately), to attempt to arrive at "pure" drilling costs for a well.
- Second, fuel costs for drilling were also removed from the total, assuming that fuel use efficiencies have improved considerably over the last two decades and would be entirely a function of price.
- Third, the cost of well services was removed, under the assumption that the types of services provided today are different than those provided in the early 1970s.
- Fourth, the cost of supervision and overhead was removed, under the hypothesis

that overhead rates and related administrative costs are different today than in the early 1970s, especially as the mix of drilling between majors and independents has changed.

- Fifth, the "other" expenditures category was removed. This category included certain costs, such as depreciation and rig maintenance costs that may be allocated to well drilling, which could have changed over the last decade.
- Sixth, drilling expenditures were adjusted by subtracting completion and equipment costs, supervision and overhead costs, and other costs for depreciation and rig maintenance.

As a result of suggestions from the task group, the following modifications to the representation of drilling costs were made:

- First, drilling data for Appalachia and some Midcontinent states were removed from the data base used for the analyses. These states were Pennsylvania, West Virginia, New York, Ohio, Kentucky, Illinois, Indiana, and Michigan. These data were removed because they are primarily associated with shallow, low-pressure wells, drilled to a large extent by truck-mounted or cable tool rigs. These rigs are not included in the traditional rig-count statistics.
- Second, a lag (of one year) in the available rigs term in the supply of drilling equation was added since the effect of a rig shortage actually shows up in the following year.

For nearly all formulations, the R^2 statistics for all three equations were good (greater than 0.9), and the t-statistics for the defined independent variables were all significant with 95 percent confidence. Finally, the coefficients for all the model variables had the intuitively correct sign. For all formulations, a time-trend term was included in the regression to represent a long-term decrease in the cost of drilling.

Underlying Trend in Drilling Costs

The long-term trend variable indicates a decrease in average drilling costs of about 2.8 percent per year over the two-decade time period with a range of 2.5 percent per year to 3.6 percent per year depending on the particular formulation.

Interestingly, this result is similar to the result found by a 1967 NPC study[1] that examined the impact of technology advances on drilling costs over the period 1953 to 1965. In that study the costs of drilling and equipping wells were analyzed. The actual cost in 1965 was $13.00 per foot. When the 1953 cost of $11.76 per foot was inflated, the expected cost was $19.00 per foot. However, since the actual cost was $13.00 per foot, a savings impact of $6.00 per foot had been experienced. This translates to a costs saving of 3.7 percent per year.

Application of the Quantitative Analysis to the Qualitative Survey

Quantitative analysis of the impact of technology on drilling costs for the 1970s and 1980s indicated a 2.8 percent per year rate of improvement. The qualitative survey numbers from Table 5-3 for drilling for the 1970s is 2.1 and 4.0 for the 1980s. The average number for the 1970s and 1980s is 3.05. The qualitative numbers from Table 5-3 for drilling for the 1990s and post-2000 are 4.8 and 4.7 for an average of 4.75. If the quantitative analysis result of 2.8 percent per year is associated with an index value of 3.05, a simple linear extrapolation yields a value of 4.4 percent per year for the future. There is little reason to use any particular extrapolation system. However, using either exponential or logarithmic systems results in almost the same answer.

These numbers were rounded to generate estimates to *3 percent per year for history and 4 percent per year projected for future impact on cost.*

TRANSLATION OF TECHNOLOGY ASSUMPTION INTO THE HYDROCARBON SUPPLY MODEL

The Hydrocarbon Supply Model, as developed by EEA for the GRI, was selected to provide the methodology for analytical supply projections. This model is a finding rate process model in which steps for finding, developing,

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[1] National Petroleum Council, *Impact of New Technology on the U.S. Petroleum Industry 1946–1965*, 1967, pp. 34-37.

and producing gas and oil are represented using observable and verifiable engineering cost parameters. Improvements in industry performance are introduced into the model as proxies for a menu of continued technology advancements affecting critical operational factors. The description of industry performance in the model represents the average effects of a wide range of technology and practice. The model makes allowances for specific technological improvements in:

- Drilling rig productivity as represented on a feet drilled per rig basis
- Improved exploration efficiency as represented on a geologic success rate basis
- Higher recoveries of discovered resource-in-place through a recovery factor basis
- Expansion of known and technically feasible areas of oil and gas exploitation through the enhanced recovery modules.

Typical scenarios of advancing technology assume specified rates of improvement such as a 2 percent per year increase in the number of feet drilled per rig per year or an absolute level of improvement in a given time period such as an improvement in recovery of 50 percent by the year 2000. These parameters are for the specific technology assumptions and operate on the specific factors.

The model also uses econometric equations with coefficients developed from historical data to project information. By necessity, these coefficients have some advancing technological impacts included. While EEA has made every effort to ensure that the technological impacts are included only once, the specification of specific parameters does not capture the total impact due to technology improvement.

Technology Effects on Costs

Costs affect the economics of all resource categories. They can be changed directly or indirectly. Indirect changes could reflect something like substitution of a horizontal well for a number of vertical wells. While costs per unit of activity would increase in this case, the volume of booked reserves per unit of activity would increase.

Reduced costs do not generally affect the technically recoverable resource; they affect mostly the economics of recovery. The principal costs are associated with drilling and completing wells and lease equipment costs.

Drilling and development costs can be developed internal to the model or specified exogenously. Internal to the model, they are estimated using algorithms to relate them to oil and gas prices plus the level of activity and rig use. These algorithms are based on historical trends.

Reduced drilling and development charges affect all resource categories in the model. The effects of reduced drilling and development charges are relatively uniform across a resource cost curve for onshore regions because of the more aggregate nature of the specification of the onshore charges. Changing offshore drilling and development charges, however, has a less uniform effect on resource cost curves because the relative roles of the charges for drilling, platforms, and equipment change as resource costs increase. This reflects the shift in field sizes as resource costs increase.

The drilling charge algorithms are affected by a minimum price, reflecting an estimated base charge for new wells that would support new investment to expand drilling capacity. When excess drilling capacity exists, as is the case today, drilling charges can be below this base charge because existing capacity can be re-activated. If there is no excess capacity, then drilling charges rise to the base charge to support new investment in drilling rigs, even if the algorithm indicates a lower charge. Drilling charges would remain at this level until the algorithm-based charge catches up or drilling activity falls off.

The critical technology issues for the model regarding drilling costs are to assess the base charge level and to identify the rate of productivity improvement in drilling. The rate of drilling productivity improvement is a determinant of future drilling costs.

Drilling Productivity Improvement

The Hydrocarbon Supply Model has very specific technology parameters. The drilling parameter describes how the rig productivity on an annual feet drilled per rig basis will change over time. The information developed by the task group attempted to capture the total impact of technology advancement. To reconcile the total impact of technology advancement with the Hydrocarbon Supply Model rig productivity parameter, the group examined the annual feet drilled per rig parameter in detail.

The parameter of footage drilled annually per rig has varied considerably over the past years. A study of drilling costs by EEA for the GRI[2] indicated an annual improvement rate of 1.6 percent per year for the period 1969 through 1988. The ICF Resources, Inc. study covered almost the same time period and found a total impact resulting from technology advancement on the cost of drilling of 3 percent per year. This 1.6 percent per year from the EEA study was related to the 3 percent resulting from the ICF Resources study by assuming that the Hydrocarbon Supply Model parameter for drilling productivity improvement represented about *half* of the total impact. The rest of the impact is assumed to be included in the various cost equations based on regression analysis used in the model.

The projected future technology impact of about 4 percent per year on drilling cost was based on the qualitative survey and the ICF Resources study. *This is not a projection that absolute drilling costs will decline at a rate of 4 percent per year.* The correct interpretation of this number is that in the absence of any effects on drilling cost *other than technology*, then and only then would drilling costs decline at 4 percent per year. However, drilling costs are impacted by a number of forces, such as oil and gas prices, which usually have far greater impacts than technology. The equations of the Hydrocarbon Supply Model attempt to account for these market forces in projecting the absolute level of drilling costs.

The annual footage drilled per rig parameter of the Hydrocarbon Supply Model improved at a rate of about 1.5 percent per year during the 20-year period of the ICF Resources study. This represents about half of the total impact of 3 percent per year found by ICF Resources, Inc. Consequently, it was assumed that half of the impact is reflected in this productivity parameter, and the other half is implicitly included in the econometric equations. Thus, *drilling productivity is projected to grow at the rate of 2 percent per year for the projection period.* When this 2 percent per year is added to the 2 percent per year assumed to be included in the econometric equation, the total of 4 percent per year is reflected in the output of the model. Again, this is not a projection that the absolute level of drilling costs will decline by 4 percent per year. It is a projection that technological advancements will act to keep drilling costs below what they would otherwise be in the absence of further technological advancement at a rate of about 4 percent per year.

New Field Exploration Efficiency

New field resource development is the main driving factor in rising gas prices, reflecting the increased costs associated with finding smaller, generally less productive new fields. The effects of increased development in known fields on costs are very small except in the deeper onshore basins and the deeper offshore waters. If exploration costs can be reduced, then the upward pressures on gas prices from new field discoveries would be significantly eased. Reduced exploration costs would also lower the risks associated with exploring new plays and basins, which a preliminary analysis indicates would significantly increase the new field resource base in the lower-48 states. Exploration costs can be reduced directly by improving the exploration efficiency or indirectly by improving the recovery of gas in place from a new field. Exploration efficiency in the model is changed using a drilling efficiency index.

Once again, it is very difficult to develop information on the impact of technology on exploration efficiency. Even in the Hydrocarbon Supply Model, it is very difficult to interpret the input information and relate it to output success ratios. The output success ratios are compatible with the historical information that is available. However, these actual success ratios are affected by many other variables such as field size, price, and demand. The input values relate to a theoretical case in which prospect size and economic characteristics remain constant.

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[2] Energy and Environmental Analysis, Inc., *Drilling Cost Analysis*, Topical report to Gas Research Institute, GRI Contract # 5089-800-1792, November 1989, p. 2-26.

For instance, in the Hydrocarbon Supply Model, successive increments of new field exploration are expected to find smaller and smaller fields, ultimately leading to lower economic success rates under constant economic assumptions.

Actual success rates for new field wildcats were relatively constant at about 10 percent for the period 1950 to 1970. They then increased to about 15 percent for the next 20 years. Economics undoubtedly played a key role in determining the specific success rate.

For purposes of input to the Hydrocarbon Supply Model, the same rate of improvement as in the drilling productivity parameter was used. The qualitative survey found about the same relative rates of change for the two 20-year periods. Consequently, *exploration efficiency was assumed to grow at 2 percent per year.* This is consistent with the alternative paradigm reflecting resource base growth and with the concept of a gradual and continuous rate of improvement in the aggregate rather than single major changes. The industry's statistics will see this gradual and continuous rate even though the impact of a single technological advancement could be very large in its particular application.

Resource Base Increased Recovery and Expansion

With the application of the alternate paradigm, the resource base is allowed to grow through time as technology is developed, allowing greater access to additional sources of supply and greater recovery from known sources. As indicated in Table 5-6, the qualitative survey results indicated that technology advancement is expected to increase the resource base more in the future than in the past. Table 5-7 provides assessments of the resource base for today and 2010. Although the resource estimates were not developed with a rate of change variable, the remaining resource base is projected to grow at an implied annual rate of 1.0 percent per year, while nonconventional resources averaged a growth rate of 2.2 percent per year. Conventional, high permeability gas was not assigned a range of similar potential improvement as the nonconventional resources due to the greater maturity and the higher initial recoveries associated with conventional gas formations. However, the assessed incremental resource in conventional reservoirs is as substantial or greater in this study than in some previous studies.

TABLE 5-7

RESOURCE BASE GROWTH THROUGH 2010

	NPC 1991 Est. (TCF)	Advanced Tech Est. (TCF)	Implied Growth (%/Year)
Conventional	559	616	0.3
Nonnconventional			
Tight Gas	247	364	2.1
Coalbed Methane	62	98	2.4
Devonian Shale	37	57	2.3
Total Resources	905	1,135	1.0

These rates of change set the path for extension beyond 2010. The nonconventional growth rate was adjusted to a flat 2.0 percent per year for all nonconventional sources.

Further support to this study for the alternate paradigm and these implied growth rates is provided by analysis of the growth in the gas resource base estimate from the 1972 NPC report *U.S. Energy Outlook.* The 1972 study indicated a total "Ultimately Discoverable" resource base for the lower-48 of 1,580 TCF, which includes 674 TCF of cumulative production and proved reserves. The comparable estimate for the resource base in this study is 1,825 TCF, including 920 TCF of cumulative production and proved reserves. Thus the 1,580 TCF assessment of the resource base has grown to 1,825 TCF, which is an annual growth rate of 0.7 percent per year. With the survey results expecting greater impacts than in the past, the rates of growth for the resource base shown in Table 5-7 were judged to be reasonable and appropriate for the current study.

MODEL RESULTS AND SENSITIVITIES

The rate of technology advancement plays a key role in determining the future for the natural gas industry. The ability to maintain competitive prices and to provide adequate supply is dependent on the industry continuing to increase its knowledge and understanding of the resource base and developing processes, procedures, and equipment to efficiently extract the resources once they are found.

In order to test the impact of technology advancement on the projections of natural gas availability, a sensitivity case was developed for NPC Reference Case 1 (moderate energy growth scenario) by assuming that there is no further technology advancement beyond 1990 levels for cost factors, recovery efficiency, exploration efficiency, or resource base expansion.

The results indicate that the projected market growth cannot be supported by domestic production without continued technological advancement.

As indicated in Figure 5-1, the industry can maintain a production level of about 17 TCF per year using today's technology. However, significantly higher prices are required to develop this supply as shown in Figure 5-2, which compares the prices for Reference Case 1 with those of the no technology advancement case. By the end of the 20-year projection period, there is almost $1 (1990$) difference between the two cases or almost a 30 percent higher price required to offset the loss of technology advancement benefits.

This sensitivity case also demonstrates the lead time necessary for technology development. There is little impact from the loss of technology development during the first decade of the projection due to the fact that significant advancement has occurred to reach a 1990 level. This makes a significant portion of the resource base economic at these levels of technology. However, the impacts become very apparent during the second decade, and show how essential it is to continue the investment in technology development. The benefits are seldom very apparent during the initial years of investment. However, without this investment, it will be very unlikely that the natural gas industry will be able to support any demand increase with domestic production.

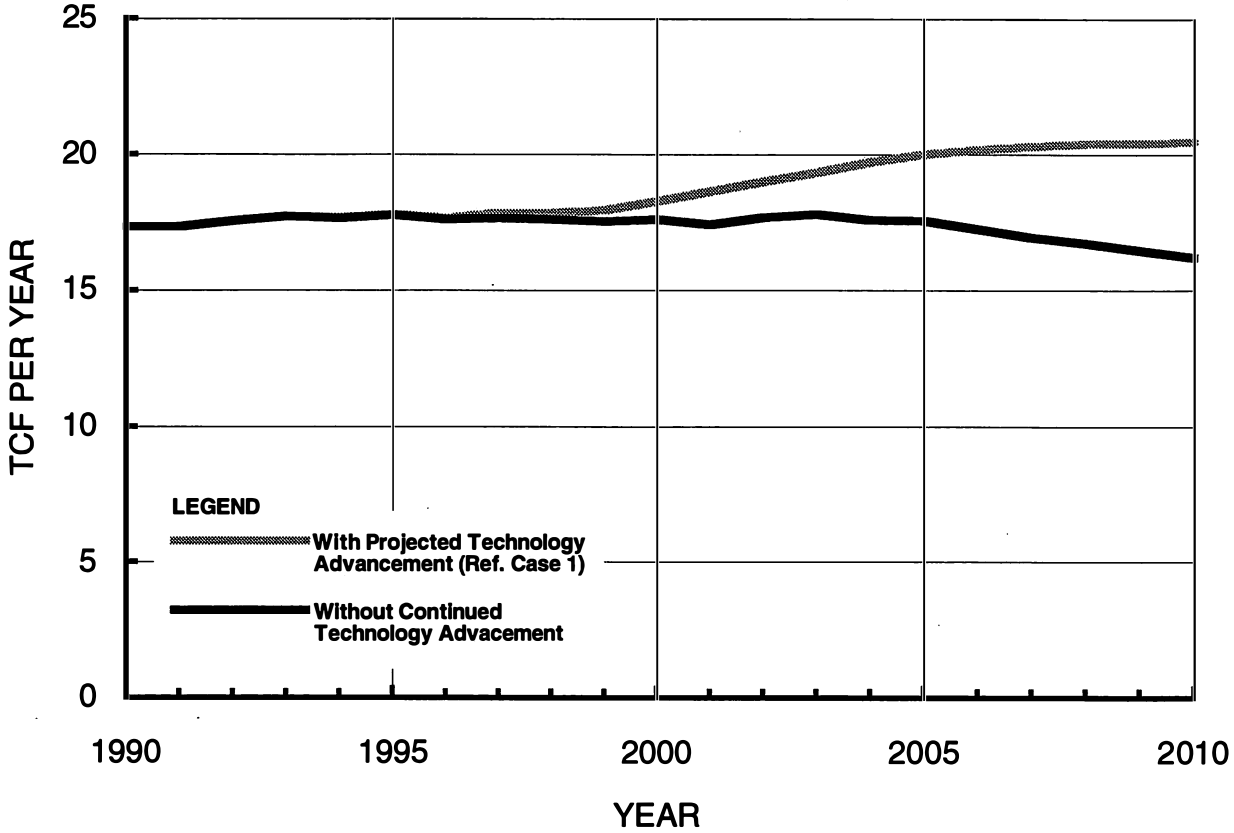

Figure 5-1. Technology Advancement Rate Impact on Future Natural Gas Production.

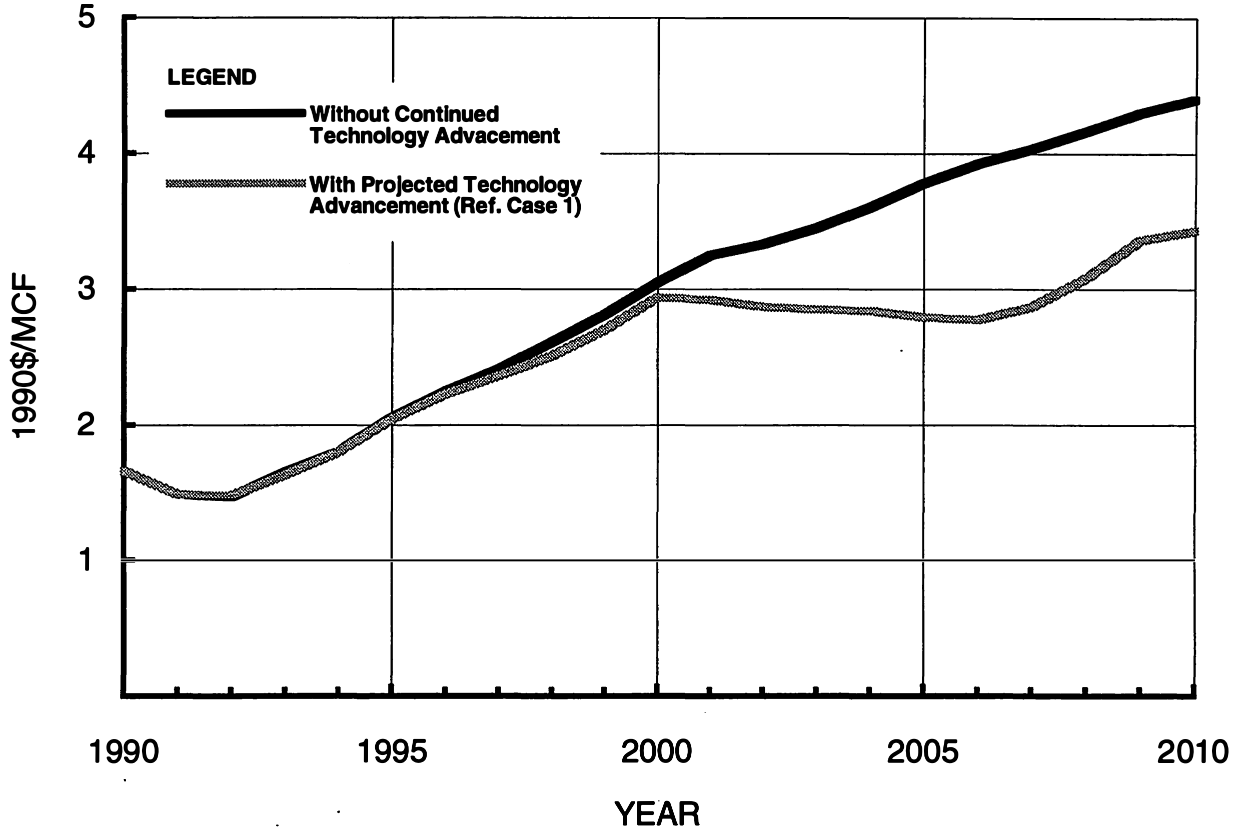

Figure 5-2. Technology Advancement Rate Impact on Wellhead Gas Price.

CHAPTER SIX

ENVIRONMENTAL AND ACCESS ISSUES

SUMMARY

The National Petroleum Council has examined the impacts of potential future environmental regulations and access limitations on the exploration and production (E&P) of natural gas. The results of this analysis demonstrate a clear potential to limit the ability of industry to increase the production of natural gas as an important resource in the national energy strategy. In addition, these same environmental regulations also have the potential to reduce the role that natural gas can play in solving the nation's air quality problem. Within this apparent dichotomy, the challenge is for industry and government to work together to solve the pressing environmental issues facing the E&P sector in a balanced and cost-effective manner, the opportunity is to sustain industry growth and improve air quality.

The methodology used to quantify these challenges and opportunities included:

1. Developing two environmental regulation scenarios to characterize the range of plausible future environmental regulation for the purposes of modeling a range of potential future economic impacts.
    - **Reference Scenario**: *A level of environmental regulation adequate to protect human health and the environment*, while balancing the costs and benefits of environmental regulations and recognizing the value of domestic natural gas production and end use. The analysis included a quantitative evaluation of the financial impact of potential additional future regulations, based upon a qualitative assessment of the level of regulation required to achieve environmental and economic balance. The result is Reference Scenario assumptions of compliance costs substantially above current requirements. These assumptions are incorporated in NPC Reference Cases 1 and 2.
    - **High Environmental Regulation Scenario**: A level of environmental regulation that represents a willingness to give up some level of gas supply to gain perceived environmental benefits, notwithstanding those benefits associated with increased gas use. Again the analysis included a quantitative evaluation of the financial impact of potential additional future regulations based upon a qualitative assessment of the level of regulation.
2. Developing cost estimates for compliance with anticipated regulations under the new Clean Air Act Amendments, the Safe Drinking Water Act, and pending Resource Conservation and Recovery Act and Clean Water Act reauthorizations.
3. Modeling the impacts of the High Environmental Regulation Scenario assumptions on both the NPC Reference Cases using the Hydrocarbon Supply Model.

The following are highlights of the cost and supply impacts that occur over the 20-year study period using Reference Case 1 (the moderate energy growth scenario) as an example (results for Reference Case 2 [the low energy growth scenario] are generally similar). These impacts represent the incremental costs and effects of the High Environmental Regulation Scenario over the Reference Scenario and demonstrate the potential costs and resource savings to be achieved if industry and government can work together to solve the pressing environmental issues in a balanced and cost-effective manner.

- A $35 billion increase in environmental compliance costs for the natural gas industry (including a 50 percent increase over today's costs for new wells in the lower-48 states).
- A 17 trillion cubic feet (TCF) reduction in cumulative natural gas production with annual reductions reaching 2 TCF (10 percent) in the year 2010.
- In addition, a significant portion of the resource base is already inaccessible due to leasing moratoria on the Outer Continental Shelf (OCS), restrictions in wilderness areas, marine sanctuaries, National Parks, Fish and Wildlife Service lands, and de facto administrative moratoria. The full potential of these areas will not be known until access is granted.

It is important to point out that even the Reference Scenario represents a 10 percent increase in new well costs onshore in the lower-48 states above today's already carefully controlled and monitored operations and is generally consistent with historical industry environmental expenditures.

The following recommendations to mitigate these potential impacts center around the central theme of bringing balance to the environmental legislative, regulatory, and permitting arenas by modifying government processes; revising industry research, advocacy, and outreach programs; and improving the public's education on the net environmental benefits of natural gas. More details on these recommendations can be found in Chapter Twelve.

Recommendations

1. Encourage government, at all levels, to create a balance between costs and benefits in the legislative and regulatory process for upstream environmental and access issues. This includes the direct recognition of the environmental benefits of natural gas as a clean-burning fuel.
2. Develop and supply timely and credible technical cost-benefit data for use in communication efforts with government, environmental groups, and the public. Focus research activities toward developing more cost-effective solutions to the environmental challenges facing the industry.
3. Enhance education programs to increase the public's understanding of the positive role natural gas can play in solving the nation's environmental problems. Target audiences include federal, state, and local governments, environmental organizations, and the general public.
4. Develop new innovative industry strategies to help better align industry's goals with the public's needs and expectations in order to create more timely and efficient solutions to environmental, permitting, and access issues (i.e., create win/win situations for industry; federal, state, and local governments; environmental groups; and the general public).

PURPOSE OF THE ENVIRONMENTAL REGULATIONS SUBGROUP

The purpose of the Environmental Regulations Subgroup was to identify and assess potential environmental constraints on future gas exploration and production. These constraints impose high compliance costs on operations and restrict access to the gas resource. The subgroup's activities fell into four categories:

- Identify and quantify possible environmental regulations and legislative initiatives on domestic gas E&P
- Model the costs and impacts of future environmental regulation scenarios on gas supplies
- Characterize environmental and access issues that could not be readily quantified for modeling purposes
- Analyze constraints and evaluate and recommend options for overcoming them.

HISTORICAL PERSPECTIVE AND TRENDS

Overview

Compliance with environmental regulations continues to be an ever increasing component of the costs to the natural gas E&P industry. Most of the early environmental regulations affecting E&P in the United States have contributed to improving the environment. However, more recent environmental regulations are controlling more aspects of oil and gas operations with increasingly complex and costly requirements while the corresponding environmental benefits are shrinking. In some cases requirements may have reached, and gone beyond, the point of diminishing returns, where the costs of achieving small increments of environmental improvement outweigh the benefits realized. In certain instances, compliance with regulations that protect one medium, like water, may affect the industry's ability to comply with regulations to protect other media, like land and air. Such cross-media effects are only beginning to be recognized by government regulators.

These factors highlight the need for a coherent government approach to environmental regulation to assess the cumulative effect of all environmental regulation on the industry. In addition, the need exists for a consistent uniform mechanism to adequately balance the upstream costs and benefits of these regulations with the downstream benefits of natural gas.

History of Environmental Regulation

Environmental Awareness

By the 1960s, a growing concern for water, air, and natural lands of the United States was growing into an awareness that uncontrolled discharges and emissions, urban and industrial growth, and development of, and reliance on, chemicals were taking a toll on the natural environment. Rachel Carson's *Silent Spring* documented the unintended effects of DDT and other pesticides on wildlife, particularly birds. In addition, there was a growing recognition that air quality had badly deteriorated in many cities, that many of the nation's major surface waters had severely deteriorated, and that our living spaces were encroaching on our natural surroundings. Esoteric terms like "environment" and "ecology" started as cult themes and then grew into a movement. An electorate outraged by environmental accidents and revelations like the Santa Barbara Channel oil spill, the Cuyahoga River fire, the Love Canal toxic waste dump, and the Three Mile Island nuclear reactor incident prompted waves of new federal and state laws to address pollution problems, real or perceived.

1970s: Decade of Environmental Legislation

An enormous number of federal and state environmental statutes were passed during the 1970s. One federal law that helped kick off this environmental decade was the National Environmental Policy Act of 1969 (NEPA). Unlike regulatory statutes that focus on water or air, NEPA required that federal agencies consider the environment in planning and undertaking federal projects and in permitting activities. The "NEPA process" requires preparation of analyses to assess the environmental impacts of federal actions or approvals. The NEPA process also created an unprecedented role for the public in reviewing actions and approvals of the federal government. This open window on federal decision making led to increased environmental litigation and legislation, and fueled the growth of environmental interest groups.

NEPA was followed in the 1970s by laws to protect air, water, wildlife, marine mammals, and drinking water; to regulate waste disposal, toxic chemicals, and coastal land use; and to set aside wilderness, sanctuary, and other areas off-limits to human encroachment. These laws are discussed in the Environmental Laws section later in this chapter. In most instances these laws set national standards for human health and environmental quality and put in place stringent new regulatory controls over industrial processes and wastes. This initial phase of legislation addressed the most obvious environmental problems and achieved significant environmental improvement at relatively reasonable costs.

Reauthorization of Environmental Laws

New major environmental legislation continued in the 1980s, but the emphasis shifted to legislative fine-tuning and new environmental regulations targeting second-generation issues with more specific and prescriptive requirements and corresponding increases in the cost of compliance. Many of these laws are scheduled to be reauthorized because existing authorities expire, and to adjust their requirements to correct continuing environmental problems. Unfortunately, these reauthorizations, which bring tougher, more expensive solutions, coincide with a time when the U.S. economy is in a period of sustained slow or no growth, foreign competition is strong, and the cold war military-industrial economy is in transition. It is essential that as laws are reauthorized, new provisions must balance the real environmental benefit gained with the cost of compliance. The example set by reauthorization of the Clean Air Act in 1990 was a case in point of Congress wielding an ax where a scalpel was needed. Future environmental legislation must be designed very carefully to create balanced costs and benefits if we are to preserve the U.S. industrial base.

Effects on the Oil and Gas Industry

Prior to the 1970s, oil and gas E&P activities were regulated primarily by the states and under certain federal statutes. With the implementation of new federal environmental initiatives, the cost of environmental compliance for E&P operations are estimated to have increased at about four percent annually.[1] In addition to the increase in compliance costs, new overhead costs were added as companies hired employees specifically to handle environmental permitting and compliance with new regulations. In the last decade, as domestic E&P programs and corresponding staffs were being reduced, the environmental staffs continued to grow.

Environmental Laws

In developing this report, the Environmental Regulations Subgroup examined a wide range of environmental laws that affect or may affect the domestic natural gas E&P industry. Some of the laws and regulations have specific requirements for which it is possible to develop compliance costs. These laws, regulations, and related environmental initiatives were used in the Hydrocarbon Supply Model to examine the effect of environmental requirements on compliance costs, the resource base, and natural gas E&P activity. This section briefly describes the laws used in the model, their requirements, and how they affect natural gas production. Many other laws and regulations are not as direct or predictable in how they affect the cost of producing natural gas or how they may affect industry's ability to access prospective acreage. These laws are listed at the end of this section and discussed in the final section of this chapter.

Laws Used in the Model [With Regulatory Requirements]

Major Laws Impacting E&P

Resource Conservation and Recovery Act (RCRA)

The RCRA of 1976 was the first federal attempt to address the management of solid and hazardous wastes and to promote conservation through waste recycling. Subtitle C of the Act is designed to provide cradle-to-grave management for hazardous waste generation, storage, transportation, treatment, and disposal. Subtitle D provides federal guidance to states in regulating non-hazardous wastes. Amendments to RCRA in 1984 added regulation of petroleum and hazardous wastes stored in underground tanks.

Congress exempted wastes associated with oil and gas operations from being categorized as hazardous wastes, subject to the Environmental Protection Agency (EPA) review of the need for regulating these wastes. A 1987 EPA report concluded that high volume, low toxicity oil and gas wastes did not need to be regulated under Subtitle C. Most of these wastes are regulated by individual states.

Future legislation may change how oil and gas wastes are treated. Reauthorization of RCRA may affect disposal of drilling muds and cuttings, the use of pits at drilling and production sites, and remedial cleanup of oil drilling sites. Of all the environmental regulations considered, RCRA has the greatest potential for increasing compliance costs on E&P operations.

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[1] American Petroleum Institute, *Environmental Expenditures of the United States Petroleum Industry, 1975-1984*, Publication No. 4404, 1985.

Clean Water Act (CWA)

Passed as the Federal Water Pollution Control Act of 1972, this statute's objective is to restore and maintain the chemical, physical, and biological integrity of the nation's waters. As amended in 1977 (which changed the name to Clean Water Act), the CWA establishes a system of effluent standards by industrial category, provides for a permitting system, sets waste water quality standards, provides for grants for municipal waste treatment, and addresses special issues like toxic wastes and oil spills. The authority for wetlands protection is contained in section 404 of the CWA, to be discussed in a later section. The CWA is scheduled to be reauthorized.

The effluent limitation standards and the National Pollutant Discharge Elimination System (NPDES) permit program are the chief regulatory tools under the authority of CWA. Effluent limitations are based on what is technologically achievable, not necessarily on the environmental benefit realized. Most of the effect of the CWA on natural gas E&P results from the NPDES program on offshore drilling and production.

Clean Air Act (CAA)

The first federal CAA, passed in 1967, established air quality standards, but the CAA of 1970 established a more comprehensive federal-state partnership for air pollution control. Health-based and general welfare-based ambient air quality standards are set at the federal level and states develop implementation plans to attain and maintain those standards. Though amended in 1977, the CAA amendments of 1990 add tough new measures for ozone nonattainment areas, provide for reduction of acid forming emissions, tighten up on mobile source emissions through additional emission controls and the use of reformulated and alternative fuels, set up a comprehensive permitting program, and create emission control standards for a new list of toxic emissions.

Natural gas E&P will be affected by temporary emission control requirements that may restrict construction and drilling emissions, and long-term emission control requirements for new, modified, or existing facilities (i.e., fugitive hydrocarbon emissions from field operations and gas plants). In areas that are not in attainment of ambient air quality standards, emission offsets may also need to be acquired.

Safe Drinking Water Act (SDWA)

The SDWA of 1984 established the Underground Injection Control (UIC) program to protect drinking water aquifers from contamination by subsurface injection of fluids. The Act required the EPA to establish minimum requirements for state programs or for federal primacy in the absence of state programs.

The UIC affects all underground injection associated with oil and gas exploration and production activities. Natural gas E&P may be affected by requirements for mechanical integrity testing of produced water injection wells. If fresh water aquifers are not being protected, then action may be required to correct the situation.

Other Laws Used in the Model

The following laws were used in the model to add compliance costs (Wetlands Protection) or were used in determining when resources in a hydrocarbon region would be available (OCS Moratoria). Both of these laws are also discussed at the end of this chapter, because they add unspecified costs and affect access.

Wetlands Protection

The authorities to protect wetlands come from the River and Harbors Act of 1899 and the CWA and cover both public and private lands. Though not clearly codified, the national policy of no net loss of wetlands can force activities to be restricted from, or severely modified within, a wetland area. The broadened definition of wetlands extends this protection to more areas.

Natural gas E&P activities may be forced to relocate to protect the wetland, and/or to mitigate impacts through replacement, enhancement, or creation of wetlands.

OCS Moratoria

Although the OCS program is administered by the Department of the Interior (DOI), since 1982 Congress has added language to the DOI budget appropriation every year placing certain offshore areas under leasing moratoria. Each appropriations statute has blocked leasing in the affected offshore area for one year. Beginning in 1984, Congress began blocking exploration activity on existing leases through the appropriations process.

Laws and Issues Not Included in the Model

Access to Public Lands

Much of the land within the United States is public property subject to federal control. This is especially true in the western states and Alaska. These lands are administered as specialized areas such as parks and monuments, wildlife refuges, wilderness areas, national forests, and other public lands. Wilderness areas, parks and monuments, and some wildlife refuges are not available for oil and gas E&P. National forests and other public lands, however, may be available for oil and gas E&P, but are often restricted. Mineral rights and E&P authorizations on these lands are administered by federal land management agencies and are subject to laws and public decision making processes that may not apply on private lands.

The Outer Continental Shelf is another specialized area under federal jurisdiction and subject to federal environmental laws. Parts of the OCS and adjacent state waters are set aside as marine or estuarine sanctuaries and may be off limits to oil and gas E&P. A separate section of this report addresses specific land access issues.

Initiatives that Affect E&P Costs and Access

There are other laws or initiatives that add to the cost of domestic gas E&P by causing delays or requiring site specific mitigation measures. Also, certain laws may block or limit access to public and private lands and the OCS. In some cases the laws do not absolutely prohibit activities, but may make them so controlled or costly as to be impractical or uneconomical.

The following environmental statutes and issues fall into this category and are considered in more detail at the end of this chapter.

- Coastal Zone Management Act of 1972
- Marine Sanctuary Program (Marine Protection, Research, and Sanctuaries Act of 1972)
- Marine Mammal Protection Act of 1972
- Endangered Species Act of 1972
- Wetlands Protection (Clean Water Act 1977)
- Comprehensive Environmental Response, Compensation, and Liability Act of 1980; and Superfund Amendments and Reauthorization Act of 1986
- Oil Pollution Act of 1990
- Toxic Substances Control Act of 1976
- Naturally Occurring Radioactive Material.

Environmental Trends in the 1990s and Beyond

Although the pace of new environmental legislation and regulation varies, the discernible trend is for continued development of new environmental initiatives. The implication is that the incremental cost of environmental compliance for the domestic natural gas E&P industry will grow throughout the study period. In contrast, there are positive signs that natural gas, because of its environmental benefits as a fuel, may increasingly become the fuel of choice.

Some of the ongoing political processes and issues that will affect environmental initiatives include:

Law Versus Litigation. Rather than litigating on specific environmental issues in the courts, environmental groups are using their political clout directly with members of Congress to achieve their goals through legislation. Environmental litigation will not go away, but the prospects are for more environmental laws, addressing smaller issues, with greater specificity in the requirements spelled out in law, and with a corresponding increase in costs for industry.

Ecological Protection and Bio-Diversity. A very clear trend in environmental law and regulation will be the focus on ecological protection rather than just protecting individual resources. This more holistic approach is being promoted to protect ecological systems and to preserve, for scientific research and study, all of the lifeforms in those systems.

Naturally Occurring Radioactive Material (NORM). Disposal of NORM wastes, those scales and sludges contaminated by low levels of radium from subsurface formations, is not a new issue. At this writing, however, the regulatory strategies have not been developed to address handling and disposal of NORM contaminated wastes and oil field hardware.

Natural Gas as an Environmental Fuel. Natural gas is recognized as the cleanest burning hydrocarbon fuel and it may find more use in both traditional and non-traditional applications. Gas is also relatively benign to produce and transport.

Energy Conservation/Alternative Fuels. An issue in the debate on domestic oil and gas drilling is the broader issue of energy conservation and the use of other fuels to replace non-renewable hydrocarbons. There will likely be continuing efforts to decrease U.S. dependence on, and demand for, oil and even gas as fuels.

Global Climate Change. Global climate change caused by the gradual buildup of carbon dioxide, methane, and other greenhouse gases is an issue of growing public policy and scientific debate. As the debate continues, it may serve as a driving force for legislation and regulation to minimize the consumption of fossil fuels with preference given to those fossil fuels that minimize the emission of these gases. Natural gas is the lowest emitter of combustion carbon dioxide, but it is itself a greenhouse gas, which may draw attention to minimizing emissions from transportation and storage.

DESCRIPTION OF METHODOLOGY AND ASSUMPTIONS

The analyses performed by the Environmental Regulations Subgroup were intended to assist the NPC in assessing the potential impact of environmental compliance requirements on future gas supplies. This involved incorporating into the Hydrocarbon Supply Model compliance cost data developed by the American Petroleum Institute (API), the U.S. Department of Energy (DOE), and others concerning a variety of initiatives affecting domestic oil and gas E&P operations. This section defines and describes the environmental regulatory scenarios analyzed, the sources of data and methodology used to estimate the costs of compliance associated with each scenario, and the impacts of these compliance requirements on the costs of gas supply.

Definition of Scenarios

For purposes of examining the impact of potential environmental regulatory requirements on future gas supplies, two regulatory scenarios were assumed, as defined below:

- **Reference Scenario.** The environmental compliance costs developed for this scenario are intended to represent a "balanced" future regulatory scenario appropriate for the reference-case model runs. Specifically, this scenario represents *a level of environmental regulation adequate to protect human health and the environment*, balancing the costs and benefits of environmental regulations and recognizing the value of domestic natural gas production and use (a low economic impact case). The analysis included a quantitative evaluation of the financial impact of potential additional future regulations, based upon a qualitative assessment of the level of regulation required to achieve environmental and economic balance. The result is a scenario with compliance costs substantially above current requirements but well below the High Environmental Regulation Scenario discussed below. This scenario also recognizes that a "balanced" regulatory approach allows states to retain regulatory primacy under the authority of the various environmental statutes considered.
- **High Environmental Regulation Scenario.** The environmental compliance costs developed for this more stringent scenario are intended to correspond to a level of environmental regulation which represents a willingness to give up some level of gas supply to gain perceived environmental benefits, notwithstanding those benefits associated with increased gas use (a high economic impact case). The philosophy of this scenario is that domestic gas production is important, but assumes that national policy will continue to press for increased environmental protection for the foreseeable future. Thus, natural gas E&P activities will be subject to increasing levels of environmental regulation under this scenario. This represents those initiatives that have been publicly proposed or considered but does not represent a highest cost scenario for

those initiatives. In addition, the final section of this chapter discusses the issues and initiatives not costed or modeled in this analysis. Again, the analysis included a quantitative evaluation of the financial impact of potential additional future regulations based upon a qualitative assessment of the level of regulation.

These regulatory scenarios do not necessarily represent any set of requirements recommended or supported by the EPA or any other federal or state agency. In addition, these scenarios or specific requirements are not recommended by any specific association, company, or institution. These scenarios are only intended to represent a range of stringency, corresponding to options that have been under consideration or discussion.

The methodology and assumptions used to develop and represent the incremental costs of environmental compliance associated with each scenario are discussed in more detail in the following sections.

Methodology for Estimating Incremental Environmental Compliance Costs

Sources of Environmental Compliance Cost Data

The development of the costs associated with the defined regulatory scenarios involved a review of numerous environmental initiatives that could affect U.S. natural gas E&P. Potential initiatives under a variety of environmental statutes were reviewed. However, sufficient data on estimated potential costs of compliance, for purposes of modeling the impacts of compliance, could only be developed for four major environmental statutes: Resource Conservation and Recovery Act, Safe Drinking Water Act, Clean Water Act, and Clean Air Act. These four statutes are believed to represent the majority of the financial impacts affecting natural gas E&P operations from 1992 to 1996.

The costing data used in this analysis primarily came from two sources. First, API has developed estimates of the potential impacts of possible RCRA Reauthorization initiatives on current oil and gas supplies. These estimates, developed by Gruy Engineering,[2] corresponded to the potential cost impacts of RCRA Reauthorization legislation proposed in 1991. Second, in January 1990, ICF Resources published a report[3] in which over 20 individual environmental initiatives were examined, with explicit compliance cost estimates developed to correspond to the requirements that could be associated with each initiative. Unfortunately, the DOE analysis looked only at the impact of these initiatives on crude oil E&P. Therefore, it was necessary to identify and develop the potential environmental compliance costs associated with natural gas E&P. While the DOE and API studies were extensively referenced, substantial modifications and upgrades were made in these estimates to more appropriately and accurately incorporate them into this analysis.

Methodology for Determining Incremental Environmental Compliance Costs

From a review of the various sources of potential compliance cost data, a number of compliance options were developed for various regulatory initiatives, defined in terms of the explicit steps operators would have to take to bring various field-level operations and practices into compliance. For each operation or practice, an array or matrix of possible compliance options was developed, each corresponding to a specific regulatory initiative. For each of the two defined regulatory scenarios, consensus was reached among members of the Environmental Regulations Subgroup in consultation with their in-house environmental experts for each operation or practice that was most appropriate for the scenario.

From the compliance options selected by the subgroup members, detailed estimates of the compliance costs associated with each initiative were developed, using the previously

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[2] Gruy Engineering Corp., *Estimates of RCRA Reauthorization Economic Impacts on the Petroleum Extraction Industry*, prepared for the American Petroleum Institute, July 1991.

[3] ICF Resources Incorporated, *Potential Cumulative Impacts of Environmental Regulatory Initiatives on U.S. Crude Oil Exploration and Production*, prepared for U.S. Department of Energy, Office of Planning and Environment, December 1990.

collected data as a basis. A report documenting these estimates was developed by ICF Resources, a contractor to the NPC, for both regulatory scenarios. (These reports are available as Subgroup Working Papers from the National Petroleum Council.) These reports were reviewed by each member's in-house experts, who recommended numerous modifications which were then incorporated into the cost estimates as appropriate.

For each regulatory scenario, compliance costs were developed that were associated with both existing and new wells or facilities. Existing facilities or wells refer to those operating at the time the regulations are assumed to be implemented. New facilities or wells are those that would be put into future operation according to the development schedules assumed in the Hydrocarbon Supply Model. Where no distinction is made between existing or new facilities, the incremental compliance costs apply to both.

In addition, because of the unique impact of increased compliance costs on producers in Appalachia, a group of Appalachian oil and gas producers were asked to review the cost assumptions for Appalachian operations. These reviewers recommended numerous modifications that would better represent potential compliance costs associated with operations in their region. Where appropriate, these recommendations were incorporated into the compliance costs estimates for each scenario.

Thus, each regulatory scenario was defined in terms of the set of initiatives specified by the subgroup, with the costs associated with the individual initiatives explicitly determined. For each of the scenarios, the new environmental requirements were assumed to be fully promulgated and in place by 1996, phasing in uniformly over a five-year period. This was done to approximate the timing of implementation for the initiatives considered.

While the capital and operating cost impacts of various environmental and other regulatory requirements were developed in a considerable amount of region- and resource-specific detail for explicit operations and practices, the additional administrative costs to industry of these environmental requirements were not specified in detail. This does not suggest that these costs are insignificant. The administrative burden, in fact, is thought to be high. However, in the absence of definitive data to specifically describe these costs, the same "overhead" factor that relates other administrative costs to capital and operating expenditures was used. Thus, regulatory administrative costs are assumed to increase proportionally with increasing compliance-related capital and operating expenses.

In the Reference Scenario, after 1996, no new regulatory requirements were modeled, and therefore no further increases in compliance costs were assumed over the remaining years of analysis. This scenario represents a "balanced" case where any incremental environmental compliance costs are offset by technology advances.

The High (more stringent) Environmental Regulation Scenario, on the other hand, assumes that the specified set of regulatory compliance requirements are in place by 1996, with their corresponding increased costs of environmental compliance, and that environmental requirements continue to evolve and become more stringent, with the incremental costs of environmental compliance continuing to increase at a real rate of 4 percent per year. This annual rate of increase is based on a review of environmental compliance expenditures over the last 15 years. For example, until 1984, API conducted an annual survey of environmental expenditures by the petroleum industry, summarizing compliance cost trends for E&P operations over the years from 1975 to 1984.[4] During this period, many new federal environmental requirements were developed, and others were substantially strengthened, leading to an annual average growth rate in compliance costs for E&P operations, after adjusting for inflation and activity levels, of 3 to 5 percent per year.

Environmental compliance costs specific to E&P are not available for the late 1980s, but it is reasonable to assume that they followed national trends. Pollution Abatement and Control Expenditures surveys, covering manufacturing operations and published periodically in the Survey of Current Business, indicate that total pollution control expenditures increased at a

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[4] American Petroleum Institute, *Environmental Expenditures of the United States Petroleum Industry, 1975-1984*, Publication No. 4404, 1985.

real rate of around 3 percent per year from 1984 to 1988. EPA has estimated that total environmental expenditures grew at a real rate of 6 to 8 percent per year during the late 1980s. EPA has also made estimates of future environmental compliance cost trends, projecting that total national environmental expenditures will increase at a real rate of 4 to 6 percent per year through 2000.[5]

Description of Environmental Regulation Scenarios

The compliance options selected to correspond to the philosophy of each defined regulatory scenario resulted in a set of specific practices and operations (and corresponding costs) consistent with that scenario. Under the Reference Scenario, distinct regulatory objectives were assumed under each of the major environmental statutes impacting domestic oil and gas E&P operations. Specifically, the following objectives were assumed:

- Under RCRA, the existing exemption of oil and gas E&P wastes was assumed to be continued, and states were assumed to retain their regulatory authority over E&P wastes, but some improvements in state programs were assumed to be implemented. These included improved controls for the management and disposal of drilling wastes, required off-site disposal of other associated wastes (other than drilling wastes and produced water), further controls on pits at oil and gas E&P sites (lined emergency pits, no workover or evaporation/blowdown pits), and required testing of E&P wastes.
- Under SDWA, improvements in existing UIC programs were assumed that would require more frequent mechanical integrity testing for injection wells, with the requirements for wells originally permitted by rule allowed to continue.
- Under CWA, EPA's 1991 proposed rule for the discharge of drilling wastes from offshore platforms was assumed to be promulgated, with EPA's forecast of potential impacts assumed to be accurate. The requirements under the proposed rule for treating produced water discharges were assumed to be unjustifiably stringent, and somewhat less stringent requirements were assumed. Existing rules for storm water discharges and for discharges to coastal waters were assumed to remain in place, and further restrictions on operations in wetlands were assumed to take effect. No new requirements for other surface discharges (such as for stripper wells or beneficial use) or further requirements for aboveground storage tanks were assumed to be enacted.
- Under CAA, the 1990 amendments were assumed to impact E&P operations in two ways: all onshore operations were assumed to meet standards similar to those currently required in California ozone nonattainment areas; and offshore areas adjacent to corresponding onshore areas that are in nonattainment for ozone must install stringent controls, but will not be required to acquire emission offsets.

Similarly, under the High Environmental Regulation Scenario, the following regulatory objectives were assumed to be consistent with the philosophy of the scenario, for each of the major environmental statutes considered:

- Under RCRA, regulatory requirements consistent with those proposed by Sen. Baucus (D-MT) in 1991 (S.976) were assumed to be enacted. These would require that all surface impoundments (pits) have double liners, leachate collection systems, and groundwater monitoring. For most situations, tanks were assumed to be more cost-effective than pits under the specifications of the proposed legislation. All E&P facilities were assumed to require permits similar to those currently required under RCRA Subtitle C for hazardous waste facilities, with their corresponding permit fees, site investigation, and potential remediation requirements.
- Under SDWA, more stringent mechanical integrity testing requirements were assumed under existing UIC programs, with more frequent testing and a greater variety of tests required. Moreover, the current exemptions for wells permitted by rule were assumed to be revoked, requiring that operators of these older wells

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[5] Environmental Protection Agency, *Environmental Investments: The Cost of a Clean Environment*, EPA-230-12-90-084, December 1990.

perform area of review assessments and take corrective action where necessary, and that some older wells would require additional work to meet current construction standards.

- Under CWA, EPA's 1991 proposed rule for offshore discharges was assumed to be promulgated in final form, and the forecast impacts of API were assumed to result. Current requirements for storm water discharges were assumed to continue, with all other discharges of E&P wastes to surface waters prohibited. More stringent requirements for aboveground storage tanks and operations in wetlands were also assumed.
- Under CAA, the second-phase residual risk provisions as enacted in the 1990 amendments were assumed to require that onshore E&P facilities install substantially more stringent controls for air emissions, including some controls that are currently still in their experimental stages. Strict control requirements were also assumed for offshore E&P facilities, with those operations in nonattainment areas required to acquire emission offsets.

Neither scenario considered every potential regulatory initiative that may affect the economics of U.S. E&P activities, nor do they include the most stringent requirements for the initiatives considered. The estimated compliance costs associated with many initiatives have not been assessed (see discussion in the last section of this chapter). In addition, the regulatory initiatives proposed or under consideration are constantly evolving; this study represents only the initiatives under consideration at the time of the analyses. Since it does not consider all regulations potentially impacting U.S. gas supplies, the results of the assessment could be considered somewhat conservative.

Since the analysis focused primarily on federal environmental requirements, the assessment uniformly assumes that the regulatory initiatives considered are, for the most part, applied nationwide. In specific situations (e.g., coastal, wetlands, or offshore areas), some distinction among acceptable potential compliance practices by region, resource, recovery process, or site-specific conditions was assumed. However, if more site-specific, risk-based environmental regulations are implemented with the primary regulatory authority remaining at the state level, the impacts could be different than those estimated in this analysis.

Appendix K of this volume includes a number of tables to illustrate and document various aspects of cost and impact. In addition, detailed regional breakdowns are available in Subgroup Working Papers from the National Petroleum Council.

The specific regulatory compliance initiatives considered under each scenario are summarized in Table 1 of Appendix K, with the explicit representation of the costs associated with these initiatives summarized for each scenario in Table 2.

Estimated incremental environmental compliance costs associated with each scenario were specifically developed for each region and depth category in the Hydrocarbon Supply Model. These costs were determined for both existing and new wells. Moreover, where resource-specific distinctions were included (such as that associated with coalbed methane production), the estimated compliance costs reflect that distinction. Finally, distinctions were also made for stripper and nonstripper wells, where appropriate. To appreciate the impact of the increased costs of compliance associated with each scenario on the costs of gas E&P, it is useful to compare the costs of an average or representative gas well to its estimated incremental compliance costs. For the Reference Scenario, representative or average initial incremental compliance costs are illustrated in Table 3 of Appendix K for a typical lower-48 onshore gas well, with representative incremental annual operating costs shown in Table 4. Similarly, Tables 5 and 6 of Appendix K show representative costs for the High Environmental Regulation Scenario for initial and annual costs, respectively. Estimated incremental compliance costs for a representative offshore lower-48 gas well under the Reference Scenario are shown in Tables 7 and 8 of Appendix K, with the corresponding representative costs under the High Environmental Regulation Scenario presented in Tables 9 and 10.

Representative or average costs for gas well drilling costs are published annually by

API.[6] Similarly, the Energy Information Administration regularly publishes data on average equipment and operating costs.[7] From this data, representative costs for a "typical" lower-48 onshore gas well are as follows:

Drilling, Completion, and Well Equipment	$396,000
Lease Equipment	$41,200
Operations and Maintenance	$20,000/year

Similarly, costs for a "typical" offshore gas well in the Gulf of Mexico are represented as follows:

Drilling, Completion, and Well Equipment	$3,800,000
Platform Operations	$194,387/well/year

In reality, the estimated incremental compliance costs assumed under each scenario varied considerably by region and depth, as shown in more detail in the next section. Nonetheless, under the Reference Scenario, the average increases in costs associated with "typical" gas wells are summarized in Table 6-1.

Similarly, the average increases in costs associated with "typical" gas wells under the High Environmental Regulation Scenario in 1997 are summarized in Table 6-2. It is important to note that under the High Environmental Regulation Scenario costs continue to escalate past 1997 at an average of 4 percent per year (offset by a 2 to 3 percent per year improvement in technology and other factors) until the year 2010 the initial well cost shown in Table 6-2 to approximately 50 percent.

TABLE 6-1

COSTS ASSOCIATED WITH TYPICAL GAS WELLS REFERENCE SCENARIO

Well Cost Category	Percent Increase Over Baseline
Lower-48 Onshore Gas Wells	
New Wells	
Initial Cost	10.5%
Annual Cost	13%
Existing Wells	
One-time Cost	98%*
Annual Cost	10%
Lower-48 Offshore Gas Wells	
New Wells	
Initial Cost	2%
Annual Cost	4%
Existing Wells	
One-time Cost	—
Annual Cost	—

* One-time cost increase presented relative to normal annual operating and maintenance costs.

However, as stated above, each region and depth zone (Hydrocarbon Supply Model cell) in the Hydrocarbon Supply Model has individual compliance cost estimates for each initiative. Some cells have more significant costs associated with natural gas E&P due to estimates of current operational practices that would have to be modified under the environmental regulation scenarios. The compounding effect of several regulations varies considerably by region, as shown in Figure 6-1. This figure shows seven onshore hydrocarbon cells as examples, with their incremental compliance costs in the Reference Scenario. Costs are represented on a per well basis. For example, wells drilled at depths greater than 15,000 feet in South Louisiana (depth 4) have the largest incremental drilling costs, and must therefore, drill for prospects large enough to offset these higher costs in order to remain competitive with wells in other regions and depth categories.

Relative to baseline costs, the lower-48 onshore regions—experiencing the greatest potential increase in drilling and completion (D&C) costs under the Reference Scenario—

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[6] American Petroleum Institute, *1990 Joint Association Survey on Drilling Costs*, 1991.

[7] Energy Information Administration, *Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations, 1987-1989*, 1990.

TABLE 6-2

COSTS ASSOCIATED WITH TYPICAL GAS WELLS HIGH ENVIRONMENTAL REGULATION SCENARIO

Well Cost Category	Percent Increase Over Baseline
Lower-48 Onshore Gas Wells	
New Wells	
Initial Cost	26%
Annual Cost	19%
Existing Wells	
One-time Cost	319%*
Annual Cost	21%
Lower-48 Offshore Gas Wells	
New Wells	
Initial Cost	27%
Annual Cost	17%
Existing Wells	
One-time Cost	30%*
Annual Cost	2%

*** One-time cost increase presented relative to normal annual operating and maintenance costs.**

are as follows (for shallow wells less than 5,000 feet deep):

South Louisiana (E)	31%
Williston Basin (WL)	24%
Eastern Gulf (B)	18%
Arkla-East Texas (D)	14%
Texas Gulf (G)	14%

The High Environmental Regulation Scenario has significant cost impact on the same regions (Figure 6-2). These costs are generally two to three times the costs for the same region in the Reference Scenario.

Relative to baseline costs, the lower-48 onshore regions—the regions experiencing the greatest increase in D&C costs under the High Environmental Regulation Scenario—are as follows (for shallow wells less than 5,000 feet deep):

South Louisiana (E)	107%
Williston Basin (WL)	84%
Texas Gulf (G)	49%
Arkla-East Texas (D)	48%
Eastern Gulf (B)	38%

Within the Hydrocarbon Supply Model, however, it is assumed that technology will improve to reduce overall D&C costs (environmental compliance cost included) by 2 percent per year (see Chapter Five). Without the impact of technology, D&C costs in 2010 under the High Environmental Regulation Scenario, given the 4 percent per year escalation factor, would be over 50 percent higher than costs in 1996 due to the increased costs of environmental compliance. However, given the impacts of technology improvements assumed, total D&C costs are only 16 percent higher in 2010 than in 1996.

The differences in costs for the offshore regions are even more dramatic. Figures 6-3 and 6-4 show near ten fold increases in environmental costs associated with drilling in many of the offshore regions when comparing the Reference Scenario to the High Environmental Regulation Scenario. In the Gulf of Mexico Continental Shelf, this results in a 30 to 40 percent increase in total new well D&C costs, and in the Pacific region costs increase by 80 percent. In the Reference Scenario, CWA accounts for most of the incremental cost offshore except in the Pacific, where CAA is very significant as well. In the High Environmental Regulation Scenario, CAA accounts for most of the incremental compliance costs.

OCS Timing Assumptions and Distribution of Undiscovered Resources

A set of availability and timing assumptions for the development of resources by OCS planning area was also developed. The suggested schedule includes both a date for leasing and a lag time before exploration begins (see Table 11 in Appendix K). This lag reflected the time needed to complete environmental impact

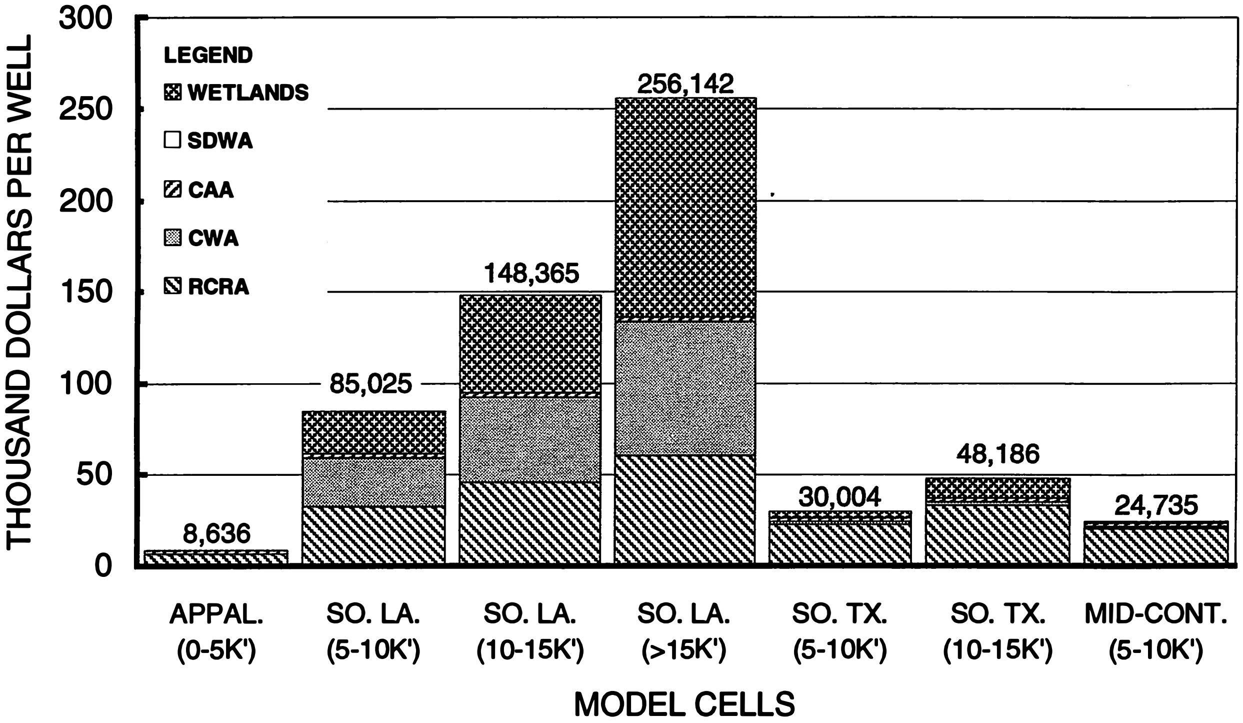

Figure 6-1. Environmental Compliance Costs for Drilling and Completion of New Gas Wells in Onshore Regions Reference Scenario.

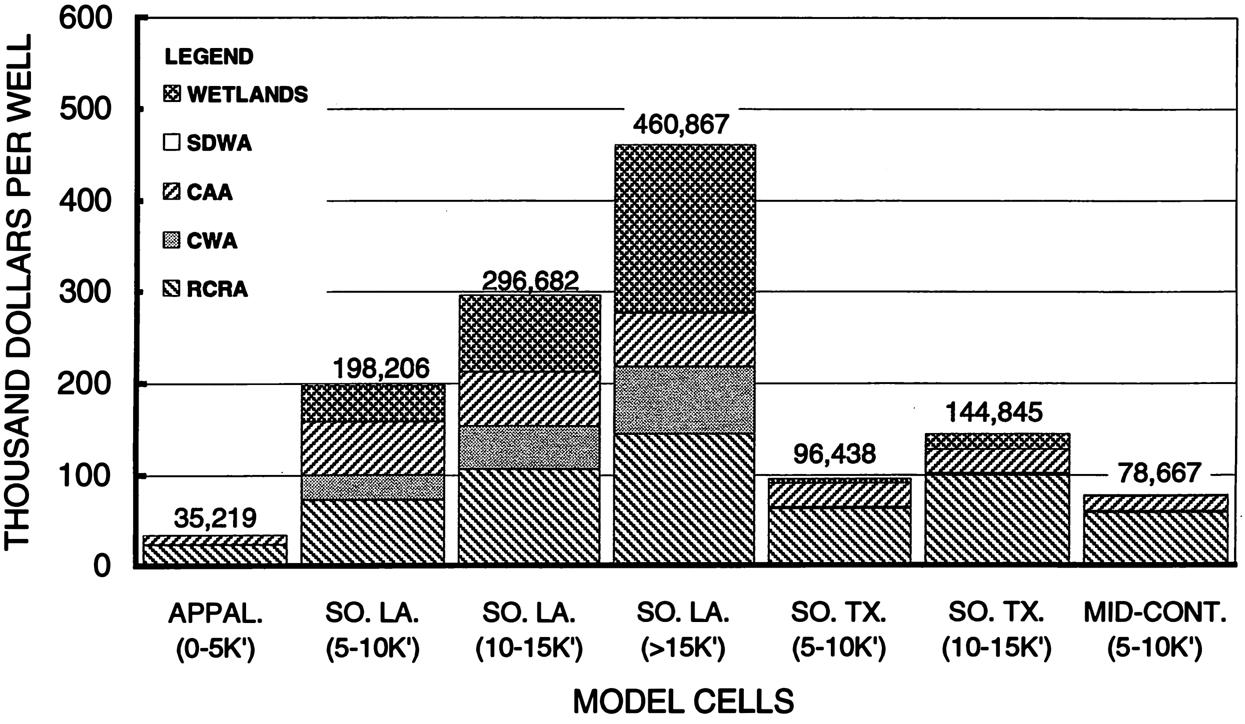

Figure 6-2. Environmental Compliance Costs for Drilling and Completion of New Gas Wells in Onshore Regions High Environmental Regulation Scenario.

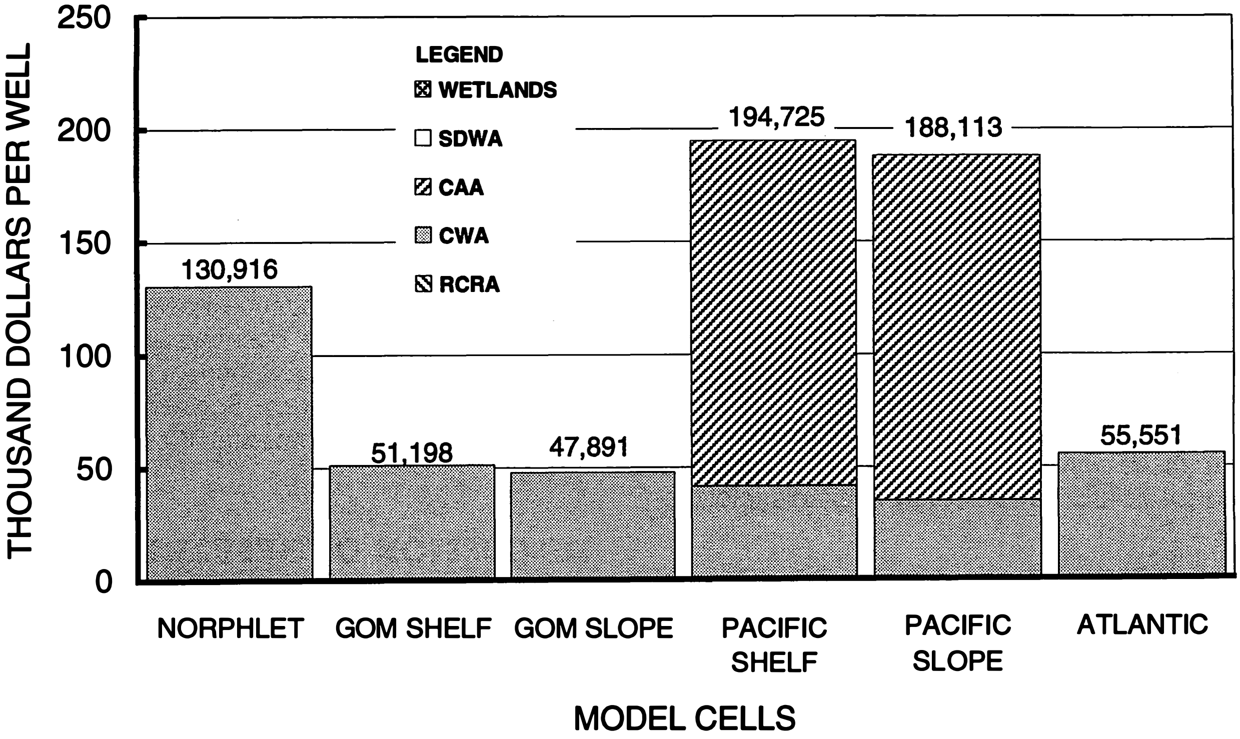

Figure 6-3. Environmental Compliance Costs for Drilling and Completion of New Gas Wells in Offshore Regions Reference Scenario.

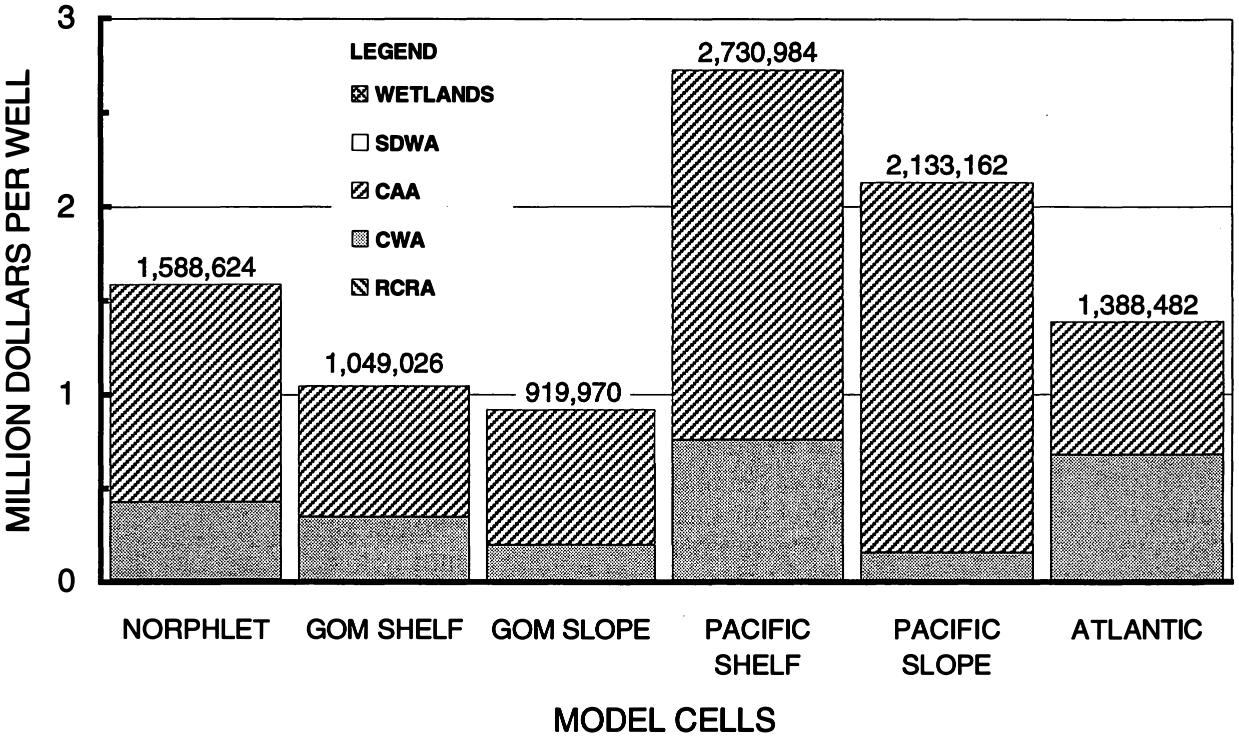

Figure 6-4. Environmental Compliance Costs for Drilling and Completion of New Gas Wells in Offshore Regions High Environmental Regulation Scenario.

statements, obtain permits, and other delays prior to drilling the first exploratory wells. This schedule was developed based on current Presidential and Congressional moratoria, as well as the Minerals Management Service's Five-Year Leasing Plan for 1992-1997. In some areas, leasing was assumed to be delayed beyond the end of current moratoria, based on current strong opposition in Congress and in coastal communities to the leasing of these areas, along with accounting for the difficulty that may occur in obtaining permits. This schedule represents the best estimation of when these resources might be developed and produced based on currently available information.

In addition, some analysis was performed on onshore lands that are currently unavailable for leasing. These lands are those associated with wilderness areas, other federally owned lands, and native and Indian lands. However, as discussed in more detail in the final section of this chapter, this analysis was not included in the model.

Inputs to Model

The Hydrocarbon Supply Model is divided into a number of onshore and offshore regions (see EEA Guide to Hydrocarbon Model). Each region is in turn divided into three or four drilling depth ranges. Each of these region/depth pairs is known as a cell.

All of the environmental regulatory initiatives have had costs assigned for each region based on equations that take into account all variables critical to properly defining the cost of each initiative. Detailed regional and depth breakdowns are available from Subgroup Working Papers for both the Reference Scenario and the High Environmental Regulation Scenario. All regulatory compliance costs are input in a dollar per well format for each of the depth cells in the model. These costs are represented explicitly as both D&C costs during the drilling phase, and operating and maintenance (O&M) expenses during production.

In order to fulfill the input requirements of the Hydrocarbon Supply Model, costs were input for both oil and gas wells. In addition, incremental compliance cost estimates vary depending on the type of oil or gas well in each cell (i.e., new gas wells, old gas wells, coalbed methane, tight gas sands, etc.).

Tables in Appendix K for the Reference Scenario and tables in the Environmental Working Papers show the compliance costs by region and depth category for each of the various initiatives. In addition, they illustrate the costs for various types of wells. Tables showing these same compliance costs as the percentage increase over baseline D&C or O&M costs, for the Reference Scenario and High Environmental Regulation Scenarios, are included in the Environmental Working Papers as well.

DISCUSSION OF RESULTS

Introduction

The purpose of modeling environmental regulatory compliance scenarios was to assist in understanding the relative impacts of the High Environmental Regulation Scenario over the Reference Scenario. The incremental impact, or "Delta," between the High Environmental Regulation Scenario and the Reference Scenario is useful to demonstrate the need to change the current direction of environmental legislation and regulation on the upstream natural gas industry. Reducing this incremental impact can also be seen as an opportunity to improve the outlook for domestic natural gas E&P.

The modeling methodology used to isolate the impacts on the upstream natural gas industry is best described as a reserve impact approach. Using the Hydrocarbon Supply Model[8] the price and demand forecasts were fixed, allowing supply to respond to price. This approach helped isolate the impacts on the upstream industry. Of course in reality, as production declined, prices would rise, and therefore not all of the production would be lost. The consumer, nonetheless, would pay higher prices to offset some of the potential supply loss, or switch to less costly alternatives.

The following categories of impacts were assessed:

- ***Impact on Costs.*** The incremental cost impact on industry is an important cate-

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[8] See *Guide to the Hydrocarbon Model*, Energy and Environmental Analysis, Inc., 1992.

gory to review in that it describes the capital that industry would need to invest under the High Environmental Regulation Scenario over and above their investment level in the Reference Scenario environment. Requiring these investments is likely to reduce drilling and other reinvestment.

- ***Impact on Production.*** The impact on production is a direct measure of the potential reduced production due to high environmental regulation compliance costs. Since drilling and operating costs are higher in the High Environmental Regulation Scenario, fewer wells are drilled, resulting in less reserves being discovered. In addition, production is reduced when more wells are abandoned prematurely as they become uneconomic to produce.
- ***Impact on Abandonment of Existing Wells.*** As additional compliance costs are required, some currently marginal production wells will be prematurely abandoned due to their uneconomic nature. This means that production, jobs, and revenues for both the private and public sectors will be reduced.

For each category of impacts, the results of the analysis were presented both annually and cumulatively, where the cumulative impact represents impacts that incurred over the 1992 to 2010 time period.

In order to best describe the impact of future environmental regulations under various market conditions, the compliance scenarios were analyzed under two different energy demand and economic growth cases. These cases are known as NPC Reference Case 1 and NPC Reference Case 2. In general, Reference Case 2 is a low growth, low demand scenario, where prices reach approximately $2.50 per thousand cubic feet by 2010. Reference Case 1 is a moderate growth/demand case in which prices grow to about $3.50 per thousand cubic feet by 2010.

Since each of the environmental regulation scenarios was analyzed under each of the Reference Cases, a total of four output cases were generated. These are described below by concentrating on the incremental impact, or delta, between the environmental regulation scenarios for each of the Reference Cases. A number of additional tables detailing these impacts are included in Appendix K.

Industry Cost Impact

One measure of the impact of the regulatory scenarios on industry is the cost of environmental compliance. Adding costs to the industry reduces the number of wells drilled, as some projects of marginal profitability become uneconomic due to the higher cost burden. Adding costs to the industry also reduces the capital available for reinvestment with the effect of further reducing drilling activity. In actuality, the environmental compliance costs added to the natural gas E&P industry are what cause the impacts described in the other two categories of impacts, which are discussed in more detail in the following section.

Total Compliance Costs

Compliance cost on the upstream oil and gas industry is significant in that it represents the total incremental capital outlay that industry would expend under the High Environmental Regulation Scenario, relative to that in the Reference Scenario. This will limit reinvestment in natural gas drilling and development projects significantly. This reinvestment impact was not explicitly addressed in the model, since it was assumed that investors would not limit reinvestment capital in total, or as a percent of the prior years revenue, strictly due to environmental compliance costs. Impacts modeled, therefore, may be somewhat underestimated.

Reference Case 1

Much of the upstream gas industry is integrated with the oil industry. In some basins, industry looks for hydrocarbons and has a limited ability to distinguish between oil and gas before drilling. Compliance costs on both oil and gas, therefore, have a significant impact on the upstream natural gas industry. The total incremental cost to the oil and gas E&P industry for the High Environmental Regulation Scenario is $86 billion over that in the Reference Scenario under this Reference Case.

The cumulative incremental compliance cost to industry for the 1992-2010 period under the Reference Scenario totals $35 billion, while that under the High Environmental Regulation Scenario is $122 billion.

Reference Case 2

Under Reference Case 2, the cumulative compliance cost to industry during the 1992-2010 period under the Reference Scenario totals $30 billion, while under the High Environmental Regulation Scenario the cumulative total equals $101 billion, yielding an impact delta of $71 billion.

To put these costs in perspective, the E&P industry currently expends an estimated two to three billion dollars annually to comply with environmental regulatory requirements.[9] All costs under both scenarios discussed above are incremental to current expenditures.

Natural Gas Compliance Costs

A subset of these compliance costs are the estimated costs for natural gas wells. Compliance costs associated with gas wells only (i.e., excluding oil wells from the totals above) are very significant in the High Environmental Regulation Scenario, when compared to the Reference Scenario.

Reference Case 1

The cumulative incremental cost to comply in the high environmental scenario, relative to the Reference Scenario, is $35 billion, as shown in Figure 6-5, which illustrates both Reference Scenario and high regulatory compliance costs through time for gas under Reference Case 1.

The cumulative compliance cost to industry for the 1992-2010 period under the Reference Scenario totals $12 billion, while under the High Environmental Regulation Scenario, the cumulative total equals $47 billion. Annual compliance costs reach over $3.5 billion in the high environmental scenario, whereas they are less than $750 million per year in the Reference Scenario.

Reference Case 2

Under Reference Case 2, the cumulative compliance cost to industry over the 1992-2010 time period under the Reference Scenario totals $10 billion (Figure 6-6), while under the High Environmental Regulation Scenario the cumulative total equals $40 billion, yielding an impact delta of $30 billion over the Reference Scenario.

Under either Reference Case, the incremental compliance costs are significant. It is relatively easy to imagine a number of quality natural gas investments being uneconomic with industry spending an additional $30 to $35 billion on compliance costs.

Production Impact

Decreases in production due to high environmental compliance costs will impact the nation's natural gas supply. Since natural gas is recognized as the environmentally preferred hydrocarbon fuel for end use, decreasing production due to upstream regulations is inconsistent with the desire to increase natural gas use.

Total Production Impact

Reference Case 1

Using the reserve impact modeling approach described in the introduction to this chapter, the production volumes for the lower-48 states are shown in Figure 6-7 for both the Reference Scenario and high regulatory compliance scenarios under Reference Case 1. Note that the difference between environmental regulation scenarios, or the net decrease in production due to higher compliance costs, is nearly 2 TCF per year by 2010 with a cumulative reduction from 1992-2010 of over 17 TCF. It should also be noted that production decrease increases throughout the period as existing production declines and new discoveries and infill development drilling play a larger role in the supply forecast.

Reference Case 2

Under this lower energy demand (Reference 2) case, the incremental decrease in production due to higher compliance costs is much greater than in Reference Case 1. Lower overall gas prices reduce supply in total, and higher environmental compliance costs cause fewer high quality wells to be drilled.

Figure 6-8 illustrates the production volumes for the two environmental regulation scenarios under Reference Case 2. The cumulative decrease in production due to the

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[9] American Petroleum Institute, *1990 Joint Association Survey on Drilling Costs*, 1991.

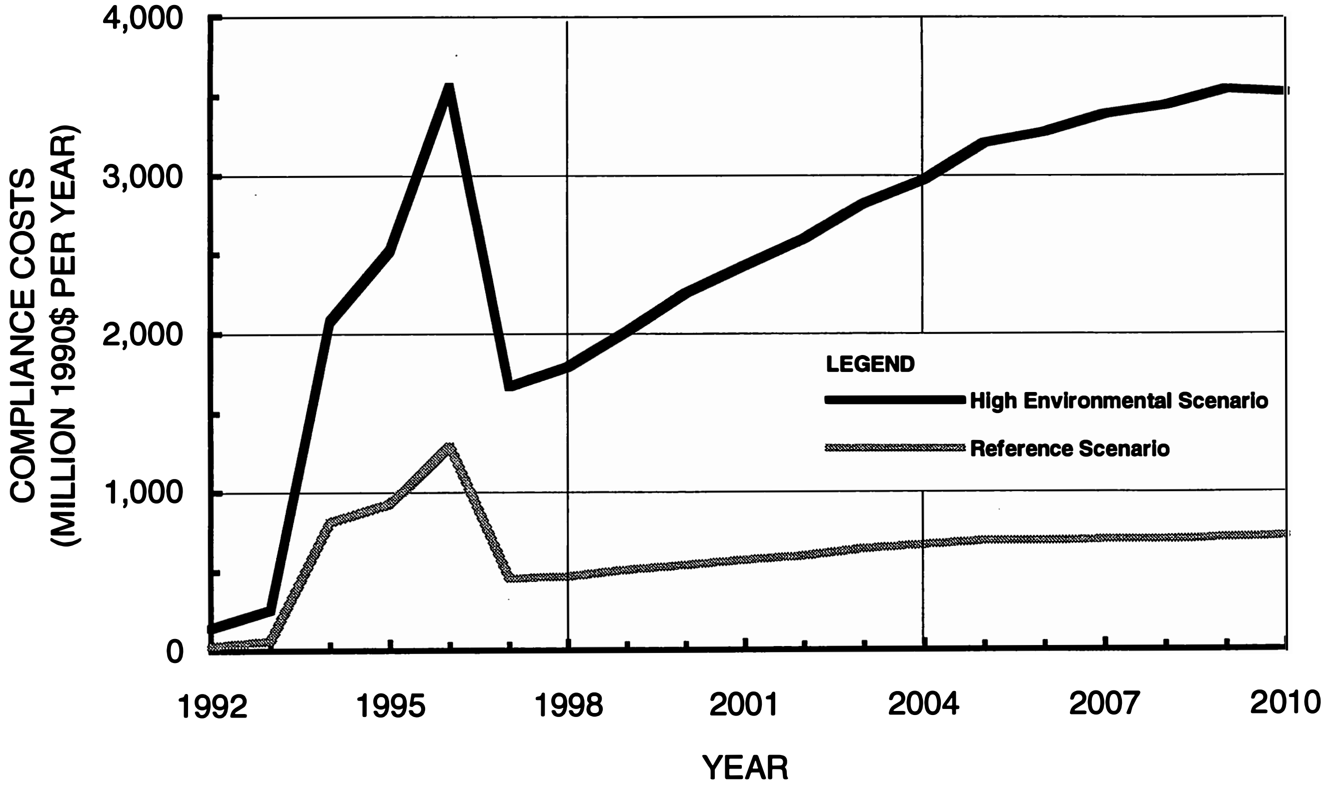


Figure 6-5. U.S. Lower-48 Natural Gas Exploration and Production Environmental Regulation Compliance Costs—NPC Reference Case 1.

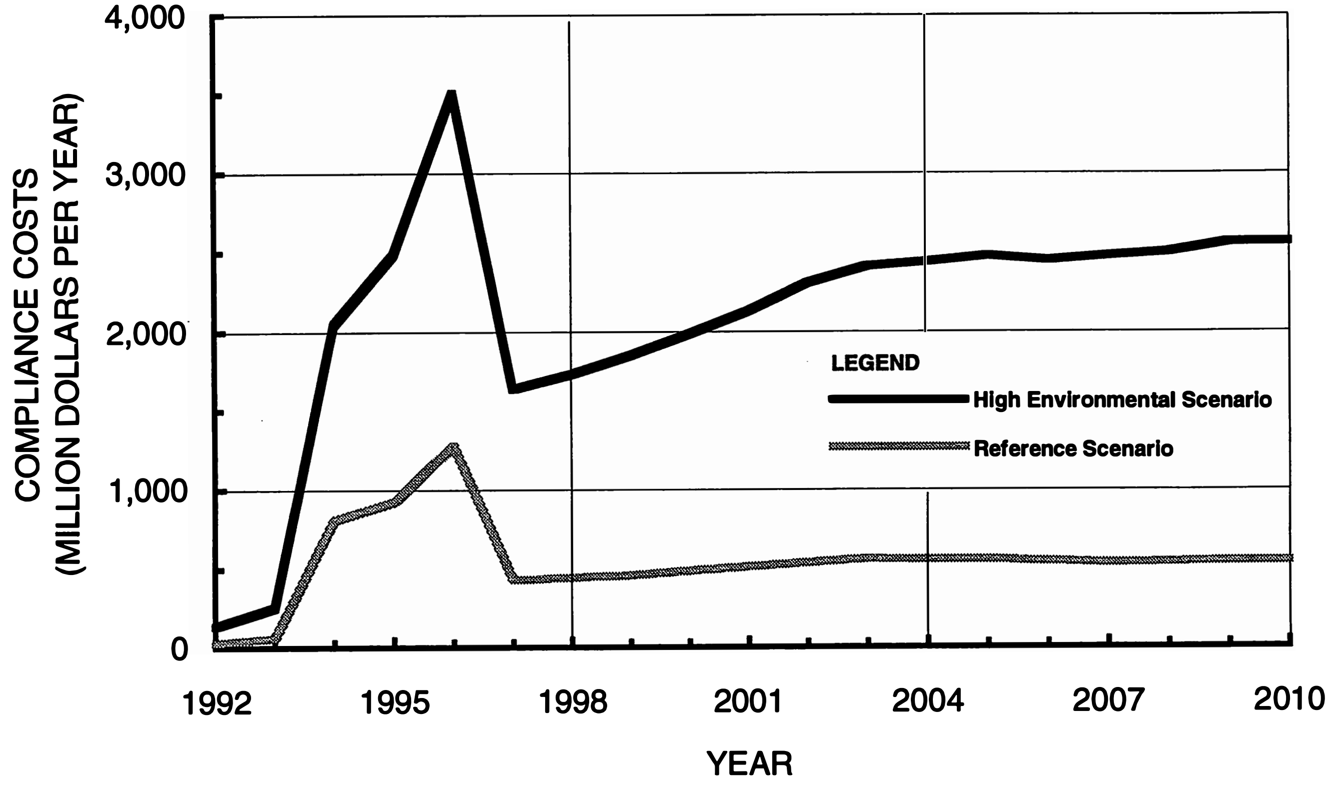


Figure 6-6. U.S. Lower-48 Natural Gas Exploration and Production Environmental Regulation Compliance Costs—NPC Reference Case 2.

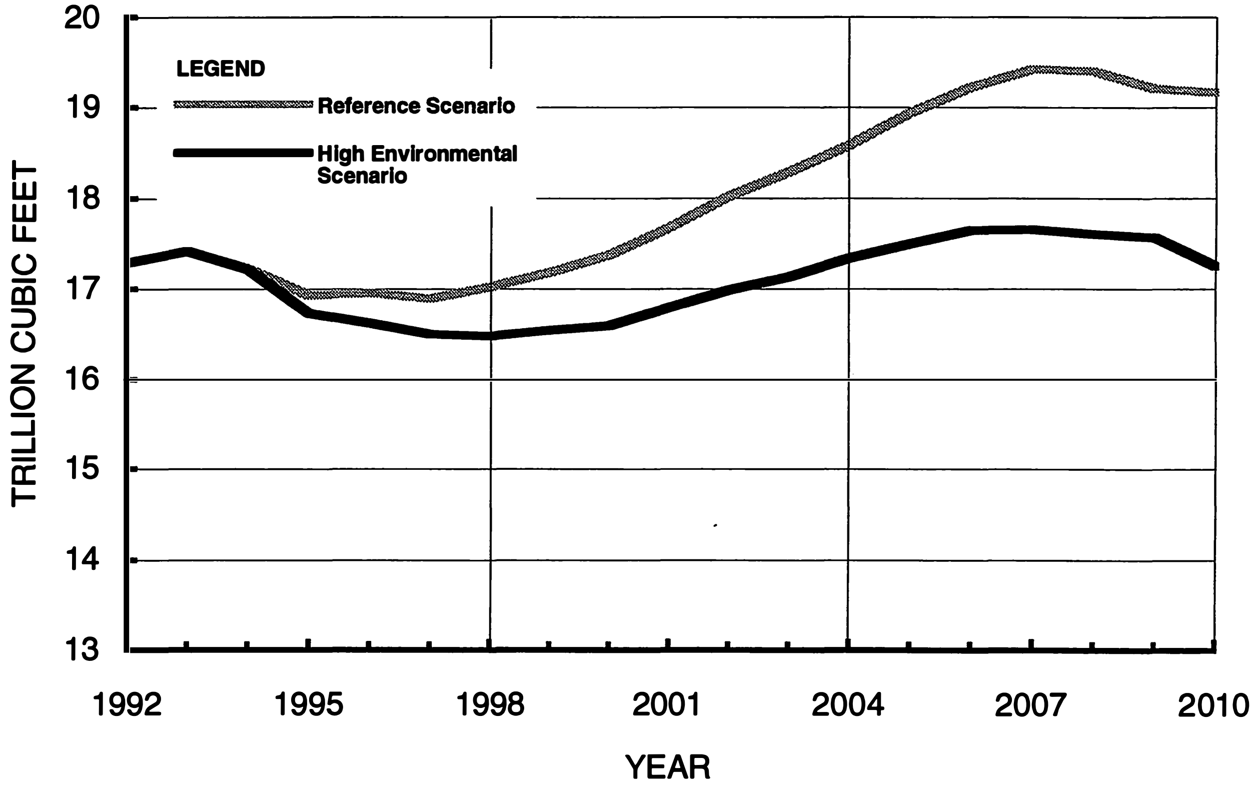


Figure 6-7. U.S. Lower-48 Natural Gas Production—NPC Reference Case 1.

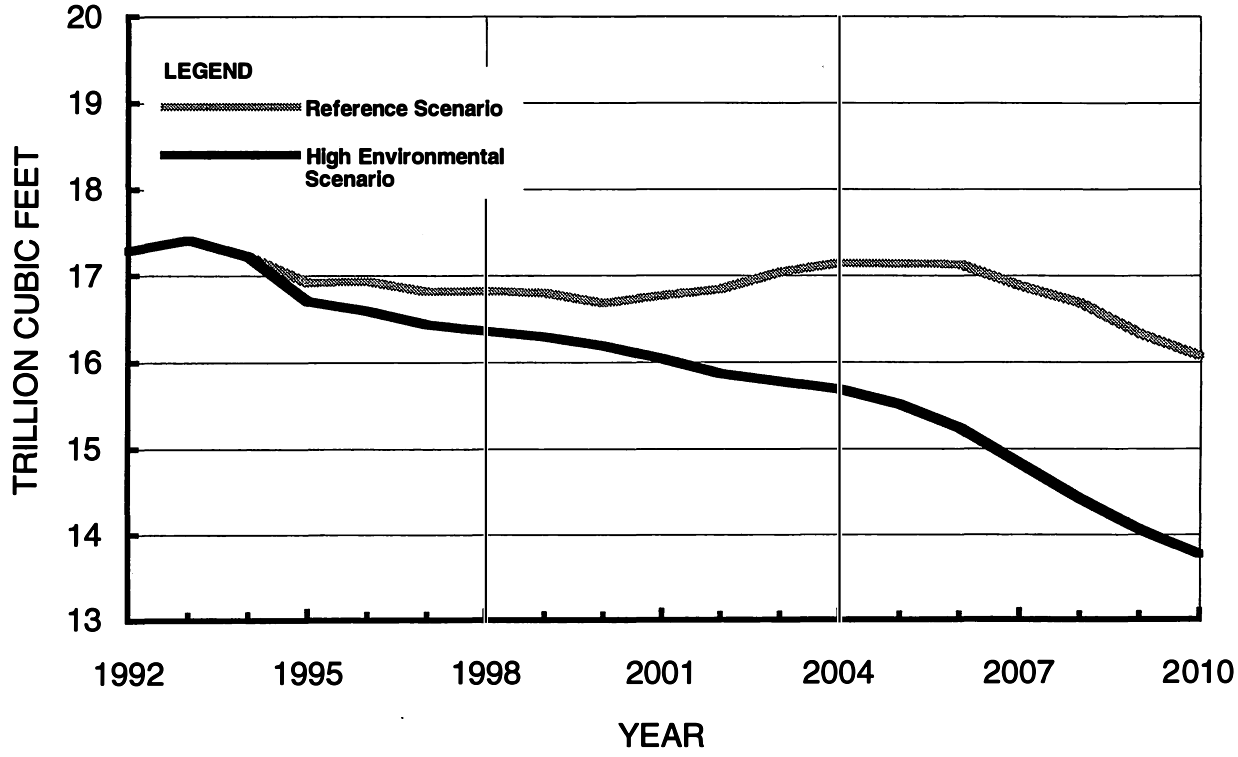


Figure 6-8. U.S. Lower-48 Natural Gas Production—NPC Reference Case 2.

high compliance costs, relative to the Reference Scenario, is over 19 TCF. Note also that there is a net decrease of 2.3 TCF per year by 2010, with the decrease continuing to grow through time.

Under either of the Reference Cases the reduction in natural gas production that occurs with the High Environmental Regulation Scenario is significant, reaching at least 10 percent by 2010.

Production Comparisons

To put a decrease in production volume of 2+ TCF per year in perspective, two comparisons have been made with other natural gas production and consumption volumes. These fairly simple comparisons were made in an attempt to characterize the magnitude of the reduction relative to other recognizable gas volumes. These comparisons also highlight the existing public policy conflict between upstream environmental policy that restricts production, and the growing downstream desire to develop and use more natural gas. Note that the reduced environmental production volumes use in each of the examples is the difference in total production volume between the two environmental regulation scenarios (see Figures 6-7 and 6-8).

Comparison to Tight Sands Gas Development Volumes

One segment of the resource base that has received considerable attention over the past several years is natural gas from tight sands. This resource has received Section 29 tax credits to help stimulate its development and thereby increase its contribution to the nation's energy supply. Comparing potential reduced production volumes of natural gas due to upstream environmental restrictions (from all sources not just tight sands) with production volume increases from new developments of tight sands provides a simple volume comparison with a widely recognized segment of the natural gas resource. At the same time the comparison provides an interesting contrast between the government's attempt to stimulate production through financial incentives on one hand, while restricting production due to the financial disincentives of increasing environmental regulations on the other hand.

Reference Case 1

Production from tight sands gas has been projected to reach over 2.7 TCF per year by 2010 and total nearly 33 TCF over the 1992-2010 time period (Figure 6-9). (See Chapter Three, Nonconventional Gas.)

As discussed earlier, the reduced production due to high compliance costs under this Reference Case could reach nearly 2 TCF per year by 2010, or 17.3 TCF cumulatively. For comparison, this equates to 53 percent of the cumulative tight sands production during this same period. In this case, the volume of gas reduced due to upstream environmental compliance requirements is equal to half of volume generated in an effort to stimulate the development of tight sands.

Reference Case 2

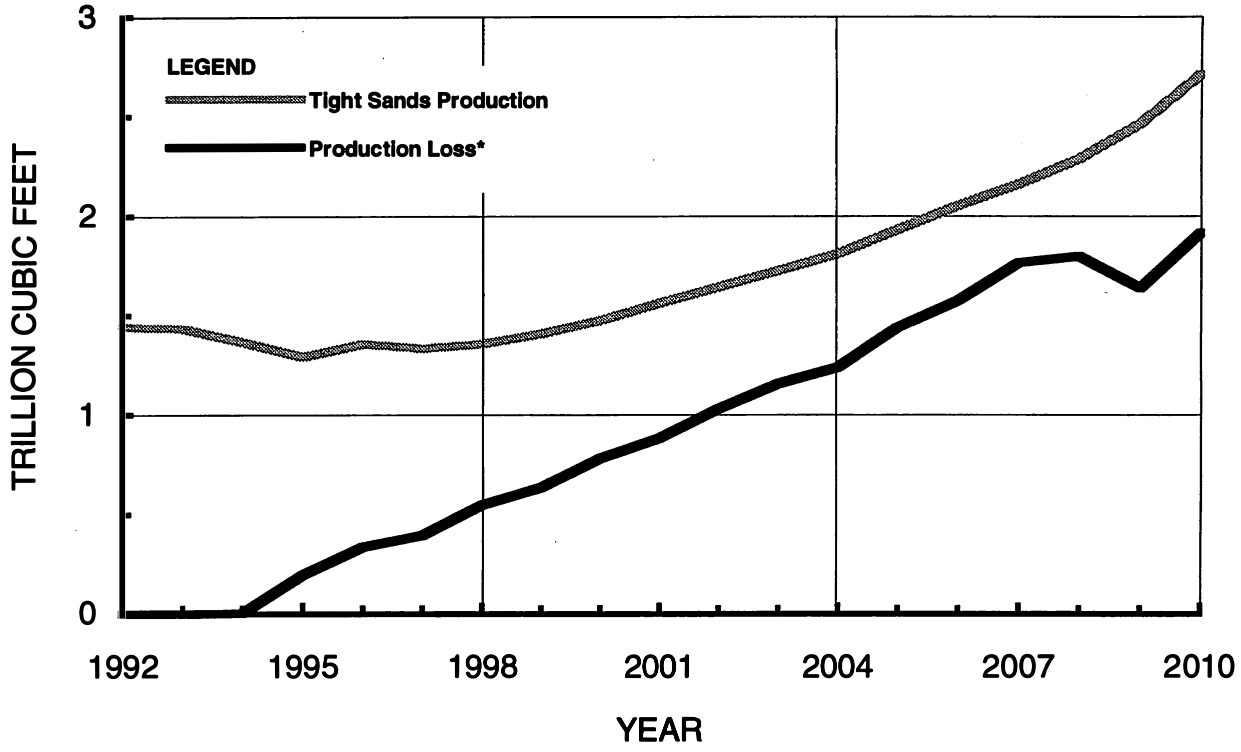
Comparing production from tight sands with total reduced production due to compliance costs under Reference Case 2 also illustrates the dramatic impact high environmental regulations can have in a slower economic growth environment.

Figure 6-10 shows that production from new tight sands grows to 2.2 TCF per year in 2010, and cumulatively accounts for about 30 TCF during the period. For comparison, total reduction in cumulative production volume from environmental restrictions under this Reference Case is 19.3 TCF (the equivalent of 64 percent of cumulative tight sands production), and the actual annual reduced production exceeds tight sands production beginning in 2006.

This comparison shows that the best of intentions to stimulate development and technology of a nonconventional resource to introduce more natural gas into the system can be in conflict with the environmental regulatory requirements on the upstream gas industry.

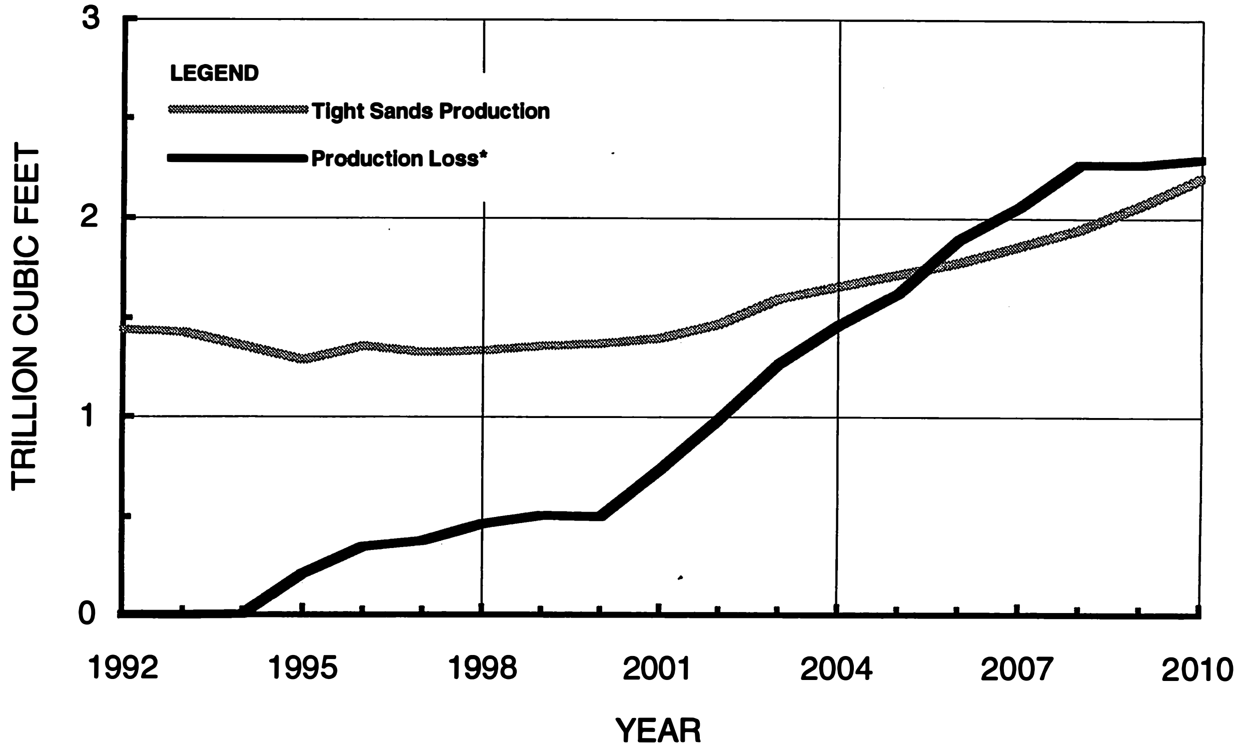
Comparison with Downstream Environmental Benefits

A significant amount of work has been done by both the public and private sectors to increase consumption of natural gas due to its inherent environmental qualities. The Demand and Distribution volume of this study has estimated, among others, the volume of gas that will be consumed by natural gas vehicles, gas



* Difference between production curves shown in Figure 6-7.

Figure 6-9. Reference Case Tight Sands Production vs. Loss of Production from High Environmental Regulation Scenario—NPC Reference Case 1.



* Difference between production curves shown in Figure 6-8.

Figure 6-10. Reference Case Tight Sands Production vs. Loss of Production from High Environmental Regulation Scenario—NPC Reference Case 2.

cofiring/reburning, and incremental combined-cycle units within the electric utility sector, all of which can offer significant environmental benefits.

A simple comparison of potential reduced production volumes of natural gas due to upstream environmental restrictions, with consumption increases driven by the environmental benefits of natural gas, provides another volume comparison, this time with a segment of the natural gas market. This comparison also highlights an even more direct example of competing government and/or public policy. On one hand, environmental policy on E&P operations is restricting production, while at the same time the Clean Air Act Amendments and other environmental issues are creating a growing environmental demand for increased consumption.

Reference Case 1

The total reduced production due to higher compliance costs compared to the total incremental gas demand that would have a significant environmental benefit [i.e., sum of natural gas vehicles, cofiring, and combined-cycle demand (exceeding today's level)] is shown in Figure 6-11. In Reference Case 1, the incremental natural gas volume driven by environmental demand exceeds 2 TCF per year by 2010, and the cumulative volume over the period is over 17 TCF. The potential reduced production in the E&P sector under this case reaches 1.9 TCF per year in 2010 with a cumulative volume that reaches approximately 17 TCF. Under this Reference Case, increased environmental demand is essentially the same size as the reduced gas volume in the E&P sector.

Reference Case 2

A review of the same analysis under a lower price and demand case (Reference Case 2) illustrates an even worse dichotomy. Under this case, the incremental demand with significant environmental benefit reaches 1.4 TCF per year by 2010, totaling 11.7 TCF over the period 1992-2010 (Figure 6-12). Reduced production due to high environmental costs under this case, however, exceeds 2 TCF per year by 2010, and cumulatively totals over 19 TCF (165 percent of demand with environmental benefit) over the period.

The observation from this analysis is that there is an inconsistency between the desire to burn more natural gas as a clean fuel, and the potential curtailing of the production of gas due to upstream environmental regulations. In addition, since demand and price were fixed in each of these model runs, the reduced gas production is assumed to be replaced by other, less environmentally acceptable fuels. If consumers wanted to buy more gas, they would have to pay a higher price to increase the supply. In other words, an opportunity to increase gas consumption could be lost, if environmental restrictions on E&P activities result in prices that will not allow natural gas to compete with less environmentally beneficial fuels.

Regional Production Impacts

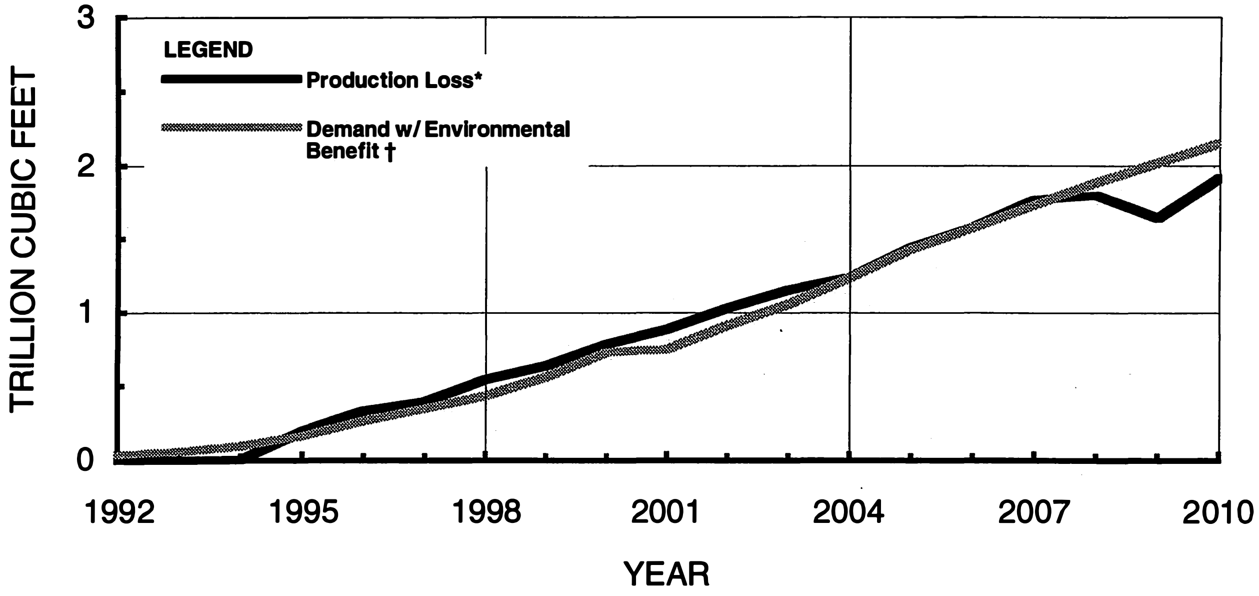
The production from some regions is affected more significantly than others due to inherent differences in regional resource distribution as well as the regional differences in compliance costs, as discussed earlier. In addition to the increased impacts on industry discussed below, this may have a significant impact on state and local governments that rely on royalty and tax income from the natural gas industry.

Reference Case 1

Several regions have a significantly reduced production in the High Environmental Regulation Scenario as compared to the Reference Scenario under Reference Case 1. Figure 6-13 illustrates the five regions that are impacted the most. For example Region C (North Central) production is reduced an incremental 1,371 BCF in the High Environmental Regulation Scenario over the Reference Scenario under Reference Case 1. This accounts for a reduction of nearly 25 percent for that region. Detailed regional production is provided in Table 12 of Appendix K.

Reference Case 2

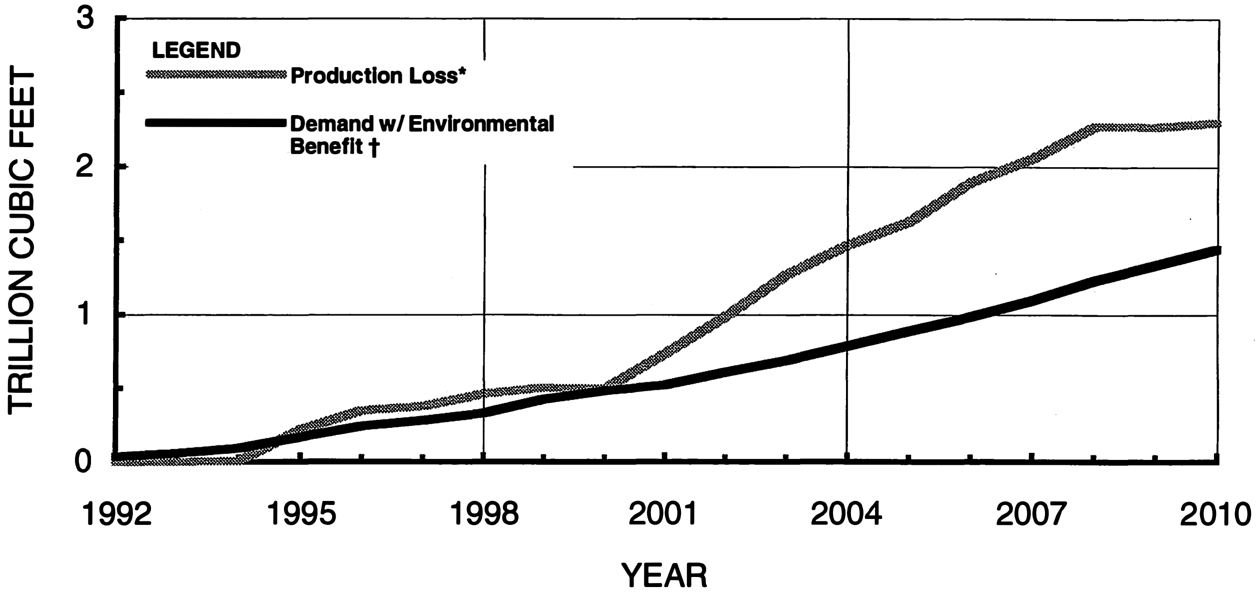
Under Reference Case 2, several regions also experience significant reductions in production (Figure 6-14). In this case, production in the North Central region is reduced an incremental 1.9 TCF or 40 percent of production in the Reference Scenario. Regional detail is in Table 13 of Appendix K.



* Difference between production curves shown in Figure 6-7.

† Demand form incremental natural gas vehicles, co-firing, and combined-cycle electric generating units in NPC Reference Case 1.

Figure 6-11. Reference Case Environmentally Beneficial Incremental Demand vs. Loss of Production from High Environmental Regulation Scenario— NPC Reference Case 1.



* Difference between production curves shown in Figure 6-8.

† Demand form incremental natural gas vehicles, co-firing, and combined-cycle electric generating units in NPC Reference Case 2.

Figure 6-12. Reference Case Environmentally Beneficial Incremental Demand vs. Loss of Production from High Environmental Regulation Scenario— NPC Reference Case 2.

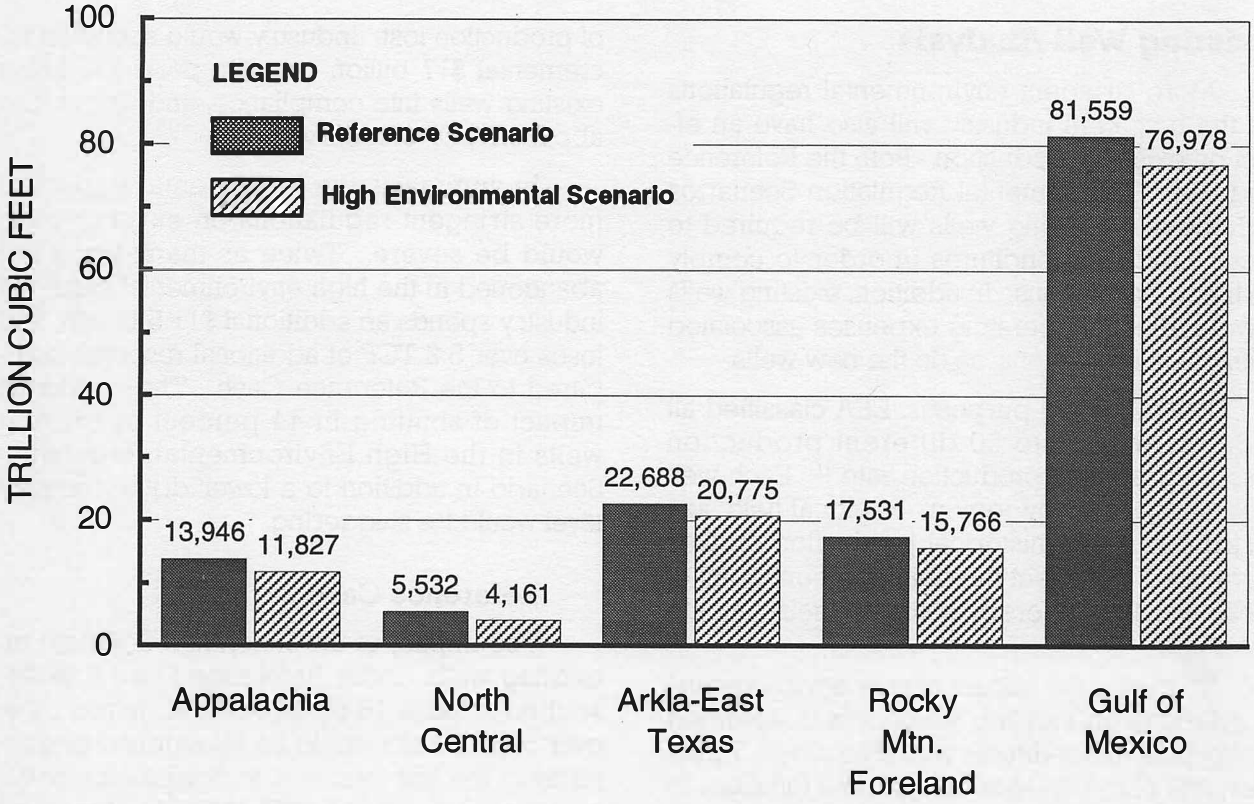


Figure 6-13. Cumulative Regional Production (1992-2010)—Reference Case 1.

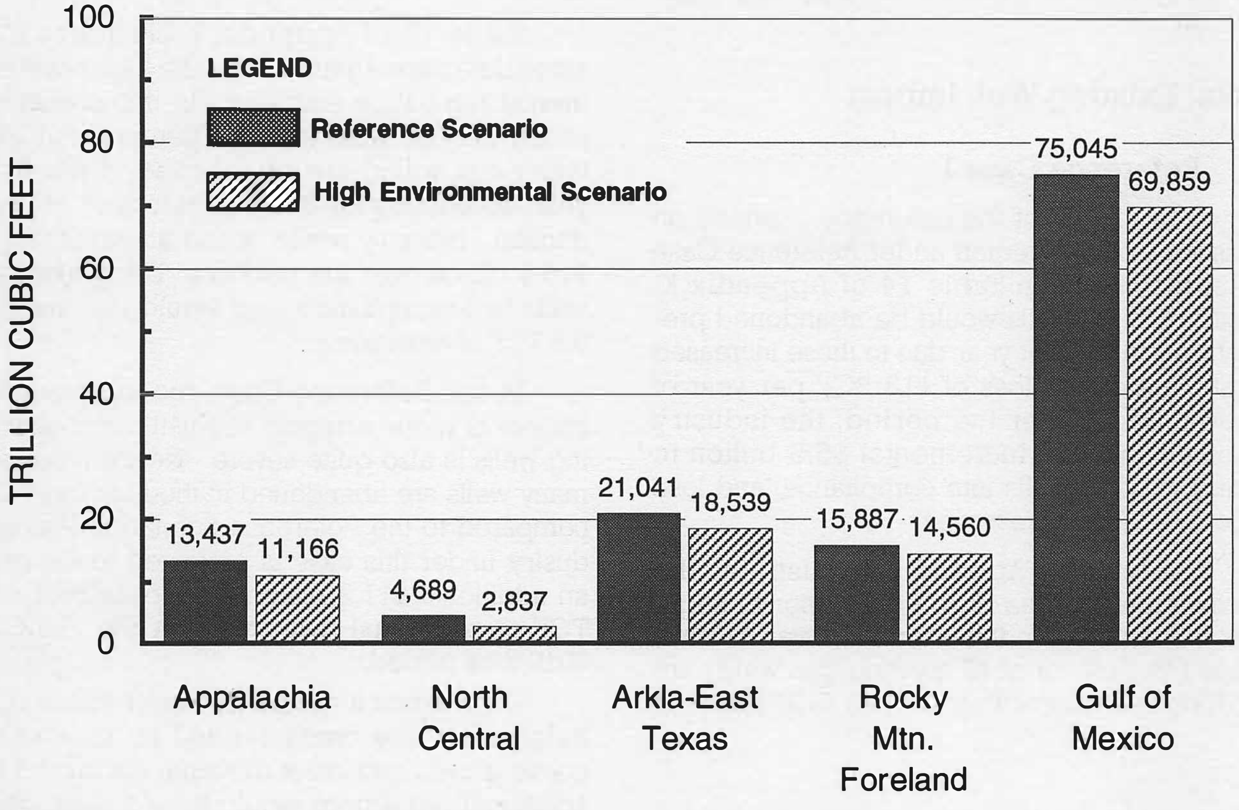


Figure 6-14. Cumulative Regional Production (1992-2010)—Reference Case 2.

Existing Well Analysis

More stringent environmental regulations on the upstream industry will also have an effect on existing production. Both the Reference and High Environmental Regulation Scenarios assume that existing wells will be required to incur capital expenditures in order to comply with new regulations. In addition, existing wells have additional operating expenses associated with these regulations, as do the new wells.

For modeling purposes, EEA classified all U.S. gas wells into 50 different production classes based on production rate.[10] Each well was categorized by region. Regional field size distributions and historical production profiles were used to project the abandonment point of these wells and thereby estimate their ultimate reserves.

To model the impact of new environmental regulations on existing wells, it was assumed that capital expenditures would require a 7 percent rate of return after tax (without inflation) to be considered economically viable. If the well could not provide this rate of return on compliance costs over the life of the well, then it was assumed that the producer would choose to abandon the well rather than upgrade the operation.

Total Existing Well Impact

Reference Case 1

The impact of the Reference Scenario on existing wells by region under Reference Case 1 is described in Table 14 of Appendix K. Nearly 57,000 wells would be abandoned prematurely in the first year due to these increased costs, creating a loss of 113 BCF per year of production. Over the period, the industry would spend an incremental $5.5 billion to bring existing wells into compliance, and lose about 877 BCF of reserves.

Table 15 in Appendix K illustrates the same impact for the High Environmental Regulation Scenario. In this scenario, over 113,000 wells (44 percent of all existing gas wells) are abandoned, accounting for 323 BCF per year of production lost. Industry would spend an incremental $17 billion over the period to bring existing wells into compliance, and would lose about 6.1 TCF of reserves.

In summary, the incremental impact of more stringent regulations on existing wells would be severe. Twice as many wells are abandoned in the high environmental case, the industry spends an additional $11.5 billion, and loses over 5.2 TCF of additional reserves compared to the Reference Case. The economic impact of shutting in 44 percent of existing wells in the High Environmental Regulation Scenario in addition to a lower drilling activity level would be staggering.

Reference Case 2

The impact of the Reference Scenario on existing wells under Reference Case 2 is described in Table 16 of Appendix K. In this case, over 57,200 wells would be abandoned prematurely in the first year due to compliance costs, creating a loss of 116 BCF per year of production. Over the 1992 to 2010 time period, the industry would spend an incremental $5.5 billion to bring existing wells into compliance, and lose nearly 1.0 TCF of reserves.

Table 17 of Appendix K illustrates the same data once again, but for the high environmental regulation scenario. In this scenario, nearly 116,000 wells (over 44 percent of all existing gas wells) are abandoned in the first year, accounting for 342 BCF per year of production. Industry would spend an incremental $16.6 billion over the period to bring existing wells into compliance, and would lose nearly 6.5 TCF of reserves.

In this Reference Case, the incremental impact of more stringent regulations on existing wells is also quite severe. Nearly twice as many wells are abandoned in the high case, as compared to the Reference Scenario. The industry under this case is projected to expend an additional $11.2 billion, and loses over 5.5 TCF of additional reserves over the 1992 to 2010 time period.

Once again it should be noted that in this Reference Case characterized by slow economic growth and lower demand, the impact of additional regulations would have a significant effect on existing wells and the economy in general.

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[10] See *Guide to the Hydrocarbon Model*, Energy and Environmental Analysis, Inc., 1992.

Regional Existing Well Impact

Note that the abandonment rate ranges from 44,585 wells in the first year in the Reference Scenario (Reference Case 1) to 86,824 wells in the High Environmental Regulation Scenario (Reference Case 2). Nearly 1.7 TCF of reserves could be lost from this region alone under Reference Case 2. Other regions that are impacted significantly include the Mid-Continent (JN), Arkla-Texas (D), Texas Gulf Onshore (G), San Juan Basin (SJB), and the Permian Basin (JS).

Observations and Conclusions

A summary of some of the key results from the modeling analysis is presented in Table 6-3. All of the values on the table are the incremental impacts, or deltas, between the Reference Scenario and High Environmental Regulation Scenario, illustrating the incremental impact of legislating or regulating more strict environmental compliance without balancing the cost and benefits of the upstream regulations, or taking into account the downstream benefits of using natural gas. The incremental data is presented for both Reference Cases.

The impact of high environmental regulatory compliance costs on the natural gas industry is significant. Not only will stringent requirements drain the producers of capital that could otherwise be used for reinvestment that could help the economy, but in fact, thousands of wells would not be drilled while others would be prematurely abandoned. Production would decline dramatically if prices did not rise to offset the producers' increasing costs. Ultimately some or all of these costs are passed on to the consumer. Local and state economies would also be impacted. Jobs would be lost, and severance and income tax, royalty, and lease bonus revenues would be reduced.

ISSUES NOT ADDRESSED IN THE MODEL

Overview

Numerous statutes, regulatory requirements, and policy decisions that may restrict access or add costs to domestic natural gas exploration and production were omitted or were only partially addressed in the model for various reasons, including:

- A lack of representative cost data or wide ranges in cost estimates.
- The lease-specific nature of permitting requirements, and evolving regulatory requirements.

TABLE 6-3

CUMULATIVE 1992-2010 IMPACT OF ENVIRONMENTAL REGULATIONS
REFERENCE VS. HIGH ENVIRONMENTAL REGULATION SCENARIO

Impact on Total Costs and Production

	Production Delta		Compliance Cost Delta	
	BCF	%	$M Total	$M Gas
Reference Case 1	17,331	5.1	85,800	35,703
Reference Case 2	19,276	6.0	70,534	29,527

Impact on Existing Wells

	Reserves Lost Delta	Compliance Cost Delta	Gas Wells Abandoned Delta	
	BCF	$ M Total	Wells	%
Reference Case 1	5,186	11.49	56,214	98.8
Reference Case 2	5,536	11.15	58,366	101.9

- The lack of adequate resource estimates on various public lands, especially unconventional resources. In some cases where published estimates are available, they are within the margin of uncertainty for the regional resource base estimates within the model.
- Wide variations in occurrence as with naturally occurring radioactive materials or endangered species.

The impact of these issues can be significant and would add to those impacts demonstrated in the model. A brief discussion of the issues not modeled is provided below.

Public Lands Access

The U.S. federal land inventory consists of some 720 million acres of property onshore; nearly one-third of the entire land area of the country. Approximately 41 percent of all federal lands onshore are currently unavailable to the natural gas industry. These lands include: (1) designated wilderness, and lands recommended and under study for wilderness; (2) National Park System lands; (3) Fish and Wildlife Service lands; and (4) other lands closed by administrative action. In addition, another 20 percent of onshore federal lands, legally open to the industry, are effectively closed as a result of *de facto* moratoria and lease restrictions that significantly curtail natural gas operations. The most recent study of the conventional natural gas resource potential on federal lands onshore has yielded estimates ranging from 25 to 132 TCF[11] with the majority of the potential resource located in Alaska. No adequate studies have been completed to assess nonconventional natural gas resources that may be present beneath onshore federal lands. Resource estimates on federal lands are speculative. The lack of access to certain federal lands makes it doubtful that the true productive potential of these lands will be determined in the foreseeable future. The continuing trend to remove additional lands and to impose increasingly stringent lease restrictions may have a significant, adverse impact on the role federal lands can play in any domestic natural gas strategy.

Wilderness Lands

The National Wilderness Preservation System contains over 90 million acres of designated wilderness at over 474 locations. An additional 134 million acres are currently recommended or are under study for wilderness protection, and are closed to exploration and production by congressional moratoria. Most wilderness areas are administered by four federal agencies, the Bureau of Land Management, the U.S. Forest Service, the National Park Service, and the Fish and Wildlife Service.

Wilderness areas were defined in the 1964 National Wilderness Preservation System Act as "an area where the earth and its community of life are untrammeled by man, where man himself is a visitor who does not remain. An area of wilderness has been further defined to mean an area of undeveloped federal land retaining its primeval character and influence, without permanent improvements or human habitation, which is protected and managed so as to preserve its natural conditions and which (1) generally appears to have been affected primarily by the forces of nature, with the imprint of man's work substantially unnoticeable; (2) has outstanding opportunities for solitude or primitive and unconfined type of recreation; (3) has at least five thousand acres of land or is of sufficient size as to make practicable its preservation and use in an unimpaired condition; and (4) may also contain ecological, geological, or other features of scientific, educational, scenic, or historical value."

Based on mean estimates of technically recoverable resources, 21.4 TCF of natural gas are believed to underlie wilderness areas.[12] These are risked estimates, incorporating both the resource potential that may be found and the probability of finding it. The majority of hydrocarbon resources under wilderness lands are expected to reside in Alaska (about 89 percent of the gas resource). Within Alaska, the bulk of the resources are estimated to be in fields in the northern portion of the

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[11] G. L. Dolton, R. G. Mast, and R. A. Crovelli, *Estimates of Undiscovered Conventional Resources of Oil and Gas for Federal Lands, and for Indian and Native Lands of the Continental United States*, U.S. Geological Survey Open-File Report 90-705, 1990.

[12] R. F. Mast, R. A. Crovelli, and K. J. Bird, *Estimates of Undiscovered Recoverable Conventional Oil and Gas Resources Beneath Onshore Wilderness Lands in the United States*, U. S. Geological Survey, October 1990.

state. Outside the "1002 area" (area specified in Section 1002 of the Alaska National Interests Land Conservation Act) of the Arctic National Wildlife Refuge along the coastal plain, these wilderness areas lie roughly east of the Prudhoe Bay area and north of the Brooks range. The potential of wilderness areas outside the 1002 area of the Refuge is estimated to be about 28 percent of the gas resource on wilderness areas in Alaska.[13] Little is known about the oil and gas potential of wilderness lands, particularly in other Alaska wilderness areas where little seismic data have been collected. Adequate studies have not been done to determine the natural gas potential of these proposed wilderness lands.

National Park System Lands

There are approximately 80 million acres of land in the National Park System. These lands are closed to mineral leasing by the Mineral Leasing Act of 1920. Approximately 37 million of the 80 million acres have also been declared as wilderness.

Fish and Wildlife Service Lands

The U.S. Fish and Wildlife Service (FWS) administers some 89 million acres of federal land. These lands include the Wildlife Refuge System, various coordination areas, and other miscellaneous lands. Approximately 19 million acres of FWS lands are designated as wilderness. In addition, approximately 61 million acres are currently recommended or are under study for wilderness designation. Much of the remaining FWS lands is subject to regulations that prohibit or significantly restrict exploration and production activity.

Other Federal Lands

Approximately 60 million acres of additional federal land have been closed to mineral leasing by various administrative actions. These include 45 million acres affected by the Alaska Native Claims Settlement Act, and 15 million acres affected by the Endangered Species Act, the Clean Air Act, and proposals to establish "buffer zones" around national parks. Again, these lands have been withdrawn without adequate consideration of their natural gas potential.

De Facto Moratoria

Approximately 20 percent of the federal land inventory, mostly Forest Service lands, are currently inaccessible to the natural gas industry as a result of *de facto* moratoria. These restrictions flow from a variety of routine administrative actions, including unwarranted delays in issuing permits, the assignment to single-use operations lands, and the imposition of stipulations severely limiting or prohibiting leaseholders from the surface occupancy of leased lands. *De facto* moratoria have been caused by recent court decisions on National Environmental Policy Act compliance requirements for oil and gas leasing, resulting in a Forest Service determination that few of its forest plans contain sufficient discussion of cumulative environmental effects. The delays caused by the development of this information have brought oil and gas leasing in these areas to a halt. Since 1985, the number of acres under lease on Forest Service lands has declined by 65 percent.

Outer Continental Shelf Leasing Restrictions

The OCS is subject to the jurisdiction and control of the United States by authority of the OCS Lands Act and the Submerged Lands Act. The OCS is made available for oil and gas E&P through a bonus bid leasing system. Leasing activity is planned and announced in a 5-year OCS leasing program schedule specifying the proposed size, timing, and location of each lease sale. Long before a lease sale is held, the oil and gas industry conducts geological and geophysical (G&G) surveys of the unleased OCS lands to determine which if any blocks of the OCS are to be bid upon. This "presale" process is expensive and time consuming for oil and gas companies, but it is an essential step in deciding where to invest exploration capital.

Since 1982, Congress has used the appropriations process to adjust the 5-year program

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[13] U.S. Fish and Wildlife Service, U. S. Geological Survey, and the Bureau of Land Management, *Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment*, Report and Recommendation to the Congress of the United States and Final Legislative Environmental Impact Statement, April 1987.

schedule through "moratoria" blocking the Department of the Interior from conducting lease sales in certain OCS planning areas. The first moratorium was placed on a Central and Northern California lease sale because of environmental concerns. In subsequent years, additional areas were affected by moratoria as the OCS program became more politicized. Congress has included moratoria in every DOI appropriation since 1982, adding moratoria for the Mid- and North Atlantic, Southern California, Eastern Gulf of Mexico, North Aleutian Basin (Alaska), and Washington/Oregon OCS planning areas.

For companies that planned to invest in an OCS lease sale but were blocked by moratoria, the prelease costs for G&G data and planning overhead are sunk costs. There is also a lost opportunity cost of not being able to lease, explore, and develop new oil and gas.

In 1984, Congress added a new moratorium on exploration drilling on existing leases in the Eastern Gulf of Mexico. Since then, such drilling moratoria have also been enacted in other planning areas. Companies holding and paying for existing leases under drilling moratoria cannot drill for a return on their investment or abandon the investment. In 1990, the President placed some of the more controversial OCS planning areas under an administrative moratorium. These areas are to be studied and reconsidered for leasing after the year 2000.

Besides the sunk costs and lost opportunity costs, the loss of access to OCS lands creates uncertainty about investing in the OCS. The reduction in available acreage for exploration reduces the pace of offshore drilling, which sends economic ripples through the OCS service industries. In turn, the slowdown in those industries affects their suppliers. Eventually, the effect of a moratorium is the loss of the equipment, expertise, and infrastructure to support E&P activities in an area. The loss of drilling capability has serious, long-term implications for domestic energy production, imports of oil and the balance of trade, and the energy options available to the nation. Moratoria even affect the revenues of the U.S. Treasury through lost bonus bids, rents, and royalties.

Other Issues Affecting Access or Costs

Coastal Zone Management Act and Related Issues

Beyond the federal leasing process, development of OCS resources can face substantial obstacles from state and local governments. Proposals to explore or develop OCS oil and gas resources must pass through a large number of environmental reviews by federal, state, and local agencies. The implications of such reviews may range from minor delays to those that threaten the financial benefits of proposed projects. In the extreme, they can result in cancellation of proposed development or the denial of proposed projects.

The Coastal Zone Management Act of 1972 and its later amendments created incentives for states to more carefully regulate development within their coastal zone. Section 307 of the Act contains federal consistency provisions that prohibit federal agencies from issuing a license or permit for any activity that affects any natural resources, land uses, or water uses in a state's coastal zone until the state has agreed that the activity is consistent with its approved coastal management program, or until the Secretary of Commerce has overridden a state's objection to the activity. The requirements imposed by coastal commissions under Section 307 have been tested in federal courts, and the powers granted to the states include the ability to negotiate the conditions or deny approval of OCS projects. As an example of a consistency denial, one company operating in offshore California could not set a platform that had been towed across the Pacific. The platform was towed in circles for several weeks at a cost of approximately $200,000 per day. Coastal Zone Management Act amendments passed by Congress in 1990 expanded the scope of activities subject to state review by affirming that OCS lease sales may be subject to consistency review. Under the statute, states may establish environmental requirements to which lessees must adhere.

Local governments can approve ordinances that in various ways affect offshore oil and gas development. Local initiatives have been passed in at least 24 communities in California and have provisions that range from advisory support of local government efforts to control oil and gas development to the prohibition of onshore facilities. Federal courts in California have upheld many of the provisions of local ordinances restricting OCS oil and gas development. In the future, state involvement in OCS issues, such as lease sales and permitting, will increase.

National Marine Sanctuary Program

The National Marine Sanctuary (NMS) program is authorized by Title III of the Marine Protection, Research and Sanctuaries Act of 1972 (MPRSA) and is administered by the Department of Commerce National Oceanic and Atmospheric Administration. As of early 1992, 10 NMSs have been designated, including Channel Islands (California), Cordell Bank (California), Fagatele Bay (America Samoa), Flower Garden Banks (Texas/Louisiana), Gray's Reef (Georgia), Gulf of Farallones (California), Key Largo (Florida), Looe Key (Florida), and U.S.S. Monitor (North Carolina). Most were designated prior to 1989. Currently, four proposed NMSs are in active designation process, including Monterey Bay (California), Norfolk Canyon (Virginia/North Carolina), Olympic Coast (Washington), and Stellwagen Bank (Massachusetts). According to the MPRSA, the purpose of an NMS is to enhance protection for, as well as wise and multiple use of, discrete areas of the ocean possessing nationally significant environmental resources. The intent of the legislation was not to set aside large areas of the ocean for eternal preservation as marine wilderness. NMSs designated prior to 1989 involved only small and well defined areas meeting the criteria and purpose embodied in the MPRSA.

Since 1989, however, the NMS designation process appears to have been politicized by environmental interest groups for the purpose of preempting OCS oil, gas, and minerals activities. Recent NMS proposals have been made for exceedingly large areas and blanket prohibitions on oil, gas, and minerals activities have become common. Such prohibitions appear contrary to the intent of the MPRSA and may constrain offshore gas development activities.

The Department of the Interior/Minerals Management Service has concluded that the 10 designated sanctuaries have a "negligible" adverse effect on the recovery of the nation's gas resources. This conclusion is based on the fact that these existing sanctuaries are either very small or are located in areas with limited gas resource potential. The four sanctuaries currently proposed for designation have an estimated gas resource potential of at least 3.8 TCF. Restrictions on transversing sanctuaries would further constrain the ability to recover gas resources in adjacent deep water areas.

Marine Mammal Protection Act

The Marine Mammal Protection Act of 1972 provides protection to all marine mammal species, whether endangered or otherwise. Though it predominantly affects offshore drilling and production operations, the Act can affect onshore activities in coastal areas where marine mammals are present onshore. The Act prohibits the intentional or unintentional "taking" of marine mammals as a result of activities. The "taking" need not be lethal to an individual animal, or detrimental to the species as a whole. The penalties include seizure of the offending vessel or rig and civil fines. The greatest impact to natural gas E&P may be the cost of monitoring or mitigation programs to reduce effects on marine mammals. The Marine Mammal Protection Act is administered by the U.S. Fish and Wildlife Service and the National Marine Fisheries Service for species under their jurisdictions under 50 CFR Parts 216 and 228, and 50 CFR Part 18, respectively.

Endangered Species Act

The Endangered Species Act of 1973 (ESA) was passed to protect species of plants and animals from extinction. The U.S. Fish and Wildlife Service and the National Marine Fisheries Service administer the ESA (50 CFR Part 17, 50 CFR Parts 217-227, respectively) and determine if species under their respective jurisdiction are diminished to the point that their existence is threatened or, in the more severe case, endangered. The Services list as threatened or endangered, and provide protection to, species, subspecies, populations, or stocks. They may also designate critical habitat for such species.

The ESA requires that all federally conducted, funded, or authorized activities must not jeopardize the continued existence of plants or animals listed as threatened or endangered.

The Services do not actually permit projects. Rather, if an action may affect a listed species, federal agencies must enter into consultation with the Services to determine if the proposed activities would jeopardize the continued existence of listed species or adversely affect their critical habitat.

The ESA may affect development of natural gas resources in several ways. For both onshore and offshore resources, leasing lands or permitting exploration may require consultation with the Services. The consultation process can take up to 135 days, with additional time up front to gather or develop information, initiate consultation, and possibly discuss mitigation after consultation. Thus a delay of more than six months is possible. Generally, because the consultation requirement is recognized, the time delay is built into the planning process for a project.

More significantly, a result of the ESA consultation process can be the loss of access to lands for exploration or development. The product of consultation is a biological opinion wherein the Services determine if a proposed action is likely to jeopardize the continued existence of a species or adversely affect critical habitat. If a "jeopardy" call is made, the biological opinion must indicate reasonable and prudent alternatives that would avoid jeopardizing the species. If the alternatives are infeasible, or there are no alternatives, the federal agency, with limited exception, may not allow the project to proceed. A recent and classic example in another industry is logging on national forest lands, which may be blocked if it is within the habitat of the endangered Northern Spotted Owl.

Even if a biological opinion does not conclude jeopardy or block access to lands, it may require or recommend costly mitigation measures that may become conditions of federal approval for the project. Mitigations can include avoiding impacts by changing locations or using different equipment or techniques. The biological opinion may also recommend monitoring programs, off-site environmental enhancement, and funding of species recovery efforts. The mitigation may be associated with access to the drilling site, protection at the site, and construction of pipelines and processing facilities. The ESA has added approximately $100,000 to $200,000 in incremental environmental costs to OCS platform removal when offshore fields are abandoned. These incremental costs result from elaborate survey and procedural requirements to protect endangered sea turtles during removal of platforms using explosives.

Both Services have a backlog of species to list, which means more animals and plants and more critical habitats will be designated. State agencies may adopt federal lists and many have their own species list. The growing public awareness of, and concern for, the survival of wildlife will likely continue into the next century. Only severe disruptions in energy supply might alter the public mood toward endangered species, and then such change may be short lived, lasting only as long as the energy crisis. The likely effects of the ESA are diminished access to public lands and increased costs of doing business.

Wetlands

Estimates of the nations wetland inventory range from 170 to 382 million acres with Alaska accounting for 130 to 300 million acres of the total.[14] The wide range in the number of acres in the wetland inventory is the result of often ambiguous definitions of wetlands from state-to-state.

Wetlands protection and management are dealt with under several pieces of federal legislation including: the 1990 Farm Bill, the Emergency Wetlands Resources Act of 1986, the Clean Water Act, and the 1899 Rivers and Harbors Act. In addition, many states have enacted laws that apply to wetland areas. Agencies involved in regulating wetland areas include: the U.S. Army Corps of Engineers, the Environmental Protection Agency, the Fish and Wildlife Service, the Agriculture Stabilization and Conservation Service, the Soil Conservation Service, and the National Marine Fisheries Service. Section 404 of the Clean Water Act is the major regulatory program that deals with the dredging and filling of wetlands. The Army

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[14] S. P. Shaw and C. G. Fredine, *Wetlands of the United States, Their Extent, and Their Value for Waterfowl and Other Wildlife*, U. S. Department of the Interior, Fish and Wildlife Service, Circular 39, Washington, D.C., 1956; W. J. Mitsch and J. G. Gosselink, *Wetlands*, New York, Van Nostrand Reinhold, 1986; and R. W. Tiner, *Wetlands of the United States: Current Status and Recent Trends*, Newton Corner, Massachusetts: U. S. Fish and Wildlife Service, 1984.

Corps of Engineers has the primary responsibility of issuing permits authorizing dredging and/or filling activities in U.S. waters under Section 404. The Fish and Wildlife Service and the National Marine Fisheries Service both may make recommendations to the Corps during the permit application process. The Environmental Protection Agency has enforcement responsibilities under Section 404, and may deny a permit already approved by the Corps of Engineers if they find that the disposal site for dredged or fill materials will have adverse effects on water, wildlife, or recreational areas. As with OCS moratoria, denied access in wetland areas results in lost opportunities to recover sunk costs in the form of lease fees and geological and geophysical surveys.

Pressures to prevent the loss of wetlands will increasingly limit drilling in prospective areas for natural gas exploration and development. Increasingly stringent permit requirements add delays and operational costs for such activities as waste disposal, site preparation, closed drilling fluid systems, or the need to do directional drilling. In addition, permits may require wetland mitigation. Wetland mitigation may involve site restoration, construction of new wetlands, or wetlands banking. Mitigation costs can range from $70 to $230,000 per acre.[15] The result of these additional costs will effectively prevent, or significantly delay, many areas from being explored and/or developed.

Naturally Occurring Radioactive Material

During the early 1980s, radioactivity was observed in North Sea oil and gas operations, and in 1986 naturally occurring radioactive material (NORM) was identified in tubing removed from a Mississippi well during a routine workover. Since that time, many operators in the United States have surveyed their operations and found NORM to be present at some locations, both onshore and offshore.

NORM is found throughout the natural environment and in man-made materials, such as building materials and fertilizer, as well as in association with some oil and gas production. NORM found in E&P operations originates in subsurface oil and gas formations and is typically transported to the surface in produced water. As the produced water approaches the surface and its temperature drops, precipitates form in tubing strings and surface equipment. The resulting scales and sludges may contain radium, along with other uranium and thorium daughter products. In addition, radon is sometimes contained in produced natural gas and can result in the formation of thin radioactive lead films on the inner surfaces of gas processing equipment. In oil and gas operations, the occurrence of NORM has typically been at widely scattered locations, in small quantities, and at low levels of radioactivity.[16]

At present, there are no federal and few state regulations directly applicable to the generation, storage, transport, or disposal of NORM in oil and gas operations. Louisiana has adopted regulations concerning worker protection and the transfer of properties containing NORM in oil field operations. Texas is also developing regulations.

Because of uncertainty regarding the occurrence of NORM and insufficient data on the costs for proper control, NORM was not addressed in the modeling effort. These potential levels of NORM management and disposal costs have been considered. If NORM with activities less than 2,000 picocuries per liter (low level radioactive waste) can be disposed onsite via downhole injection, landspreading, encasement in plugged and abandoned wells, or deep burial in mines or salt domes, costs are estimated to be on the order of $5/ft^3. If this low level waste must be transported and disposed off-site, such as at the Envirocare facility in Utah (the only approved facility in the United States for such wastes), costs are estimated to be on the order of $35 to $40/ft^3. Finally, NORM wastes that have activities greater than 2,000 picocuries per liter must be transported to and disposed at approved, centralized disposal facilities; costs on the order of $175/ft^3 are possible.

CERCLA/SARA

The Comprehensive Environmental Response, Compensation, and Liability Act

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[15] Anderson and Rockel, 1991.

[16] American Petroleum Institute, *Bulletin on Management of Naturally Occurring Radioactive Materials (NORM) in Oil and Gas Production*, Bulletin E2, First Edition, April 1, 1992.

(CERCLA) of 1980 gave the federal government broad authority and funding to respond to uncontrolled releases of hazardous substances to the air, water, and land. CERCLA was modified in 1986 by the Superfund Amendments and Reauthorization Act (SARA). In addition to changes to CERCLA, SARA created a free-standing law (Title III) governing reporting requirements for routine releases of toxic substances (referred to as community right-to-know provisions) and emergency planning for unanticipated releases. CERCLA is administered principally by EPA, the Coast Guard, and various state and local agencies.

SARA Title III Section 311 (40 CFR Part 370) requires the owner or operator of certain facilities, including gas E&P facilities, to notify the appropriate Local Emergency Planning Committee, the State Emergency Response Commission, and local fire department within 90 days of the presence at the facility of hazardous chemicals. At an exploratory well site or producing well site these may include sand, acid to treat underground formations, drilling mud, diesel fuel, and cement. Section 312 requires an annual inventory of all hazardous chemicals stored at or above 10,000 pounds. Requirements at the state and local level are still evolving, and in some cases are retroactive to cover operations in prior years. Estimates for complying with Sections 311 and 312 range from $25 to $76 million annually for the domestic oil and gas E&P industry.[17]

In the late 1980s, under CERCLA, the Department of the Interior promulgated procedures for making detailed assessments of natural resource damages involving oil or hazardous substances. Recovered damage costs are used to restore or acquire damaged resources. In response to various lawsuits, revisions to certain procedures were proposed in 1991. As directed by the Oil Pollution Act of 1990, the National Oceanic and Atmospheric Administration has been developing natural resource damage assessment rules that will replace DOI rules for discharges of oil into navigable waters. Assessing the effects of these rules is difficult as incremental costs will be partially determined by the number and size of accidental releases to the environment.

Oil Pollution Act

The Oil Pollution Act of 1990 addresses oil spill prevention, liability for spill cleanup, and damage assessments for oil producers and transporters. Gas liquids are also subject to the requirements of the Act. Although regulations have not been promulgated under the Oil Pollution Act, the E&P segment of the natural gas industry will be affected by the Act's financial responsibility and oil spill contingency plan requirements. Offshore operators will have to show evidence of liability coverage of $150 million and may be subject to virtually unlimited liability in the event of an oil spill. This may severely limit the number of companies that will be financially able to pursue offshore activity.

Toxic Substances Control Act

Under the Toxic Substances Control Act, EPA may require submission of information on the environmental toxicity of commercial chemicals, including recordkeeping, reporting, training, and hazard warning requirements. For several years, compliance has been frustrating because EPA lacks a clear and consistent process for communicating its reporting requirements under the Act. Interpretations of EPA policies vary as to how the Toxic Substances Control Act, Section 8(e) specifically, applies to gas industry operations.

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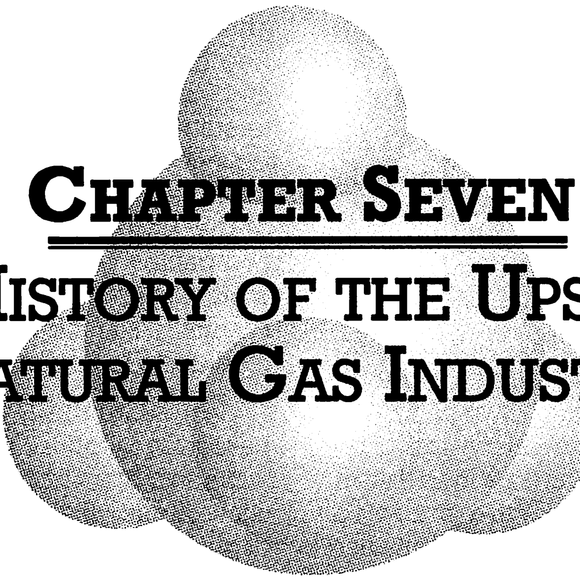
[17] Letter from Kenneth R. Dickerson, ARCO, to Richard D. Morgenstern, EPA, on President's 90-day regulatory review process, dated March 20, 1992; and Letter from G. H. Holliday, Holliday Environmental Services, to Richard D. Morgenstern, EPA, on President's 90-day regulatory review process, dated March 14, 1992.



CHAPTER SEVEN

THE HISTORY OF THE UPSTREAM NATURAL GAS INDUSTRY

The following material provides a historical perspective on the North American natural gas industry, highlighting the regulatory oversight that has accompanied the industry throughout its history and its impact on industry activity and performance. As the industry has developed and matured, the regulatory apparatus has been repeatedly modified in response to changing market conditions. The overall result has been to first open up a new source of energy by encouraging the construction of transportation and distribution facilities; then to encourage the public to accept natural gas by maintaining very low prices; subsequently, to encourage producers to develop reserves by loosening the reins on price; and finally, to open up access to the pipeline and distribution system to producers and consumers alike.

HISTORY

Although the exact beginnings of the natural gas industry are unknown, shallow deposits of natural gas exist around the world, which could have surfaced either on their own or with minimal effort by man. The first important commercial use of gas was for lighting, as an alternative to tallow candles and sperm whale oil, which became limited in supply. By the early 1800s it was known that gas could be obtained in a retort for coke, peat, or wood, and the idea of piping the product through iron or copper tubes to street lamps was considered. Demonstrations of gas lighting grew common in America in the early 1800s, and entrepreneurial enterprises sprung up in the form of gas light companies. By 1899 there were nearly 1,000 local distribution companies supplying a population of more than 24,000,000 in 885 towns.[1] During these early years, gas was nearly exclusively manufactured from soft or bituminous coal, or, where this was not available, from wood.

The gas industry was competitively challenged from the start. At first, the brightness of the gas flame and the lower cost provided strong incentives for conversion of existing whale oil lamps or tallow candles. However, the advent of kerosene created price competition, which spurred the technological development of the water gas process, patented in 1872. This process allowed manufactured gas to hold a significant market well into the 20th century. In addition, the industry developed demand-side stimulation, including the development of technology for gas cooking and heating.

Electricity posed a greater competitive challenge than oil after 1878, when Thomas Edison patented the first incandescent electric lamp. This development led to the rapid development of central power plants and overhead distribution lines and to direct competition between gas and electricity for lighting. Growing

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[1] E. C. Brown, Ed., *Brown's Directory of American Gas Companies*, 8th edition (New York: Progressive Age, 1899).

out of this competition, the gas industry sought other markets, including further development of gas stoves, home heating, and gas water heating.

Regulation of the industry began almost at the start when the early gas lighting companies were commonly granted exclusive franchises to operate in a market territory. The object of this initial regulation was to encourage the "modern convenience" of gas lighting by promising a guaranteed return on investment to those willing to lend the necessary capital to this risky new venture. When the safety and profitability of the town gas systems had been proved, however, attempts were made to deregulate the industry. This resulted in distributor competitions in which city streets were repeatedly torn up and replaced by competitive facilities and in "gas wars" between competitors affecting consumer prices. The problems of unrestrained competition between the utilities prompted re-regulation of the industry (and, in some cases, government ownership). During these early years, nearly all states adopted regulatory laws creating state utility commissions with regulatory power over the industry. This regulatory apparatus continues to this day.

With relatively stable demand, the average price of manufactured gas declined from 11¢ in 1922 to about 5¢ in 1940, and remained relatively constant in the 4.5¢ to 5.5¢ level during the next few years.[2] Consequently, from the earliest days of the industry through the period of World War II, the majority of the companies supplying the larger eastern cities found that manufactured gas continued to be more economical than natural gas for their volume requirements. Therefore, the natural gas industry was generally confined to the gas-producing regions of the United States, since there was no inexpensive means to transport gas over great distances.[3]

NATURAL GAS ACT OF 1938

By 1938, interstate movement of natural gas was becoming economical and the volume had reached more than 400 billion cubic feet annually. Interstate pipelines had remained free from federal regulation, although as early as 1935 there had been proposals to make interstate pipelines common carriers, and controversy over the common carriage status of pipelines continues to this day. With the advent of the Holding Company Act of 1935, some companies were forced to sell their pipelines, which then became private carriers who bought gas at the wellhead from producers and resold it to local distribution companies.

In 1938, the Natural Gas Act (NGA) was passed in response to a perceived need to protect consumers from monopolistic pricing practices of gas utilities and pipelines. At the time of passage, natural gas producers were exempt; the NGA regulated only the transportation and sale of gas in interstate commerce. Congress designated the Federal Power Commission (FPC) to enforce the NGA.

The surplus of gas produced as a byproduct of oil production kept the consumer's price of gas low during the 1940s and 1950s. In 1946, the average price for all natural gas was 17.8¢ per thousand cubic feet (MCF), and nearly 80 percent was used for industrial purposes[4] (carbon black production, chemical and allied products, iron and steel, stone, clay, and glass products, cement, food, and paper products), with consumption primarily located in the six principal gas producing states of Texas, Louisiana, California, Oklahoma, West Virginia, and Kansas. In the populous Middle Atlantic and New England states, natural gas was often not available, or at most was mixed with manufactured gas to upgrade the heating value of the manufactured gas.

A fundamental change in the scope of the industry occurred in the late 1940s, however. The cost for interstate transmission of gas decreased substantially, and with the advent of long-distance transmission capabilities, the industry boomed. An indication of the magnitude of this expansion is apparent from the annual sales of natural gas by interstate pipelines between 1945 and 1969. In 1945, the total was about 3 trillion cubic feet (TCF). By 1960, it had increased to over 12 TCF and by 1969, it had increased to almost 19 TCF.[5] This rapid

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[2] Federal Power Commission Annual Reports, U.S. Government Printing Office, Washington, D.C.

[3] *North American Natural Gas Markets*, EMF Report 9, Volume II, February 1989.

[4] FPC Docket No. G-580, Natural Gas Investigation, 1948.

[5] Federal Power Commission Annual Report, 1970.

rate of growth had been severely restricted during the war due to shortages of material and manpower. Petroleum exploration and development had continued, however, and the result was that more gas was available after the war than before, but the facilities for transporting it long distances to the northeast and midwest markets were limited. The war effort brought technological advancements directly applicable to long distance gas transmission. Among these were advances in the development of high tensile strength thin-wall steel pipe; advances in welding, pipe laying, and coating technologies; techniques for wrapping, blending, and backfilling; development of large capacity high speed compressor units for placement at spaced intervals; techniques for aerial surveying of right-of-ways; advanced water-crossing techniques; and dehydration processes.

During the 1950s and 1960s, the gas industry matured by supplying a vastly expanded post-war industrial base and millions of new homes constructed during the post-war period. The expanded use of energy was the prime means of achieving a much higher standard of living for the great majority of Americans. Also at this time, the chemical industry became a very large user of natural gas as a raw material, and natural gas began to be used as a raw material for making many fertilizers.

Between 1935 and 1950, the price of gas actually dropped 21 percent. Part of the drop was as a result of the technology advancements in gas transmission, which opened up more gas to the market at lower transmission and distribution costs. This increase in supply caused a decline in the unregulated wellhead price of natural gas. During the same period, the price of anthracite coal rose 94 percent, and the price of #2 fuel oil rose almost 97 percent.[6]

One of the principal regulatory controls on the industry during this period was the process of regulation through the issuance of certificates of public convenience and necessity. Such certificates were required prior to any construction or expansion of an interstate pipeline. To obtain a certificate, a showing of market demand and of gas supply was required. The latter typically involved the identification of a certain quantity of proved reserves, which were dedicated to the project for the life of the facility. Institutions providing investment capital relied on the dedicated reserves and the FPC findings and certificates as strong support for the viability of the proposed project over the life of the debt instruments. This process rapidly resulted in commitment of the formerly vast reserves of natural gas, and by 1950 readily available proved reserves were becoming limited. Thus, during the early 1950s, as gas demand exceeded supply in many parts of the country, severe competition began among many pipeline buyers for the existing proved reserves; and, predictably, the price for such reserves began to increase. However, the FPC continued to hold the line on producer prices, and in a few cases worked to roll prices back. The resulting effect was to discourage the exploration and production of gas.

THE PHILLIPS DECISION

The major federal regulatory control to this point was on the interstate pipelines, with state regulation of the local distributors of gas. However, in 1954 the Phillips Petroleum decision precipitated controls on producers. In the *Phillips Petroleum Company v. Wisconsin*,[7] the U.S. Supreme Court held that interstate sales taking place after the gathering or production function constituted a sale for resale requiring federal regulation. The 1954 Phillips decision plus the desire to keep the prices low for residential end users produced a long period of increasingly complicated regulation of wellhead gas prices and sharply increasing demand. As the regulations induced artificially low prices, they also encouraged the pipelines to expand through a system of cost pass-through "rate basing" that guaranteed the pipelines a profit and encouraged the construction of pipeline facilities. By 1968, this regulatory system had encouraged demand to such levels that consumption began to exceed reserve additions.

Until the late 1960s, the wellhead price for new gas sales into the unregulated intrastate market had tracked the regulated interstate price within a few cents. However, in the late 1960s, the low price of gas coupled with rising

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[6] U.S. Bureau of Labor Statistics, "Retail Price Indexes of Fuels and Electricity," January 1935-December 1957.

[7] *Phillips Petroleum Company v. Wisconsin*, 347 U. S. 672 (1954).

exploration and development costs caused a dramatic decline in additions to the proved reserve inventory. With demand for gas continuing to rise due to its low cost compared to alternative fuels, the unregulated intrastate market responded with rising prices. The interstate market was prevented from responding to these market forces, however, and the result was a dramatic decline in new reserve commitments to the interstate market. During the mid-1960s about 60-70 percent of reserve additions were committed to the interstate market and this had declined to around 10 percent by the early 1970s. By 1975 the average intrastate gas price was about 70 percent above the average in the interstate market.

There was another factor that aggravated the shift of reserve commitments away from the interstate market. Before a producer could sell gas into the interstate market, a certificate of Public Convenience and Necessity under Section 7 (C) of the NGA was required. One function of the certificate authorization was the setting of a "just and reasonable" price to the producer for his gas. Once a certificate was issued authorizing the sale by a producer, and the gas began to flow into interstate commerce, the gas became "committed" or "dedicated" to interstate commerce under the NGA. Such dedication to interstate commerce prohibited the producer from diverting the supply of natural gas from the interstate market without FPC approval. Cessation of the producer's duty to continue to deliver and sell the gas to the purchaser authorized under the certificate was commonly referred to as an "abandonment" of the service. If a producer desired to abandon a sale in the interstate market, the producer was required to seek approval of such abandonment even if the gas sales contract with the interstate purchaser had expired. As part of this producer regulation, the FPC required producers to file their gas sales contracts with the FPC as "rate schedules" under the NGA.

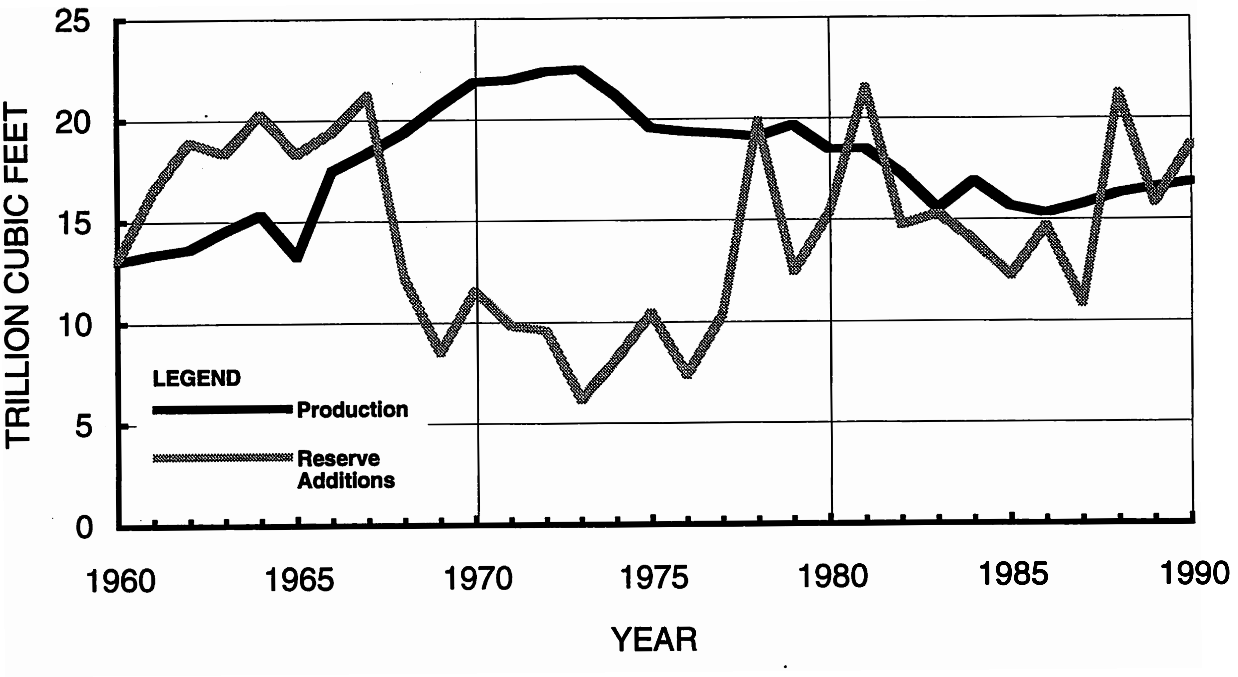
In the 1970s, the FPC established various generic procedures for setting natural gas producer prices. Initially these prices were determined in area rate proceedings in which individual producers' gas sales prices were tied to an average of the contract prices in a geographical area. The FPC's area rate proceedings then gave way to national rate proceedings.

Significant flaws were apparent in the producer pricing scheme established under the NGA and implemented by the FPC. Sales by producers to intrastate markets and sales by producers directly to end users in interstate commerce were not subject to federal price regulation under the NGA. Accordingly, industrial customers purchasing under direct sales contracts with producers and purchasers in the intrastate market were able to outbid the artificially restrained prices permitted for sales in the interstate market under the NGA. In addition, under the dedication restrictions of the NGA, a producer that sold its gas to a purchaser in the interstate market could not cease delivering and selling its gas to that interstate purchaser, even after its contract had expired, without first receiving abandonment approval from the FPC. Such abandonment approval was very rarely granted if there was a continuing need for such gas in the interstate market.

NATURAL GAS SHORTAGES

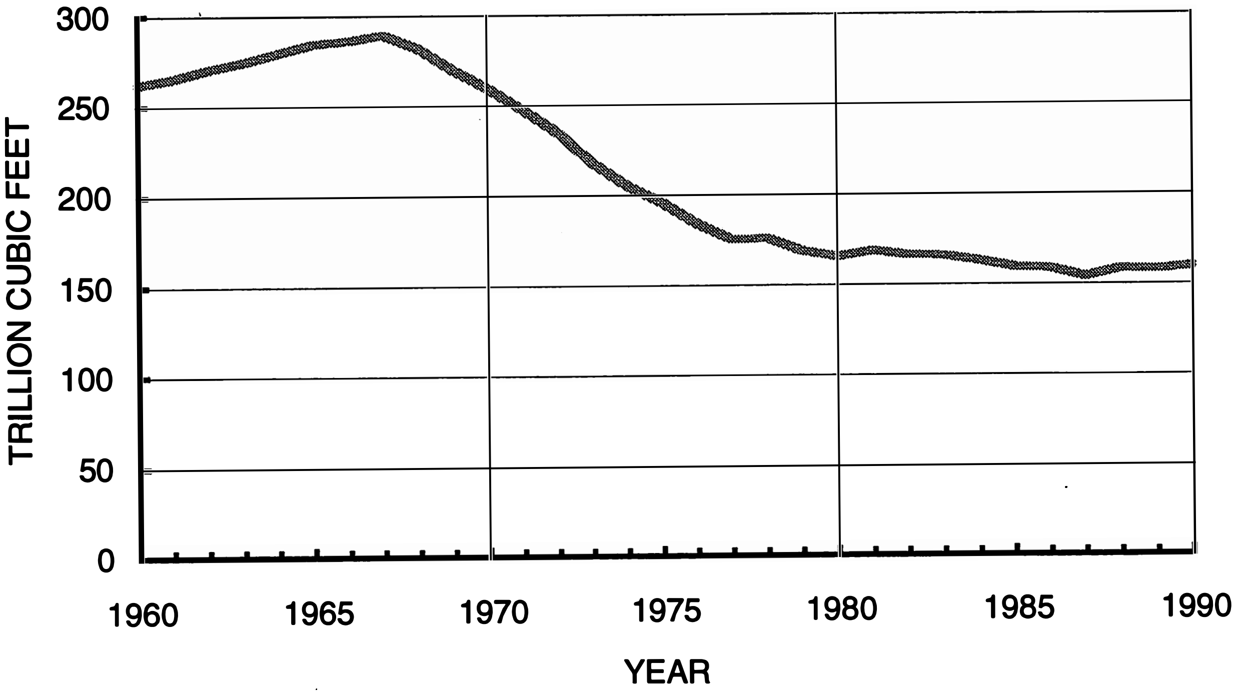
The effect of FPC regulation was a prolonged period of low gas prices and major gas demand growth. In the period from 1950 to 1970, gas demand grew from 3 TCF per year to 20 TCF per year and resulted in gas being transformed from a sometimes unwanted by-product to a valued commodity. At the same time, exploration for and development of natural gas became less economically attractive because of the low prices and rising costs.

The low gas price and rising supply costs failed to provide sufficient economic incentives to promote continued growth in the inventory of proved reserves. The turning point was reached in 1968 when production first exceeded reserve additions, as shown in Figure 7-1. Thus, the inventory of proved reserves in the United States began to decline as portrayed in Figure 7-2 as the industry began moving to a more economically efficient inventory level. The first signs of the shortfall began to become evident as some service interruptions began to appear. This was soon followed by regulators placing a moratorium on new gas connections. This declining reserve base resulted in total domestic gas production beginning to decline in late 1973. The following year, industrial customers of interstate gas supplies began to experience widespread curtailments of service. Although their contracts were interruptible,



SOURCE: 1960-1979: American Gas Association, Committee on Natural Gas Reserves, "Gas Facts."
1980-1990: U.S. Energy Information Administration, "U.S. Crude and Natural Gas and NGL Reserves."

Figure 7-1. Historical U.S. Lower-48 Production and Reserve Additions.



SOURCE: 1960-1979: American Gas Association, Committee on Natural Gas Reserves, "Gas Facts."
1980-1990: U.S. Energy Information Administration, "U.S. Crude and Natural Gas and NGL Reserves."

Figure 7-2. Historical U.S. Lower-48 Year-End Proved Reserves.

they had rarely experienced any loss of service. The shortfall of contracted supply obligations reached 16 percent nationally, while some regions were more heavily impacted. By 1976, production had declined by 12 percent from its 1973 peak.

When regulation of wellhead gas pricing first began, there was little difference between prices realized at the wellhead for gas sold into the interstate or intrastate markets. However, this began to change as the FPC imposed strict contract terms on interstate gas sales and declared that once gas was sold into the interstate market it was forever dedicated to interstate service. Free-market forces in the intrastate market allowed gas prices to rise as demand increased. Since the inflexible pricing policy pursued by the FPC in the interstate market did not permit prices to rise, new reserves were sold to the intrastate market. Ultimately, shortages began to appear in the interstate market forcing revised pricing procedures.

Concurrently, concern over the environment and its accompanying regulations along with low gas prices stimulated demand for gas among interstate customers, which worsened the shortages.

GAS CURTAILMENTS

In 1968, wellhead prices for new sales of gas to the intrastate market exceeded those for new interstate sales by nearly 20 percent, despite the average price of all interstate gas being higher than the intrastate price. This difference grew in the early 1970s, reaching a peak in 1975, at which time new contracts for intrastate sales received nearly two and one half times the price of gas sold in the interstate market.

Since rigid pricing policies in the interstate market did not allow supply and demand to balance, an alternate means had to be used to ration the short supply of gas. In 1970, interstate pipelines began to curtail the supply of gas to industrial customers. Regionally, there were big disparities since the supply situations of the different pipeline systems varied considerably. During the unusually severe winter of 1976-77, interstate gas supplies were curtailed to industrial customers and power generators in many Midwestern, Northeastern, and Mid-Atlantic states.

At the outset, "interruptible" customers, those industrial users whose contracts allowed service interruption during periods of peak demand, felt the brunt of the curtailments. These customers were largely electric utilities or large industrial users that maintained dual-fuel-burning capability in order to benefit from the "bargain rates" for interruptible service. The pipeline companies also benefited from the interruptible service since it provided them flexibility in managing the seasonal variation in loading. As gas shortages worsened, however, curtailments became the rule rather than the exception and extended beyond solely the interruptible customers. This forced the FPC to intervene in an attempt to develop a program for allocating available supplies.

After initially approaching the problem on a case-by-case basis, the FPC in 1973 issued Order 643, an eight-step curtailment plan that gave residential and small commercial customers the highest priority classifications for receiving uninterrupted supplies. However, Order 643 did little to overcome the underlying cause of the problem. For 1977, total curtailments reached 3.7 TCF.

SUPPLEMENTAL GAS SOURCES

When gas consumption began to exceed additions to domestic reserves, pipelines and suppliers were forced to look for alternate sources of gas to supplement supplies. Such sources included synthetic gas and coal gasification domestically, imports of gas from Canada and Mexico, and imports of liquefied natural gas (LNG) from overseas sources such as Algeria and Indonesia. Although these sources of gas were high cost relative to conventional domestic gas, pipelines were able to "roll in" the costs of the two sources resulting in an average supply price that enabled them to remain competitive. Price problems hampered the success of LNG projects. The original Border Gas Project from Mexico was scuttled because the price was too high relative to Canadian gas and other fuel costs, and the Alaskan Natural Gas Transportation System had not been built due to its huge capital requirement. Canadian gas remained a significant contributor, but the frequent export price adjustments caused serious consumer and policy concerns.

Of the synthetic gas projects, only the Great Plains Gasification Plant, which was supported by the U.S. government, was constructed and commenced operation. When the project was approved, it was expected that gas prices would increase substantially. When this did not occur, the operators sought price guarantees and debt restructuring. Failing to obtain approval for these measures, the operators terminated their participation in the project and the plant ownership reverted to the government. The plant has subsequently been sold to private interests.

THE NATURAL GAS POLICY ACT OF 1978

To remedy the problems resulting from the creation of a dual market (intrastate and interstate) for natural gas and to provide economic incentives for producers to drill for natural gas, Congress passed the Natural Gas Policy Act (NGPA) in 1978. The Act established pricing categories for all gas produced and sold in the United States. The price for gas that was committed or dedicated to interstate commerce prior to passage of the NGPA was set under a vintaging method determined in part by the year in which the gas was dedicated to interstate commerce or the year in which drilling of the well actually commenced. With passage of the NGPA and other National Energy Act statutes in 1978, Congress also created the Federal Energy Regulatory Commission (FERC) as successor to the FPC.

The NGPA established numerous natural gas categories, each of which was assigned a separate maximum lawful price. These categories depended on several factors such as the date the well was drilled and first produced natural gas, the date the field or acreage underlying a well was committed to interstate commerce, and the type of well or gas contract involved. In addition, certain special classifications of natural gas were established for each category of natural gas and a subsequent annual inflation adjustment factor was created for application to these base ceiling prices. Thus, under the NGPA, the base ceiling price was gradually increased each month. This statutory scheme worked so well that domestic drilling increased rapidly leading to the development of substantial new domestic gas reserves.

One of the major problems created by the NGPA scheme was the provision for automatic escalation of the maximum lawful prices for natural gas, with no provision for adjustments to reduce the ceiling prices, although parties to a contract were always free to negotiate a price below the ceiling price. Congress did not envision that the price of energy would ever decline, so there seemed to be no reason to provide for any adjustments to the maximum lawful prices other than an adjustment to escalate the base ceiling prices. Thus, although the cost of oil began to decline in the early 1980s, the price of natural gas continued to increase, and in fact actually exceeded the cost of fuel oil on a heating value equivalent basis.

The price of oil doubled in 1979 as a result of OPEC efforts, however, and it was widely believed that on January 1, 1985, when certain categories of natural gas would deregulate, there would be a dramatic "fly up" of natural gas prices to match the heating content cost of oil. Those projections did not take into consideration the dramatic decline in world oil prices and the general economic recession that occurred in the early 1980s, however. Thus, when prices for certain categories of gas were deregulated in January 1985, instead of a fly up there was actually a reduction in the prices.

Congress also provided additional transportation and sales authority for the FERC under Section 311 of the NGPA. At the time of the Act, interstate pipelines were experiencing severe shortages of gas while intrastate pipelines were full. To remedy the situation, Section 311 of the NGPA was designed to facilitate pipeline transportation by allowing interstate pipelines to transport natural gas on behalf of the intrastate pipeline or any local distribution company. The FERC expanded the transportation authority under Section 311 by providing a "self implementing basis," which means the transportation transaction could commence without prior approval of the FERC (subject to certain reporting requirements).

THE FUEL USE ACT

During the mid-1970s, a number of studies were published that claimed that the future of natural gas was limited. The primary factor cited was that the declining level of proved reserves indicated the exhaustion of the resource base. In hindsight, this view has proved to be unduly pessimistic and in actuality the producing industry was simply adjusting its inventory level (proved reserves) to a more economically efficient level. This perception contributed to various regulatory and legislative changes, however, which further distorted the market for natural gas.

The Power Plant and Industrial Fuel Use Act was enacted in 1978 as part of the National Energy Plan. This Act was developed in response to the shortages and curtailments of the mid-1970s and based upon the perception that the United States was running out of gas. It prohibited the use of oil and gas as primary fuel in newly built power generation plants or in new industrial boilers larger than 100 million BTU (British thermal units) per hour of heat input and also limited the use of natural gas in existing power plants based upon fuel used during 1974-76, and prohibited switching from oil to gas.

DECLINING DEMAND, THE GAS BUBBLE, AND DEREGULATION

Price-induced conservation, long-term fuel switching, industrial restructuring away from gas-consuming industries, and energy efficiency improvements reduced gas demand from around 20 TCF in 1980 to approximately 16.8 TCF in 1983. While deliverability had increased, gas consumption had declined, creating a "gas bubble" of excess deliverability. (As used here, "deliverability" means the capacity to deliver a certain quantity of gas on a sustained basis.) In response to the resulting industry problems, the FERC began a series of steps designed to deregulate the gas industry.

As a means of giving interstate pipeline customers greater flexibility in choosing between competing suppliers, the FERC issued Order 380 in 1984, which eliminated the requirement by pipelines that local distribution companies take-and-pay for a given amount of bundled merchant service but did still allow pipelines to bill for a given amount of transport costs. This spurred the development of the spot market in natural gas by permitting local distribution companies to turn away from their traditional pipeline supplier to new sources of lower priced gas supply. As a result, the spot market grew rapidly, from 5 percent of the market in 1983 to 33 percent in 1985.

Order 436 was another FERC initiative to restructure the natural gas industry through open-access transportation. By 1985, the "gas bubble" and the decline in spot market prices for natural gas were exerting severe economic pressure on the interstate pipeline system. System supply gas remained at high fixed contract prices while the prices of alternative fuels, i.e., fuel oil, declined with the breakup of OPEC price controls. In an attempt to deal with the differences in price available in the spot market relative to long-term purchase contracts, the FERC enacted Order 436 in 1985. The primary goal of the order was the establishment of a voluntary program by which interstate pipelines would make transportation capacity available to all seeking such service on a first come, first served basis.

The initial solution to the problem had been the authorization of special marketing programs, which allowed interstate pipelines to release high cost gas from contracts then resell it to industrial customers at market responsive prices. At the same time, pipelines normally sought relief from take-or-pay obligations for released gas. Special marketing programs, however, were limited in application and many residential and commercial gas customers were unable to participate. In *Maryland People's Council vs. FERC*,[8] the special marketing programs were ruled unduly discriminatory. Order 436 was the FERC response.

FERC Order 451 eliminated old gas "vintaging" pricing, which was based on the date of first production of the gas reserves. In place of the old vintaging system, Order 451 established a new ceiling price for all vintages of old gas, which a pipeline purchaser could purchase or release under a procedure called "good faith negotiations."

The Natural Gas Act had provided that any construction of facilities, extension of facilities, operation of facilities, sales for resale of gas in interstate commerce, or transportation of gas in interstate commerce required a "certificate of public convenience and necessity." Traditionally, such service was discontinued or

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[8] *Maryland Peoples Counsel v. FERC*, 761 F. 2d 780 (D.C. Circ. 1985).

"abandoned" only after a service was no longer required or facilities were no longer needed. This abandonment was a permanent event. In the mid-1980s, however, the FERC initiated a number of steps to expedite abandonment and/or to pre-grant abandonment of particular facilities or services. The FERC at first authorized limited term abandonments to allow producers to sell gas in interstate commerce for a limited period (typically two or three years). Later, under Order 490, the FERC established an expedited abandonment procedure for gas under expired or terminated contracts.

FERC Order 500 resulted from the legal challenge of Order 436. In *Associated Gas Distributors vs. FERC*,[9] the D.C. Circuit Court remanded Order 436 back to the FERC on grounds that the Commission had not adequately addressed the take-or-pay implications of open access transportation. In response, on August 7, 1987, the FERC issued Order 500. This order restated Order 436 with two major changes: elimination of the customer contract demand reduction option, and creation of a take-or-pay crediting mechanism. The take-or-pay crediting mechanism was designed to offset take-or-pay obligations of interstate pipelines caused by Order 436 transportation.

NATURAL GAS PRICES

Interstate wellhead natural gas prices have been regulated since 1954 and since sales to interstate pipelines dominated the market in the 1950s and 1960s, gas prices were relatively flat until 1970 as shown in Figure 7-3. Unfortunately, the result of the long period of stable and artificially low gas prices eventually was an unreliable supply of gas to the interstate market. This culminated in the mid-1970s in severe supply curtailments.

As a result of an initial unsuccessful attempt to regulate producer prices on a company-by-company basis, the FPC in 1960 moved to area-rate pricing based upon finding and production costs. The first area-rate case was the Permian Basin ceiling rate issued in 1965, with rates for other regions following. Area-rate pricing continued into the early 1970s, until the increasing trend of diminishing dedication of gas to the interstate market caused the FPC to move to a national-rate approach in 1974.

Gas exploration was being discouraged by the low gas prices; furthermore, the intrastate market, generally free from regulation, was able to attract new gas away from interstate markets through higher prices. Figure 7-3 shows how the difference between average intrastate and interstate prices began to grow in the mid-1970s. This growing price difference, along with the oil embargo of 1973, forced the FPC to raise interstate new gas prices from $0.40/MCF to as much as $1.42/MCF.

Despite these changes, interstate gas prices were still artificially low and there was no change in the trend of decreasing interstate dedications and total gas reserve additions. The declining supply of gas in interstate markets soon failed to meet all of the demand and the unusually cold winters of 1976 and 1977 aggravated the problem. This led to severe curtailments of interstate supplies from 1973 to 1979.

The complex system of price controls and incentives created by the Natural Gas Policy Act of 1978 attempted to let prices rise enough to spur new exploration while at the same time allowing consumers to benefit from low prices for old gas. However, this resulted in market confusion with a broad range of wellhead prices and a market price to consumers that varied between pipeline companies but was the same for all customers of any given pipeline. For example, gas from wells below 15,000 feet commonly sold in the $7 to $9/MCF range after deregulation in 1979. The concept of averaging this small but high-priced volume with large volumes of older, lower-priced gas resulted in small changes in the average price to consumers and allowed gas to remain competitive with alternative fuels.

The higher prices for new interstate gas spurred exploration and production as shown in Figure 7-4, which depicts the pattern of exploration drilling and gas well completions for the lower-48 states from 1960 to 1990. At the same time, gas demand declined in response to higher prices and economic recessions. The ultimate result was to shift the U.S. industrial structure away from gas-intensive industries

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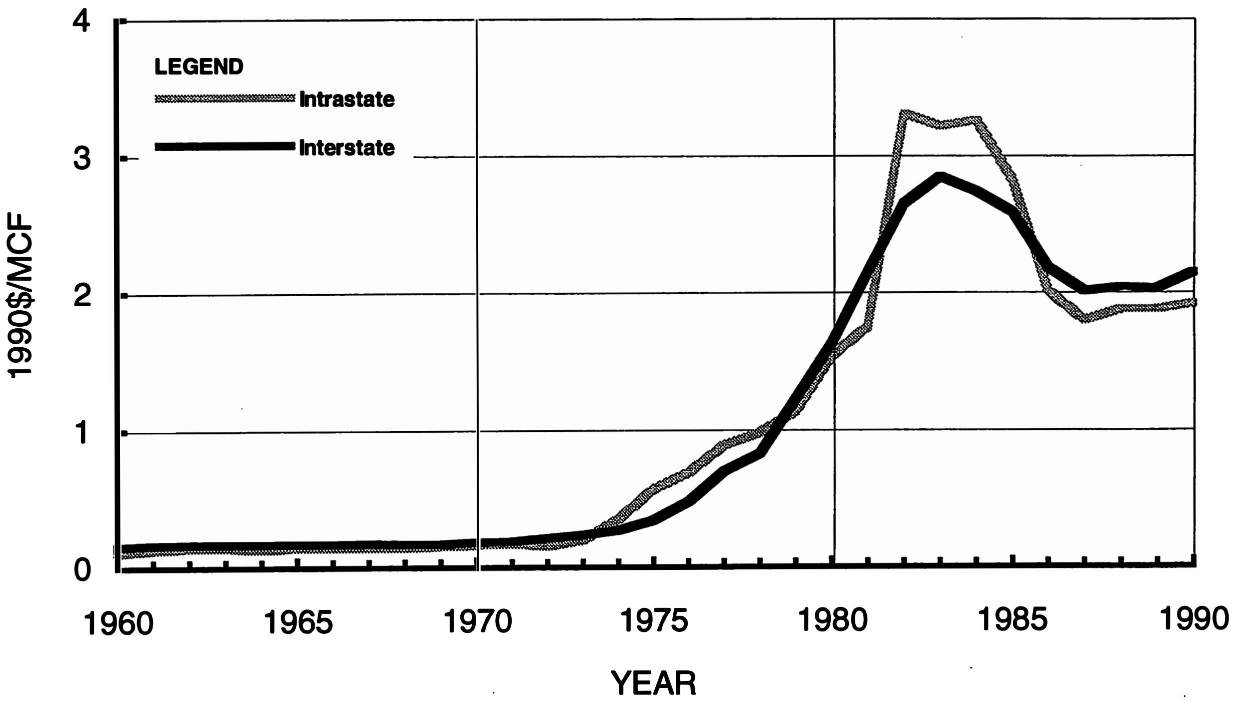
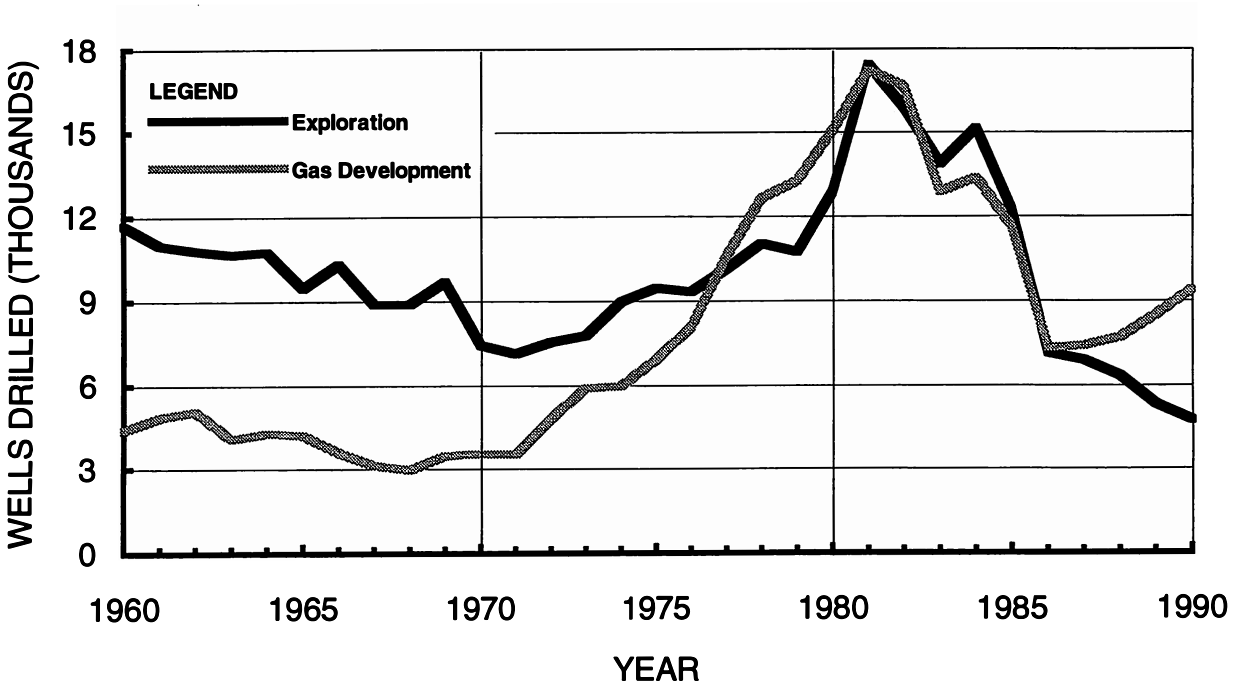
[9] *Associated Gas Distributors v. FERC*, 824 F. 2d 1081 (D.C. Circ. 1987).



SOURCE: 1970-1981: NPC report "Factors Affecting U.S. Oil & Gas Outlook."
1982-1990: Energy Information Administration publication "Natural Gas Annual."

Figure 7-3. Historical U.S. Annual Average Wellhead Gas Prices—Interstate and Intrastate Markets.



SOURCE: 1960-1965: American Association of Petroleum Geologists and "Oil & Gas Journal."
1966-1969: API, "Quarterly Review of Drilling Statistics."
1970-1981: API, "Well Completions and Footage Drilled in the United States, 1970-1982."
1982-1990: API, "Quarterly Completion Reports."

Figure 7-4. Historical U.S. Lower-48 Drilling Activity—Exploration and Gas Development Wells.

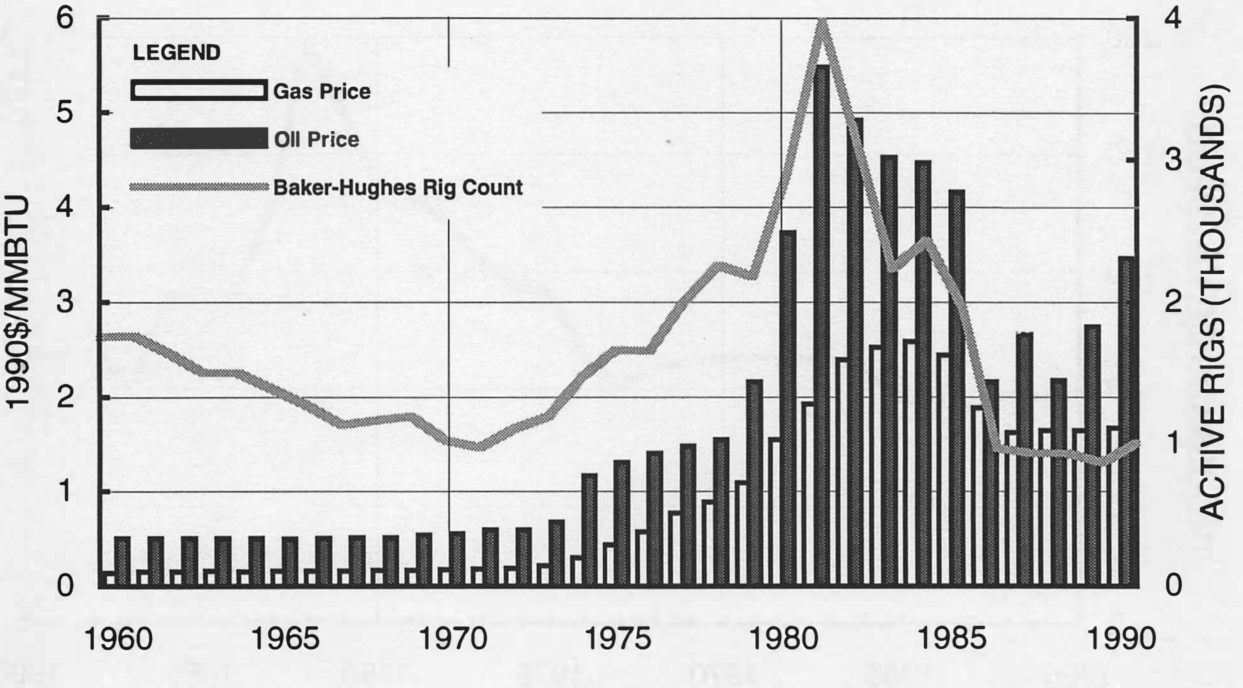
toward fuel switching. Increasing gas deliverability resulting from the higher exploration activity coupled with declining demand caused a decline in gas prices and expanded competition between gas and alternative fuels and, indeed, even between various gas supplies.

A key year for the gas industry was 1983, when the average interstate wellhead price peaked at almost $3/MCF. Since that time, the price has declined to about $2/MCF, as seen in Figure 7-3. Since gas competes with residual fuel oil at the industrial burnertip in industries with fuel switching capabilities, and residual fuel oil prices began declining after 1981, it was inevitable that the price of gas at the burnertip had to commence decline. This burnertip price decline translated back to the wellhead in the form of lower prices. Even though oil prices stabilized, gas-to-gas competition resulting from excess deliverability caused gas prices to continue declining. The year 1988 marked the beginning of a major restructuring of the U.S. natural gas industry, a transition that is still unfolding.

EFFECT OF PRICES ON ACTIVITY AND COSTS

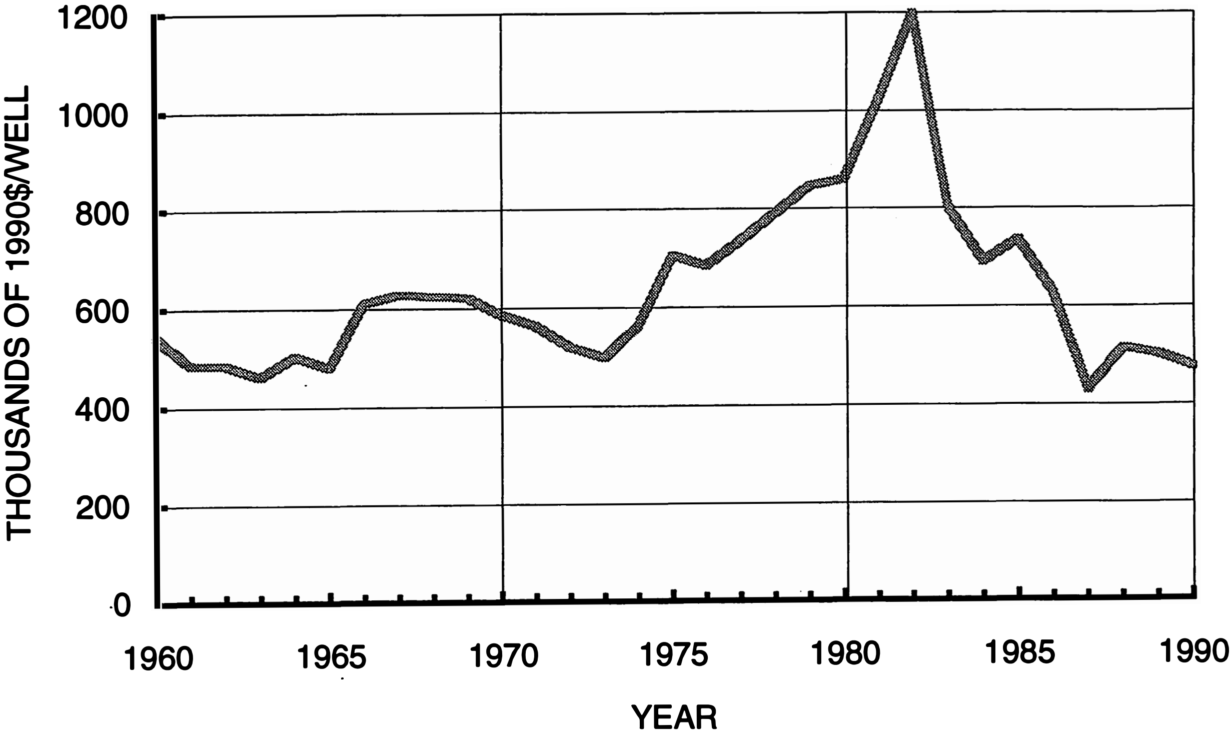
Exploration and development activity are driven primarily by current and expected oil and gas prices. Figure 7-5 compares the active drilling rig count to both the average wellhead oil price and the average Gulf Coast wellhead gas price in constant 1990 dollars. As shown, the rig count generally correlates well with price movements.

The rig count has varied considerably since the early 1970s, which has caused a wide swing in the demand for oil field services and supplies. The cost of these services and supplies as reflected in completed well costs have followed these activity swings. As seen in Figures 7-6 and 7-7, drilling costs doubled from the early 1970s to the early 1980s and subsequently declined to the former levels by 1990. This decline was primarily the result of an oversupply of drilling rigs caused by the response to demand for drilling in the early 1980s. This oversupply caused stiff competition among drilling companies for declining business, resulting in declining rig rates.



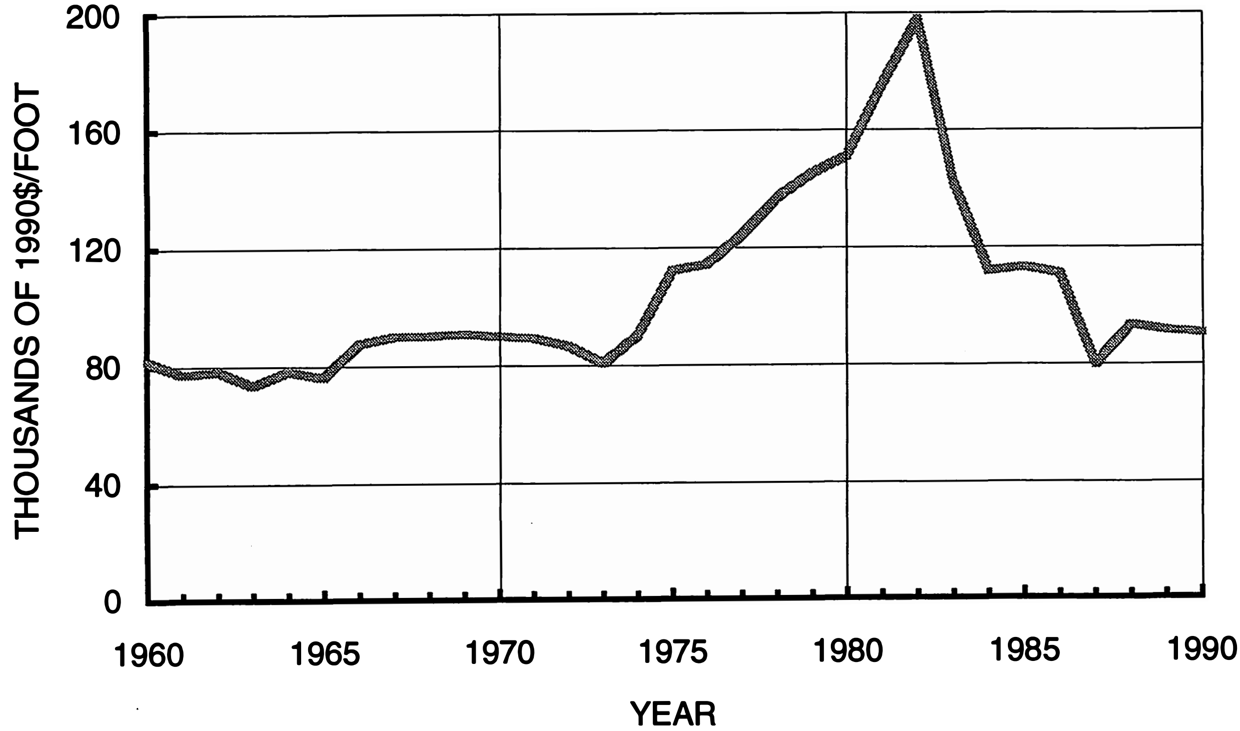
SOURCE: Prices from U.S. Energy Information Administration.
Rig count from Baker-Hughes Tool Company.

Figure 7-5. Oil and Gas Prices and Baker-Hughes Rig Count.



SOURCE: API, "Joint Association Survey on Drilling Costs, Annual."

Figure 7-6. Historical Gas Well Drilling Costs (1990$/Well).



SOURCE: API, "Joint Association Survey on Drilling Costs, Annual."

Figure 7-7. Historical Gas Well Drilling Costs (1990$/Foot).

THE EFFECT OF PRICES ON DRILLING AND RESERVES

Proved reserves of gas provide the inventory from which production of gas is drawn. The total remaining proved reserves decrease by the amount of production unless they are replaced through reserve additions.

Reserve additions will generally increase in response to more drilling activity, which in turn is driven by oil and gas prices as shown in Figure 7-5. Both oil and gas prices (1990$) have been markedly lower in the late 1980s as compared to the early 1980s. However, gas reserve additions have remained high, averaging 101 percent of production from 1986-90. With the low levels of drilling, such a phenomenon is not expected to continue and indeed preliminary estimates of 1991 reserve additions indicate only 70 percent replacement of production.

U.S. GAS SUPPLY

Total U.S. domestic gas supply peaked in 1972 at more than 22 TCF. However, the low regulated wellhead prices caused domestic gas supply to decline to about 20 TCF by 1975 (see Figure 7-1). Gas production stabilized at this level through 1981, as increasing prices promoted more exploration and development. However, due to the industrial factors cited earlier, gas consumption further declined to a level of about 15 TCF by 1986 before beginning a slow rise to the current level of about 17 TCF. Despite this reduction in consumption, total supply capacity remains in excess of 20 TCF per year.

LAGGED RESPONSE IN EXPLORATION AND PRODUCTION TO CHANGES IN PRICE

Oil and gas exploration and production is a long lead-time business. An offshore project can easily take up to 10 years to advance from preliminary geological and geophysical work to initial production. Frontier areas, such as deep water Gulf of Mexico, may require 10 or more years before production can be obtained.

Oil and gas production today still sees the effects from the high prices of the late 1970s and the first half of the 1980s, when these prices encouraged borrowing and generated revenues that could be plowed back into exploration and development. The drilling boom of the late 1970s and early 1980s was fed by expectations of ever-rising oil and gas prices.

Conversely, decisions not to invest because of today's low prices could have a lingering negative impact. Furthermore, when prices begin to rise, investors may react slowly, waiting until they can ascertain that the upward price trend is sustainable.

The oil and gas service sector has been hit especially hard. Some firms have been forced to combine with others out of economic necessity and many have approached or reached bankruptcy. Many skilled people have been lost from the industry due to the sustained nature of the decline. However, the service industry as well as the entire oil and gas industry proved its resilience and adaptability in the late 1970s when drilling activity nearly doubled from 1979 to 1981.

Financial institutions have historically supported the various components of the oil and gas industry but they were also hard hit by the rapid decline in oil and gas prices. Over the latter part of the 1980s, these institutions have faced higher levels of nonperforming and underperforming loans. This has caused a number of these institutions to fail or merge with stronger ones and resulted in an unwillingness, if not inability, to make available additional funding for oil and gas exploration.

OUTLOOK FOR THE INDUSTRY

The historical record to date shows that regulatory change has accompanied the industry throughout its history, as regulators, often after the fact, have restructured the regulatory apparatus in response to changing market conditions. The regulation of the industry has evolved stepwise, first opening up a new source of energy for the nation by encouraging pipeline construction; next encouraging the public to accept natural gas by maintaining very low prices; then encouraging producers to develop reserves by loosening the reins on price; and finally, opening access to the nation's pipeline and distribution system to both producers and consumers.

The movement to a less regulated industry has opened numerous opportunities for industry participants. However, taking advantage of these opportunities will require major changes in operating practices and the development of innovative means of securing the associated benefits. The increasing flexibility of the natural gas pipeline system engenders much greater competition in the marketplace and faster transmission of price signals. Services traditionally provided by the pipeline companies are now being provided by marketers and producers, and in some cases by the end users themselves. Transactions are becoming increasingly complex, and the transaction costs associated with the new opportunities are significant.

Additionally, regulatory bodies must still resolve certain outstanding issues affecting the industry. Impediments remain that restrict the functioning of the market in the era of open access. Comparability of service on pipeline systems and access to storage facilities must be addressed by the FERC. Producers generally have access to the pipeline system to negotiate deliveries directly with marketers and end users, but other types of access remain limited. For example, storage access could aid producers in maintaining relatively constant flows and deliveries into a market area. Greater access to secure firm transportation service could aid end users and producers in ensuring adequate supplies of natural gas even during seasonal periods when curtailments under interruptible contracts normally occur. Lastly, changes to federal regulation will require complementary modification at the state level.

LESSONS LEARNED FROM HISTORY

There are a number of lessons that can be learned from the history of the natural gas industry in the United States. Among the more significant are:

1. The effects of regulation may take a long time to become apparent but eventually market forces will prevail. For instance, it took nearly 20 years of controlling the price of gas at an artificially low level before demand rose to a level that exceeded the available supply.
2. The artificially low gas prices maintained by FPC regulation subsequent to the *Phillips* decision in 1954 spurred gas demand but failed to provide adequate incentives for companies to undertake the risk associated with oil and gas exploration and development. A free market will promote a healthy industry that is able to supply a commodity reliably and at a competitive cost.
3. Regulations should not be designed to "out-guess" the market but rather should let the market find its own price and quantity level. For example, the Natural Gas Policy Act of 1978 established a mechanism for the automatic escalation of maximum lawful prices but did not anticipate possible reductions in gas prices. This led to the assumption that upon deregulation on January 1, 1985, gas prices would rapidly increase and discouraged potential gas customers from committing to investments that would use natural gas. Government price-setting is likely to lead to unintended consequences contrary to the best interests of American consumers and their environment.
4. Regulations should not set arbitrary rules seeking to control gas demand but rather should let the price of gas and other energy sources govern demand. An example of regulation trying to control demand is the Fuel Use Act of 1978, which arbitrarily cut off the use of natural gas as the primary fuel in newly built power generation plants or new large industrial boilers. Where necessary, government should set standards but not specify the fuel and/or technology by which the standard is to be achieved.
5. Prices and contractual conditions mandated by regulatory bodies will result in market distortions. The FPC required that once dedicated, gas must remain in the interstate market. This, coupled with low regulated prices, eventually led to the market distortion of most new gas being dedicated to the unregulated intrastate market at significantly higher prices.

GENERAL REFERENCE

National Petroleum Council, *Factors Affecting the U.S. Oil & Gas Outlook*, February 1987.

CHAPTER EIGHT

IMPORT/EXPORT TRADE OPPORTUNITIES

SUMMARY

International natural gas trade, unfettered by excessive regulation and restrictions, can create substantial benefits for the U.S. gas industry and end users. These benefits accrue as a result of increased efficiency in the operation of the North American gas grid.

Increased productive capacity and additional possible routes from wellhead to burnertip create a more efficient industry serving U.S. gas customers. These expanded capabilities open additional markets to gas by creating an increased confidence among gas industry customers. The additional foreign sources of gas supply may in the long term provide important supplementary energy to the United States.

International natural gas trade serves to strengthen domestic production capabilities by establishing additional markets for gas sales. In effect, the broadened demand market extending into neighboring countries will contribute to the natural gas infrastructure of North America. As a result all these nations will realize the benefits of such trade.

INTRODUCTION

In virtually all natural gas supply scenarios in this study, natural gas imports are projected to play an increasingly important role in providing natural gas supplies to this country. During the early years of the forecast period, most of these additional supplies are projected to come from our historical supplier of imported gas, Canada; however, growth in imports from Mexico and other countries in the form of liquefied natural gas (LNG) are also expected in the latter years of the forecast period.

Although foreign gas supplies are expected to increase their market share in this country, natural gas export sales to Mexico, Japan, and Canada are also expected to grow in size, particularly if a more efficient North American gas grid is established over the next few years. Additionally, it is possible that substantial volumes of LNG could be exported from Alaska to the Pacific Rim countries in the latter years of the forecast period provided the proper trade and economic environments exist.

The United States and many of its trading partners have been making serious efforts to liberalize their trade policies and negotiate trade agreements that would foster free and fair trade. Nevertheless, there are a number of existing and potential regulatory and trade policy barriers that could inhibit the trade of natural gas between the United States and its international trading partners.

This chapter discusses briefly the history of policy and regulatory restraints on international natural gas trade with the United States; the relaxation of these trade restraints by this country and its trading partners over the past decade; the implementation of the U.S.-Canada Free-Trade Agreement and its effect on gas trade; legislation regarding the creation of a North American Free-Trade Agreement; and other recent initiatives to enhance trade.

This chapter focuses on the option of encouraging free trade of natural gas as an import and export commodity, the benefits and costs of taking such a position, and the recommended position of the natural gas industry toward this course of action.

HISTORY OF POLICY/REGULATORY RESTRAINTS ON INTERNATIONAL GAS TRADE

The United States has only been importing and exporting natural gas to any measurable degree since 1955. Over the past 37 years, the United States has traded with Mexico, Algeria, Japan, and Indonesia; however, Canada has historically provided over 90 percent of our country's international gas trade volumes. Although the United States has historically exported natural gas to Japan, Mexico, and Canada, the United States has been a net importer of gas since 1958. Natural gas imports as a percentage of total gas consumption in the country have grown slowly over the past three decades and reached a historic high of over 8 percent in 1991.

The 37 years of international gas trade has endured through an entire regulatory cycle like the rest of the gas industry—from limited government intervention to pervasive government intervention, and back again to efforts of limiting government intervention to only those areas needed to resolve market imperfections, in an effort to rely on market forces where possible.

From the mid-1970s to the early 1980s, international gas trade was characterized by heavy-handed government intervention, inflexible gas contracts, government imposed prices, and shortages of supplies. Today, natural gas import and export arrangements are more freely negotiated between the commercial parties, with minimal government involvement.

EVOLUTION TO A FREER U.S.–CANADIAN NATURAL GAS TRADE

The United States and Canada have taken a number of steps over the past eight years that have led to a more deregulated international market for natural gas. In 1984, the U.S. Secretary of Energy issued policy guidelines for natural gas imports. The guidelines were designed to encourage a more competitive atmosphere, allowing private parties freedom to negotiate import arrangements. The guidelines reflect the policy that the U.S. governmental role should be reduced to a level necessary to ensure that the private sector is operating in a competitive, market-responsive manner, and that the companies have freely negotiated contracts.

During 1984 and 1985, the Canadian government adopted a more market-oriented natural gas export policy, resulting in a steady shift away from government-set, uniform border pricing to fully negotiated agreements. By 1986, policy changes undertaken by the two countries resulted in significantly freer, market-oriented gas trade between the two countries. Today, Canadian regulation of natural gas exports is based solely on a "complaints" procedure, allowing commercial parties to negotiate the terms of their own export arrangements, including price.

U.S.–CANADA FREE-TRADE AGREEMENT

On October 3, 1987, President Reagan notified the Congress of his intent to enter into a Free-Trade Agreement (FTA) with Canada. On January 2, 1988, the FTA was formally signed by President Reagan and Prime Minister Mulroney. On January 2, 1989, implementation of the FTA began.

The general objectives and scope of the FTA are to: (1) eliminate barriers to trade in goods and services; (2) abolish impediments to cross-border investment; (3) establish predictable rules, secure access, and fair competition; (4) establish effective procedures and institutions for the joint administration of the FTA and the resolution of disputes; and (5) lay the foundation for further bilateral and multilateral cooperation to expand and enhance the benefits of the FTA.

In general, the main energy provisions of the FTA try to assure the freest possible bilateral trade in energy, including nondiscriminatory access for U.S. consumers to Canadian energy supplies and secure market access for Canadian energy exports to the United States. Specifically, the FTA prohibits restrictions on imports or exports, including quantitative restrictions, taxes, minimum import or export price requirements, or any other equivalent measure, subject to two limited exceptions. These two exceptions are (1) short supply or exhaustion of a finite energy resource and (2) national security, to supply military establishment supplies during an armed conflict.

The two countries recognize that the creation of an FTA will not eliminate all trade disputes between the two parties. Thus, the FTA includes measures for addressing future trade disputes. It provides for formal consultations to resolve any energy conflict resulting from a regulatory action taken by either country; and if the problem resolution process is not effective, the matter is referred to a five-member arbitration panel. Whenever possible, the solution to the dispute will take the form of removing a measure not conforming to the principles of the FTA, or failing a solution, compensation to the affected party. In those instances where the two countries cannot agree on a mutually satisfactory resolution of the dispute after the arbitration panel submits its final report, the aggrieved country can take action of depriving the offending country of equivalent benefits until such time the two countries have reached an agreement.

To date, the effect of the FTA on natural gas trade between the United States and Canada has been minimal as it merely codified an existing market-oriented natural gas trade environment. The long-term benefits should be substantial, however, as the FTA ensures that Canadian gas exports to the United States will be unrestricted in terms of volume and price in the future. This situation should provide a positive effect on Canadian natural gas supply capability, as Canadian producers recognize that they have a long-term, secure, unrestricted market access to the United States. Another benefit of the FTA is that it provides this country with access to secure Canadian natural gas supplies to meet long-term energy needs, even in times of short supply. A secure supply of energy is vital to U.S. national and economic security.

Overall, the FTA removed most of the remaining constraints on access to each country's natural gas resources, transportation, and marketplace.

NORTH AMERICAN FREE-TRADE AGREEMENT

In January 1991, the United States, Canada, and Mexico agreed to hold trilateral negotiations for the purpose of creating a North American Free-Trade Agreement (NAFTA). On June 12, 1991, the three countries began formal talks. On August 13, 1992, an agreement was achieved. This proposed agreement is now subject to legislative approval in the three nations.

The United States wants to use the NAFTA for building on Mexico's market-oriented domestic reforms of the past six years. Mexico has been a natural gas trading partner with the United States for many years, but only for limited volumes. Due to Mexico's efforts to improve its air quality, its industrial growth, and the lack of sufficient pipeline infrastructure to serve that growth, U.S. gas sales to Mexico should continue to grow during the foreseeable future. During the long term, development of Mexico's huge natural gas resources could result in Mexico becoming a major supplier of gas to the United States.

With regard to energy matters, the U.S. negotiators attempted to accomplish the following: (1) permit U.S. and Canadian firms to participate in the exploration, extraction, and distribution of Mexican oil and natural gas, and invest in the Mexican petrochemical industry, which includes the refining sector; (2) seek greater participation in the Mexican oil and gas production sector by allowing direct foreign investment or including the legalization of risk contracts (i.e., contracts that allow companies to share in profits of oil and gas exploration); (3) pursue the elimination of Mexico's two-tier energy pricing policy, under which oil, gas, and electricity are sold within Mexico at prices lower than the prevailing export price; and (4) press for the elimination of Mexican petroleum feedstock sales to petrochemical producers at prices below world levels.

These goals remain unchanged. The initial agreement promotes cross-border trade in natural gas and basic petrochemicals, and provides that state enterprises, end users, and suppliers have the right to negotiate supply contracts. U.S. gas exporters will be able to negotiate directly with end users in Mexico, developing their own agreements. PEMEX, however, will still be the contracting entity for legal purposes. In cases of supply shortages, unlike the Canadian Free-Trade Agreement in which neither party can discriminate between domestic and export customers, Mexico retained its constitutional right to favor domestic customers whereas Canadian and U.S. customers would be given most favored nation status.

OTHER INITIATIVES TO ENHANCE TRADE

While most nations are unwilling or unable to negotiate a free-trade agreement with the United States, most of the industrialized nations of the world have participated in the General Agreement on Tariffs and Trade (GATT). The GATT agreements have influenced world trade in the direction of lowering tariffs and other barriers to trade. The general lowering of tariffs and impediments to trade establishes benefits in terms of more efficient production, better utilization of manufacturing capability, and higher standards of living. These benefits encourage the development of similar low tariff arrangements for the movement of natural gas across national boundaries. Worldwide natural gas trade has grown substantially over the past couple of decades. In 1990, for example, 18 nations exported natural gas to 29 importing nations.

Some type of national agreement is usually required for large capital investments to be made that make international natural gas trade possible. These agreements vary widely in types of products and the detailed trade conditions that are specified. Most free-trade agreements are very broad; however, some international agreements deal only with natural gas and are quite limited in scope. Nation-to-nation agreements often define non-tariff trade barriers such as import licenses, quotas, or labeling requirements.

Bi-lateral treaties are often the means of assuring business that conditions are sufficiently stable to reduce a company's risk for the massive investments required. Therefore, these treaties are often umbrella agreements whereby the private or national companies can execute import/export contracts. Typically, regulatory authorities in the trading nations must approve initially and subsequently monitor import/export projects. Without a national treaty or agreement the participants have no assurance that the contract conditions will be fulfilled.

The contracts under which energy imports/exports are consummated often involve a government company such as PEMEX, Sonatrach, etc. Privately owned U.S. companies' negotiations with foreign national companies often require the back-up of a national level approval of the energy import or export to provide a foundation for the contractual agreements.

THE INCREASED NATURAL GAS TRADE OPTION

The natural gas industry could benefit from increased potential supplies of natural gas and increased markets for natural gas by the broad application of free-trade policies in North America. Impediments to the movement of natural gas across international boundaries restrict the opportunity for the most efficient producer to serve the customer who values the commodity the greatest. Overall efficiency in serving the markets of all of the nations involved is created by permitting gas movements across borders based on economic criteria rather than arbitrary customs or tariffs. The enhancement of the efficiency and effectiveness of the North American gas grid benefits the gas industry and its customers.

Specifically, the free-trade option for Canada is embodied in the Free-Trade Agreement (1987) and remains in operation; the U.S.-Canada cooperation is further defined in the tri-party NAFTA. The Mexican free-trade agreements are defined within the NAFTA framework.

Free-trade considerations bearing on U.S. imports of LNG from Algeria and potentially from Nigeria, Venezuela, Trinidad, and other countries are implemented in bi-lateral negotiations and detailed in the individual company level contracts. For the LNG trade there is no omnibus agreement affecting all imports by the United States. Free trade is also an important aspect of natural gas exports. Although the current export programs provide natural gas only to Canada, Mexico, and Japan, expansions of this trade in the form of LNG to other Pacific nations is possible in the time horizon of this report. The benefits of free trade are also applicable to these potential agreements.

MAJOR BENEFITS OF FREE TRADE IN NATURAL GAS

Free trade permits economic factors to govern the movement of natural gas across borders and throughout the free-trade region. The dominance of economic considerations allows the integrated natural gas production and transmission systems to operate at peak efficiency. In addition, the increased continental gas utilization improves the quality of the environment from both air quality and waste product viewpoints. Additional benefits accrue to gas users as technological improvements and more efficient gas grid services are made possible by enhanced continental trade.

Geologic and geographic factors are fundamental in determining the cost of natural gas production and transmission. Free trade would permit the lowest cost gas to serve each market. In effect, this improved efficiency means that end users have access to lower cost energy and so are able to produce goods and provide services at a lower cost.

Specialized market conditions often require natural gas to be delivered on a highly seasonal basis or require other special delivery considerations. Free trade allows the specialized requirements of end users to be subject to the broadest possible competition in the bidding to provide the desired service. For example, an end user who requires uninterrupted gas supplies, regardless of temperature, can consider the widest possible variety of services that would provide his desired level of assurance.

One feature of the North American gas grid flexibility that enhances the overall system efficiency is the service to an end user by means of displacement. Displacement permits the sale of natural gas from a wellhead in Alberta to an end user in Florida without having the full, physical transportation from Alberta to Florida charged to the cost of the sale. The Alberta producer might deliver the gas volume to Chicago to offset a delivery due from the Texas Gulf Coast. At the Texas Gulf Coast, additional gas may enter the pipeline to Florida. The transportation cost for such a hypothetical sale might be only from the wellhead to Chicago and from the Texas Gulf Coast to Florida. The reduced transit costs allow many more producers the opportunity to bid for gas sales in remote areas. The effect of displacement is a significant increase in the ability of the industry to minimize transportation costs.

Surges in demand can create market imbalances that are typically expensive to satisfy. For example, possible short-term surges in demand may require that additional production or transmission capacity be installed. The broader network capability from the entire free-trade region is more capable of dealing with market fluctuations than is a smaller, less flexible system.

The increased availability of natural gas in a free-trade region strengthens markets and makes gas more available to potential end users. Furthermore, the enhanced efficiency of the natural gas network will, of itself, make gas the fuel of choice in some otherwise marginal markets.

THE COST OF FREE TRADE IN NATURAL GAS

The major benefits of free trade in natural gas are more applicable to the end user. He receives gas supplies at a generally lower cost because of the ability of more producers to bid for the sale and the flexibility of routing the flow of that gas to the end user. Clearly, some of the economically marginal producers may suffer the loss of sales and some of the overburdened transmission routes may become less utilized. The efficiency gains in the North American gas grid will be achieved at the expense of those least able to survive in the more broadly competitive market place.

From the domestic U.S. labor point of view, it may be that increased availability of inexpensive, reliable natural gas service may increase the efficiency of Mexico factories that compete with U.S. factories. Improvements in the reliability of energy supplies of the Mexican factories would have the effect of exporting jobs to Mexico.

In the past, each nation has planned to optimize the natural gas production and delivery system within its own boundaries. One manifestation of these optimizations has been the creation of subsidies or special benefits to certain groups. Certain classes of producers receive subsidies, such as the Section 29 or other tax credits. While the concept of free trade does not necessarily prevent such subsidies, the continuation of these benefits is less likely to occur in the context of the free-trade region. This broader perspective is likely to cause certain subsidized groups to lose their preferential treatment. For such groups, the loss of preferential treatment may not be offset by the benefits of increased efficiencies of the North American gas grid.

RECOMMENDATIONS

Free trade would move toward the economic integration of gas sales in participating nations and provide more uniform sales and buying opportunities in the nations involved.

- The gas industries in each nation would be stronger and more efficient.
- Certain parts of the industry would suffer from competition; others would benefit.
- Loss of protective barriers could be traumatic for certain politically sensitive sectors.
- Modified free trade, i.e., removal of **many** of the national barriers to trade is easier to institute, e.g., U.S.-Canada Free-Trade Agreement, North American Free-Trade Agreement.
- Failure to challenge the Mexican constitutional limitations on oil and gas reserves development will work to the long-term disadvantage of increasing North American natural gas consumption.

Specific actions to implement free-trade principles with respect to natural gas would include:

- Encourage NAFTA and/or subsequent efforts to fully establish free-trade principles with Mexico and Canada for imports and exports.
- Support the abolishment of federal regulatory oversight over natural gas imports and exports with those countries with whom we have negotiated a "bona fide" free-trade agreement—the other country should take a reciprocal action.
- Endorse federal import approvals for bilateral natural gas trade agreements.

IMPACT

Under a low import supply scenario, the importance of NAFTA is somewhat diminished, because this country's reliance on imported supplies in its natural gas supply mix continues to be relatively low over the forecast period. However, under a high import scenario, successful completion of a NAFTA and other measures to expand free-trade principles would be very important due to this country's increased reliance on imported gas supplies. Artificially constrained natural gas trade could reduce availability of gas in the United States by 2 trillion cubic feet annually by 2010.

CHAPTER NINE

CONTRACT RELATIONSHIPS

The question addressed in this chapter is: How can natural gas contracting practices aid in the transformation to a largely deregulated market and help ensure consumers and the nation an adequate and reliable supply of natural gas? The potential for natural gas to make a larger contribution to the nation's energy supply and to aid in sound environmental policies has never been greater. With the implementation of the Federal Energy Regulatory Commission (FERC) Order 636, the Commission is completing the restructuring of the industry begun in the early 1980s. This restructuring will provide for a competitive market in not only the spot sales market, but also in the long-term gas sales market. For such a transition to succeed, new market practices must be developed to replace regulations. Natural gas contracts are the lynch-pin of this new competitive market.

In a free-market environment, the reliability and enforceability of business transactions are based on privately negotiated, commercial contracts. Historically, the wellhead and the burnertip ends of the natural gas industry have been insulated from market reality.

The foundation for supply reliability has been the certificated service obligation, rather than an arms-length contract. Pipeline gas sales contracts merely formalized the service obligation and detailed operating parameters and responsibilities. Even as the pipelines have evolved primarily into transporters rather than sellers of gas, customers have still been able to fall back on pipeline supply when necessary. The industry is now shifting away from mandated obligations and moving toward a free market environment. Buyers and sellers must now supplant this regulatory contract with separately developed agreements that provide for the parties' needs. For example, one of the specific objectives of FERC Order 636 is "to create a regulatory environment whereby gas purchasers and gas sellers can structure their relationships as much as possible by private commercial contracts." Accordingly, the reliability of gas delivery will be based on privately negotiated gas supply contracts, and the underlying transportation agreements, which will be subject to pipelines' FERC-approved tariffs.

This continuing shift in the regulatory framework of the industry is transferring supply risk and contract risk from the pipeline to the local distribution company (LDC) or end user. While spot or short-term contracts may have provided adequate supply reliability in the past, new types of contracts will be needed to accommodate the free market for gas supplies envisioned in Order 636. This chapter addresses the structure and diversity of contracts now being entered into between buyers and sellers in the natural gas industry.

HISTORICAL OVERVIEW

In the 1930s, Congress began to investigate the complaints of consumers, distributors, and producers that the unregulated pipelines were engaging in monopolistic practices that were detrimental to the other industry participants.

Congress directed the Federal Trade Commission (FTC) to investigate. In 1935, the FTC issued its report, substantiating the claims that pipelines were engaging in abusive and discriminatory practices with regard to their transportation function. The FTC concluded that the unregulated pipeline transportation of gas was a natural monopoly, which exercised monopoly power over distributors and monopsony power over producers.

Congress initially attempted to grant a federal agency the power to regulate interstate pipelines as common carriers. Designating natural gas pipelines as common carriers would have required the pipelines to provide equal access to their facilities to all third parties. The result would have been to allow thousands of producers to freely contract with hundreds of gas distributors and millions of consumers for the sale of gas in a competitive market. Natural gas pipelines vehemently objected to being regulated as common carriers and instead sought and ultimately won, with the enactment of the Natural Gas Act (NGA) of 1938, regulation that although burdened them with a public service obligation, protected them from competition in both the transportation and sale of gas.

The purpose of the NGA was to ensure consumers access to adequate supplies of gas at reasonable prices. The Federal Power Commission (FPC) was granted the right, under the NGA, to regulate sales for resale in interstate commerce, transportation in interstate commerce, and the facilities used for such sales and transportation. The regulation as it developed did not require or encourage pipelines to provide third parties access to their facilities. Without third party access, competition would not arise and the foundation for market distortion was laid. LDCs purchased all their supply requirements from the pipelines and in turn resold the gas to industrial, commercial, and residential end users. LDCs' contractual arrangements were in large part set by the pipelines' tariffs as approved by the FPC, and not by the private negotiations of the parties.

The second major event, which would further distort the market, occurred in 1954 when the Supreme Court decided the infamous *Phillips Petroleum Co. v. Wisconsin*. With the *Phillips* decision, not only was access to gas restricted, and gas sales from pipelines to LDCs regulated, but now producer sales of interstate gas became regulated and a long and torturous history of producer price regulation and regulatory interference with producer-pipeline contracts was begun.

After *Phillips*, the FPC did not limit itself merely to dictating producer prices. The FPC regulated BTU (British thermal unit) adjustments, whether or not producers could take gas for their own use, whether they could charge a pipeline for services rendered by the producer, whether contracts could contain take-or-pay provisions, and whether a producer's intrastate gas was redesignated as interstate gas if it was ever commingled with interstate gas. This pervasive regulation caused contract distortions since parties were not free to look after their own best interests. As for price regulation, initially the FPC set the maximum price producers could receive based on the historical exploration and production costs of a company. This effort only resulted in bureaucratic gridlock. In six years, the FPC had completed only 10 cases out of approximately 2,900. Next, the FPC tried the area rate approach. The country was divided into several producing areas, each subject to a different price ceiling. The price set for an area was based on the average exploration and production costs associated with that area. Each area rate proceeding required approximately ten years to complete. In the meantime, the FPC set interim area rates based on historical contract prices. The interim rates were enforced by the FPC by its refusal to certificate (approve) a new producer sales contract unless it was compatible with the interim rate. Without a certificate, a producer could not produce its gas into interstate commerce. Distortions in the market price for gas grew because area rates were based on average historical costs of the 1950s and assumed that exploration and production costs would remain about the same for the 1960s and 1970s. Exploration and production costs actually increased during this period, and thus the regulated rate fell well below the actual costs to bring on new supplies.

Vintaging was also a feature of price regulation that led to market distortion, because area rates varied by the vintage of the gas. The FPC eventually recognized that the cost of gas exploration, development, and production was greater in later years than in earlier years and, to compensate producers for the increased costs, established rate ceilings for new gas that were slightly higher than previously discovered "old" gas. Pipeline tariff gas was priced on the average cost of gas—a blending of old gas prices and new gas prices. Once a pipeline's average price fell below the price that would have existed in an unregulated competitive market (as seen in the unregulated intrastate market), the wrong market signals were sent to consumers and ultimately the demand for gas rose well above that which would have existed in a competitive market.

Under the NGA, the relationship between a pipeline and a producer was governed both by the provisions of a long-term contract and the requirement that the FPC grant prior permission to both buyer and seller before the relationship could terminate. As discussed above, the relationship between a pipeline and an LDC was governed by a long-term contract as controlled by a pipeline's tariff and the obligation to serve the public, which also required a continuation of service after contract termination. Producer contracts were typically for a term of 20 years. Later regulations of federal offshore production required a contract term of 15 years or longer. The only relief for a producer or pipeline from the obligation to deliver and take was if the FPC granted an abandonment. Abandonments were almost never granted unless all the dedicated reserves were depleted.

The pervasive regulations and inability to freely contract caused producers to significantly curtail their efforts to find gas for sale to interstate pipelines and instead they increased their efforts to find and produce gas in the unregulated intrastate market. Additionally, these regulations caused LDCs to increase their demand for artificially low priced gas. Regulation of producer prices, the inability of producers to freely contract to sell their gas to any pipeline of their choosing, and the inability of gas to move from the intrastate market to the interstate market and back led to the severe gas shortages in the interstate market in the 1970s.

Once the FPC recognized that the shortages were a result of its policies, it attempted to "regulate better." The FPC moved from area rates to national rates. This approach resulted in establishing rates based on more current cost information. Since the rates were national, only one proceeding lasting approximately two years was necessary. Additionally, the FPC assumed that costs would increase at a constant rate over time so that the national rates were based on historical costs plus an escalator. The new national rates were about five times higher than the old area rates. However, even this attempt by the FPC to "regulate better" was flawed because the vintaging concept was retained, and the methodology used to calculate the national rates would have resulted in rates that were too high for some years and too low for others.

The attempt to "regulate better" was not confined to the efforts of the FPC. In 1978 Congress entered the fray once again with the passage of the Natural Gas Policy Act of 1978 (NGPA). The Federal Energy Regulatory Commission was established as the successor to the FPC. Congress recognized that regulation of the gas industry had failed. Thus, a major component of the NGPA was the mechanism for partial deregulation. It allowed for price deregulation and abandonment of some types of gas, but retained price and abandonment control for other types of gas (i.e., vintaging was retained). An estimated one-half of the nation's gas supply was to deregulate. The other half of the nation's gas supply was never to be deregulated, as it was presumed this gas, produced from old reservoirs, would eventually be depleted. The producer-pipeline contracts in place in 1978 were often amended to add deregulation language in an attempt to outline the parties' rights and obligations in a partially deregulated environment that was not envisioned when the contracts were first negotiated. Congress also attempted to "regulate better" by limiting the demand for gas. Pipelines and distributors were forced to charge higher prices to many industrial consumers. Additionally, in a companion piece of legislation, the Power Plant and Industrial Fuel Use Act of 1978, many industrials and electric utilities were prohibited from using natural gas. Again, contracts were interfered with or tossed out.

Congress' attempt to "regulate better" only exacerbated the gross distortions in the marketplace and adversely affected all segments of the industry from 1978 to 1987. Consumer prices rose well above those that would have existed in a competitive market. The parties' contracting practices reflected the hand of regulation and not the ability of the parties to make business decisions based on market realities. Because market signals were so perverted by regulations, many pipelines thought they were still facing a shortage in 1984 when there had been evidence of a surplus in 1978. Since pipeline contracting practices were significantly determined by regulations, when shortages were perceived, pipelines committed to buy more gas under contracts with higher take obligations. When prices began to rise and certain consumers were denied the right to use natural gas, demand fell. At the same time, the supply of gas was rapidly increasing. This surplus, which became known as the "gas bubble," forced the shut-in of large amounts of gas and drove many producers out of the industry. The bubble is now widely recognized to have appeared around 1984. Pipelines began accruing huge liabilities to producers under take-or-pay contracts. Under these contracts, the pipelines were committed to take the gas from the producers or pay for the gas if not taken. Since prices had risen and demand had fallen, the pipelines had limited markets in which to resell the gas at the prices called for in the producer contracts. Contracting practices, constrained by regulatory fiat, now posed major obstacles to the transition to a competitive marketplace. Pipelines ended up committing to buy such large quantities of gas from producers that, even with access to large volumes of old low priced gas, the average cost of the pipelines' tariff gas exceeded the price of alternative fuels or alternative sources of gas. Congress did not understand that regulation insulates participants from the discipline of the market. In its attempt to increase supply and decrease demand it disregarded "real world" market forces, which ultimately triumph even in the most regulated of markets. Last, and perhaps most importantly, neither Congress nor the FPC nor the FERC, at first, understood the ability of each market participant to protect its own best interests by contract.

Pipelines began to enforce the minimum bill provisions the FERC had previously authorized in their tariffs in order to limit their customers' ability to reduce purchases or to switch their suppliers. The pipelines also initiated special marketing programs and limited transportation programs designed to recapture customers lost to alternative fuels. This meant that pipelines sold gas at below cost to alternative fuel customers and continued to sell gas at above spot market price to their captive customers. Because of the hardship on the LDCs' customers, this pipeline practice motivated the FERC, in 1984, to issue Order 380 declaring the variable cost component of minimum bill provisions anti-competitive. This released customers from the obligation to take-or-pay for minimum volumes of gas and reduced significantly the economic penalty a pipeline customer had to pay to switch to a lower cost source of supply. This Order was the first signal of the FERC's move toward allowing market forces to work. FERC Order 380 was a significant blow to the pipelines that did not get offsetting contractual relief from producer take-or-pay obligations. Pipelines, in an effort to retain markets, created special marketing programs whereby producers' gas would be released from the pipeline purchase contract and sold at market prices to fuel switchable customers. Producers moved their gas, pipelines obtained take-or-pay relief, and fuel-switchable customers received competitively-priced gas. The special marketing programs of the mid-1980s marked the dawn of the spot market but because pipelines purposely limited buyers' and sellers' access to transportation, few in the market could take advantage of the emerging spot market.

The FERC began to recognize that the limited access to transportation that industry participants had was a major impediment to competition in the marketplace and the growth of the spot market. In 1985, the FERC issued Order 436 to provide open access transportation to all industry participants. Until 1985, the FERC and its predecessor, the FPC, had largely ignored the transportation function that the FTC had determined to be monopolistic. The FPC, and heretofore the FERC, had focused on regulating the gas sales market and had sustained an artificial pipeline monopoly in the inherently competitive gas sales market. As a result of Order 436, pipelines could choose to be open-access transporters and were encouraged to do so by numerous regulatory means. The ultimate result of Order 436 was to force the pipelines to compete with others in the gas sales market. Because interruptible transportation was becoming available, and because of the market perception that gas prices would continue to decline, many purchasers eagerly looked to short-term contracts, characteristic of the spot market, to meet their supply needs.

The emergence of the spot market had a tremendous impact on the gas industry. Because of the distorting effects of gas regulations, excess gas supplies were available when deregulation began to occur. A market was needed to sell the excess gas. Much like nature's abhorrence of a vacuum, free markets abhor unfulfilled demand. New markets were quickly created to sell excess gas. New participants entered the market and new pricing signals were created for those markets. With an unregulated market and excess supplies, the potential existed for prices to fall, which they did. The importance of the spot market is that for the first time in the modern history of the U.S. gas industry, market forces were allowed to work. Gas market participants were finally able to make gas decisions based on market mechanisms, not regulatory fiat.

In 1986, the FERC removed yet another regulatorily created market impediment by issuing Order 451, which allowed producers with certain contractual provisions to renegotiate low-priced old gas up to a set NGPA maximum lawful price or to terminate the gas sales agreement with the pipeline. This freed up more gas to go into the spot market and allowed the price for most old gas to increase up to the market price. In 1987, in an effort to deal with the take-or-pay problems of the pipelines, the FERC issued Order 500, which allowed pipelines to recover take-or-pay costs and other contract reformation costs from their customers and implemented a take-or-pay crediting mechanism on producer gas transported by interstate pipeline.

On February 5, 1988, the FERC issued Order 490, which allowed for automatic abandonment of certain producer sales if the contracts were terminated or modified by mutual agreement or if the sales or purchase obligation had been unilaterally reduced, suspended, or terminated by the exercise of contractual provisions. This allowed gas to move where the market dictated and no longer held producers hostage to pipelines once contractual obligations ceased. In July of 1989, President George Bush signed the Natural Gas Wellhead Decontrol Act into law, effectively setting the stage for the final phase-out of all regulatory wellhead price controls by January 1, 1993.

Producers were gaining control of their gas production as their gas decontrolled, contracts expired, and gas reserves were automatically abandoned. Consumers were benefiting from rapidly falling gas prices at the citygate or industrial burnertip. The pipelines were evolving from a primary role as merchants to a primary role as transporters, even though the pipelines' service obligation continued to obligate pipelines to provide backup gas supplies for many customers.

Competition in the marketplace was thriving, but since most of the available transportation was interruptible in nature, the sales contracts that were developed required only minimal obligations by each party. Generally, sales under these spot market contracts were for a period of one month, and could be interrupted, suspended, or terminated by either party for almost any reason. Suppliers could rarely guarantee delivery, and the buyers would rarely pay the cost of a guaranteed delivery since they could always fall back on the pipelines' certificated service obligation for system supply.

Despite the general lack of availability of firm transportation by the mid to late 1980s, new forms of long-term contracts were reappearing. Many were one- to three-year commitments, usually to local distribution companies, some of which had converted a portion of the firm sales requirements to firm transportation rights under Order 436. These LDC contracts were for baseload supplies, and were generally priced based on a published index price plus some premium to compensate the seller for a supply commitment. Other even longer-term contracts were developed to meet the needs of a growing new gas market, the non-utility electric generator. The needs of this market sector renewed the discussion of firm price commitments, unrelated to the spot market. The needs of the market participants demanded the availability of long-term contracts.

Recognizing that long-term contracts were difficult for parties to negotiate in part because of the difficulty in obtaining firm transportation capacity on pipelines, the FERC issued Order 636 on April 8, 1992. If it is substantially upheld by the courts and left to stand by Congress, it will be a true watershed for the industry. Order 636 requires a pipeline to unbundle its sales function from its transportation function and charge a customer for only those services for which the customer actually contracts. The open-access transportation of Order 436 and the unbundling of pipeline sales and transportation services under Order 636 will allow the long-term gas market to develop as did the spot market in the 1980s. Order 636 will increase the importance of contracts. It will also allow each seller and each buyer to approach contracting in light of their individual operating needs, personnel capabilities, pipeline transportation tariffs and rates, and applicable state and federal laws and regulations. The parties at long last are free to tailor their contracts to their individual industry and circumstances. Longer-term contracts can offer prospective suppliers a secure market, prospective purchasers a firm supply, and all parties administrative efficiencies. While the trend in the 1980s was for short-term spot contracts, the trend in the 1990s will be towards contract diversity including diversity in contract duration.

COMPARISON WITH OTHER MARKETS

Participants in the natural gas industry sometimes view the current market transformation as unique to natural gas. This unperceptive view belies what has occurred in the markets for fuels that compete with gas. With the market changes of the last decade, today's energy supply contracts for oil, coal, and gas are markedly different from those commonly used in 1980.

Producer sales of oil became regulated in 1973 as a result of the Arab oil embargo, and they deregulated in 1980. This once highly integrated industry began to break up in the 1970s as higher prices attracted the "independent" oil and gas producers into the market, and nationalization by foreign countries of their natural resources forced out majors and substituted state-owned oil companies. A vigorous spot market was quick to develop, followed by a futures market that is actively traded today. Oil is easily transported (e.g., existing pipelines, barge, truck) and easily stored—this aided in the development of oil as a commodity. Oil sales contracts have, by and large, become simple, short-term contracts reflecting oil's evolution to a fully traded commodity like pork bellies, copper, or gold. Current contracts for the sale of crude oil are commonly 30-day evergreen agreements. Even when suppliers and purchasers enter into long-term oil supply contracts today, these contracts are often only one to three years in length and contain pricing provisions that allow the price to be market responsive.

The coal market has had strong contractual ties between suppliers and purchasers as evidenced by the predominance of long-term contracts in the coal market. The coal industry, like the gas industry, also saw take-or-pay contracts litigated and abrogated. In reaction to the price volatility in the coal market, many coal supply contracts now provide for diverse and flexible pricing mechanisms. Even with the emergence of flexible pricing provisions in long-term contracts, there is a lessening of reliance on long-term contracts. This is evidenced by the emergence of the spot market for coal, which now accounts for roughly 20 percent of all coal sold. Some industry analysts predict this may increase to 35 percent in a few years. Coal has no futures market. Coal is easily stored and relatively easy to transport (e.g., existing railcar, barge), yet the coal market is not as competitive as the oil market because there are fewer suppliers, and because the buyers are, by and large, regulated electric utilities—a very narrow end market as compared with the end markets for oil.

Electricity differs from coal, oil, and gas, in that it remains a highly integrated industry. Wholesale utility sales to other utilities remains regulated by the FERC pursuant to the Federal Powers Act. Retail sales are regulated by state public utility commissions. The obligations of the parties are generally defined by regulations, not contracts. Besides utility-owned generating facilities, cogenerators, small power producers known as "qualifying facilities," and independent power producers have emerged as a result of legislation enacted to discourage the use of oil to generate electricity. These non-utility electric generators have created new generating capacity resulting in competition in the wholesale market. However, much like the early 1980s in the gas market, this excess generating capacity has difficulty being accessed by potential buyers. Utilities are generally reluctant to transport, or "wheel" electricity for non-utility generators. The FERC has been reviewing whether the method of transmission for electricity should be changed. A voluntary wheeling scheme akin to Order 436 in the gas industry is being considered. There is discussion of "unbundling electric rates" in order to separate the costs of various service elements. The brokering of electricity has begun on a small scale. Electricity is beginning to be perceived as a commodity. The idea of a spot market and a futures market is gaining ground. However, development of a competitive market for electricity lags substantially behind that for oil, gas, and coal.

In each of the above discussed energy sectors, contracting practices of the past have changed or are beginning to change as a result of partial or complete deregulation of energy sources, new participants in energy markets, continuing international competition for oil, the emergence of a competitive North American market for gas, continued increasing inter-fuel competition among gas, oil, coal, and electricity, and continuing and expanding access to transportation facilities. This portends a move away from a predominance of long-term contracts, especially nonmarket-responsive long-term contracts, in all energy markets. As each energy sector evolves it must grapple with the need to develop contracts that provide an equitable balance between buyers' needs and sellers' needs and maintain this balance during the term of the contract. If gas is going to gain market share from these competing fuels it must develop contracts to strike this balance posthaste.

DIVERSITY IN THE NATURAL GAS INDUSTRY REQUIRES DIVERSITY IN CONTRACTS

Today's natural gas industry is incredibly diverse. There are an estimated 5,000 independents and major producers. Since the emergence of the spot market in the mid-1980s, numerous non-affiliated gas marketing companies have entered the market. A few of these have developed into major market players. Today, there are over 80 interstate pipelines and over 150 intrastate pipelines. Nationwide, an estimated 1,400 LDCs serve four million commercial customers and tens of millions of residential customers. There are at least 275,000 industrial end users of gas. The industrial sector uses 17 percent of the gas for feedstock, 32 percent for boiler fuel, and 51 percent for process heat. Industrials also have 1,600 cogeneration projects, the vast majority of which consume gas. Other independent electric power producers that consume gas for baseload and peaking needs number almost 4,000. In the United States, there are approximately 3,500 electric utilities that use natural gas to provide 9.5 percent of the electricity generated nationwide. Because of the diversity in the industry participants, generalization about the contract needs of any segment of the industry can be misleading, or simply incorrect. For example, all LDCs do not require wide swings in gas deliveries, and all gas-fired cogenerators do not require pre-established, firm pricing provisions. Each buyer and each seller has a unique set of requirements, preferences, and objectives, which are matched by the efficient operation of an unregulated, unbiased market for the sale and purchase of natural gas.

Today, natural gas contracts must be designed to accommodate the diverse production, consumption, and transportation needs of an industry in transition. As the deregulated gas sales market continues to mature, the unambiguous trend is toward more contract options and flexibility.

Contracting Considerations

Gas Producer/Supplier

A producer, when contracting, considers more than just the physical capabilities of a well or field. A producer also considers economic, regulatory, and contractual obligations such as:

- Physical characteristics of the producing reservoir (must-flow water drive reservoir vs. discretionary pressure drive reservoir; long vs. short life reserves)
- Physical characteristics of the produced gas and the associated costs to obtain pipeline quality gas (impurity content, liquids content, heating value)
- Contractual and legal considerations (correlative rights issues, drainage, balancing agreements, joint operating agreements, lease provisions, well allowables)
- Economics of gas development and production (netback value to the wellhead,

associated revenue from oil and liquids production, tax considerations)

- Location of the production (proximity to transportation, access to multiple transporters, cost of transportation to market, processing costs)
- Financial and strategic position of the producer (large vs. small, cash flow requirements, conservative vs. aggressive)
- Location of market or sales point (marketcenter, pooling point, citygate, tailgate of plant, wellhead)
- Price risk management (ability to use futures market).

Gas Consumer

Consumer gas contracting considerations are diverse. Gas usage may or may not be at a uniform daily rate. The demand for gas in the home and commercial space heating market varies according to weather. Industrial gas demand is a function of the operating rate and schedule at each plant or factory. The demand for gas by electrical generators can swing up or down based on the demand for electricity, and the cost, availability, and acceptability of alternative fuels. The contracting policies of gas consumers are based on an innumerable set of factors, including:

- Priority of need (human needs with no possibility of a readily available alternative vs. easy access to alternative fuels or low shutdown/curtailment costs)
- Seasonality, control of demand variability (weather-related vs. operational control)
- Alternative supply (multiple gas pipeline connections, alternative fuels, or feedstock choices)
- Significance of cost component (is natural gas a large or small percentage of gas user's total cost of doing business)
- Planning horizon (is gas user able to plan for long-term requirements, or is planning limited to the short-term)
- Environmental considerations (is the gas user encouraged by economics, regulation, or corporate strategy to use gas as a clean fuel alternative)
- Delivery point considerations (is the gas supplied to the burnertip, citygate, or at a pooling point or market hub, or at the wellhead)
- Price risk management (ability to use futures market).

In a deregulated market, it is the contract that reconciles the various needs of gas producers with the various needs of gas consumers.

Gas Marketers/Supply Aggregators

Gas marketers emerged with the creation of the spot market. Gas marketers buy from producers and resell to LDCs, electric generators, and industrial end users. Marketers stepped in to fill the supply aggregation function left void as pipelines became primarily transporters. Marketers must balance the needs of gas producers against the needs of gas purchasers. An additional consideration for a natural gas marketer when contracting for gas supplies is to what extent the producer's gas supply will augment the marketer's presence on a pipeline system. Likewise, a marketer will more than likely confine its pursuit of resale customers to those customers with market area delivery points on pipelines where the marketer has aggregated supplies.

Gas Supply Contract Provisions

Although each negotiated gas contract is unique, there are several provisions that are essential to any contract. These provisions are crafted by buyer and seller during their negotiations and cover price, quantity, term, and receipt and delivery location. Other common provisions included in most gas purchase or sales contracts are a definition section, a seller's reservation clause, gas quality specifications, measurement standards, effect of laws and regulations, warranty of title to the gas, force majeure, billing, payment, assignability, and dispute resolution procedure. Some of the variables in these provisions that may be negotiated by buyers and sellers are highlighted as follows:

- ***Load Flexibility*** – How often can the delivery rate be changed (e.g., never, annually, seasonally, monthly, daily, hourly)? Who has the right to change the delivery rate (supplier, customer, both, neither)? How much notice is required prior to a delivery rate change? By how much can the delivery rate be changed?

- ***Pricing Mechanism*** – How often can the price change (e.g., never, annually, seasonally, monthly, daily)? What can trigger a price change (e.g., price of consumer's product, change in gas price relative to alternative fuels, labor costs, inflation, annual pricing mechanism, base price plus escalator)? Who can trigger a price change (buyer, seller, regulatory agency)? What is the basis for establishing price (e.g., fixed price, spot market, futures market, index of alternative fuels, predetermined escalation, etc.)? How is price risk shared (e.g., index prices, index plus prices, price tied to citygate prices, prices tied to a producing region or tied to the price of an alternative fuel, prices tied to proceeds on resale of product or constituent thereof, percentage of proceeds price, price caps, price floors, price indexed or tied to the futures market, or a combination of methods)?
- ***Reliability of Deliveries*** – What excuses (if any) are acceptable for the failure to make or take delivery (e.g., failure of transportation, freezing of wells, depletion of reserves, factory downtime, labor strikes)?
- ***Contract Security*** – What are the consequences for failure to make or take delivery? Is the obligation absolute, is liability limited to the cost of making alternative supply arrangements, or to a stated damage amount, is the contract interruptible by either party for any reason, or is the contract limited by the occurrence of unusual economic conditions not contemplated by the parties at the time of execution of the contract?
- ***Payment*** – When is payment due (e.g., total or partial—up-front prepayment, due 30 days after receipt of invoice, or 30 days after receipt of pipeline's statement)? On what figures is payment based (e.g., on estimated deliveries, nominations, actual deliveries)?
- ***Term*** – The length of a contract can vary from days to years. Currently, contracts generally fall into three groups: short-term spot contracts (one month to one year), longer-term or intermediate contracts (one to five years), and long-term contracts (five to twenty years). Even within these three categories, a contract can provide for an extension of the term, sometimes this can be an automatic extension for an additional period or an automatic extension from period to period. These automatic extensions may be triggered by the buyer or seller. The term could be left indefinite with the right of one or both parties to terminate upon appropriate notice or upon the occurrence of some event.
- ***Dispute Resolution*** – If a dispute arises as under the contract what nonjudicial remedies exist (i.e., mediation, arbitration, private mini-trials, private judging, or using neutral experts)?

Back to Basics—Understanding the Consumer

In order to understand how the needs of gas purchasers (i.e., electric generators, local distribution companies, industrial end users) can be met, it is helpful to examine their different segments.

Electric Generators

Electric generators fall into two broad categories—utility generators and non-utility generators.

Electric utilities are regulated as monopolies by both state public utility commissions and the FERC. Electric utilities are granted franchises that define their service areas. Though the generating function of an electric utility is no longer a monopoly, the transmission and distribution sides of an electric utility remain monopolies.

The needs of electric utilities vary widely. One utility may be adding gas-burning capabilities to an existing generating station that formerly burned only residual oil in order to meet new state or federal environmental laws. Another utility may need to build new peak load generating facility. Utilities with gas-fired facilities may choose to buy a portion of the gas supply under long-term contract and a portion of the gas under short- or mid-term contracts or spot purchase.

Gas suppliers must understand the way a utility operates its different generating units. A utility has three types of units—base load, cycling, and peaking. Base load units operate almost year round. Cycling units operate when electricity load changes rapidly. Peaking units are designed to operate only during times of maximum electricity demand. It is very difficult to predict when a particular generating unit will be called upon. Start-up times for units can range from *ten minutes* to eight hours. Thus, electric utilities require contracts that allow for large quantities of gas delivered in short periods of time with little or no advance notice. They have wide swings from hour to hour or day to day. Electric utilities want contracts that provide them with the ability to sell gas supply on short notice to third parties, or contracts in which the gas supplier is free to market its gas to third parties subject to the utilities' right to recall when the utility is not purchasing. Utilities want the contract flexibility to increase or decrease gas takes as electric load swings dictate. Some gas utilities have suggested the creation of "gas pools," which operate like electric power pools in that the pool plans and allocates deliveries of gas to various customers as demands dictate. Producers could offer burnertip contracts wherein the producer secures both the firm transportation and the supply and offers the bundled service to the electric generator under terms that resemble coal contracts. The fixed payments for transportation demand or reservation fees represent risks to electric generators. If a producer contracts for firm transportation and then uses the transportation when the generator is not taking, a risk-sharing mechanism could be worked out. Or if the electric generator contracts for the firm transportation, it could allow an LDC or other third parties to utilize the firm service when the generator was not.

Many electric utilities have voiced their concerns about entering into long-term fuel supply contracts. They point to the take-or-pay problems they experienced with the coal contracts because prices were not tied to some type of market indicator, which would have allowed prices to change as market conditions changed. Many electric utilities point out that there is no need for long-term oil supply contracts and often no need for long-term coal contracts as both fuels are available in the spot market. When drafting a gas supply contract most electric utilities want indexed prices. The index could be tied to the utilities' alternative fuel prices, gas prices in the consuming area, or gas prices in the producing area. Another alternative for accommodating price concerns is to provide for price reopeners for both parties, with the option to terminate if the parties cannot agree to price. Arbitration provisions in lieu of automatic termination rights may be a good idea, especially if the contract is used to obtain project financing. Many utilities expressed dismay with the rigid contract provisions of the past, which failed to recognize everyone's inability to accurately forecast future market conditions. A few utilities want contracts with base prices below spot market prices, arguing that long-term assurance of a market for gas has value. While electric utilities may not appreciate the royalty problems some producer-supplier might incur with below market pricing provisions, suppliers need to recognize that this sentiment is held by some customers. The better argument may be that both the utility and the supplier are receiving an equal benefit (secure market—secure supply) and thus price the gas at its commodity value, with additional compensation being given to the supplier if additional services are provided. Obviously electric utilities' needs differ from those of LDCs or industrial end users. The contracts offered by suppliers should reflect these different needs and not be carbon copies of the contract that satisfied an LDC.

Non-utility generators consisting of independent power producers (IPPs) that have received special exemptions from regulation under the Public Utilities Holding Company Act and qualifying facilities, as defined under the Public Utility Regulatory Policies Act, are often project-financed and may need long-term gas contracts in order to obtain financing. Also, electric utilities signing electric purchase contracts with these generators may require that long-term gas supply contracts be in place. These long-term contracts often contain indexed pricing provisions that may be tied to the producer price index, or the price could be tied to the price dynamics of the electric utility's source of gas or any other fuel that the utility avoided consuming because it bought electric power from a non-utility generator. Start-up dates for these facilities can be one to five years after the gas supply contract is executed.

More IPPs will build electric generating facilities if current proposed reforms to the statutes are passed by Congress. One proposed legislative amendment would allow IPPs to own and operate generating facilities of all types, sizes, and fuel capabilities. These facilities would not be rate-based but would sell the electric power they generate to public utilities at the wholesale level.

Cogenerators are the second type of non-utility generator that use natural gas. These facilities use either gas turbines equipped with waste heat recovery boilers to produce the steam used to generate electricity, or they use combined cycles, which is the combination of a gas turbine and a steam turbine, to produce electricity. Natural gas has been the fuel of choice for the vast majority of cogeneration projects. The steam is sold to a host business on or near the site of electric generation. Electricity is used on location and/or is sold into the public utility electrical grid system.

Three players are usually involved in a cogeneration project: the developer, the lender, and the natural gas supplier. The developer is concerned that the natural gas be delivered as needed at the cogeneration site. The developer is very careful to create and maintain a margin between the power purchase agreement and the gas acquisition costs so as to provide a means to recoup investment, repay debt, and make a profit. The lender's principal objective is to ensure returning the principal and interest over the life of the project. The natural gas supplier has a strong interest in price. The supplier does not want to be locked into a price that is too low. Transportation costs are also a key issue to all three participants.

Cogeneration natural gas supply contracts are usually long-term contracts, typically ten to fifteen years. Commitment of a source of supply usually comes from one of three categories: dedicated specific gas, dedicated portfolio gas supplies, or a corporate guarantee. Natural gas pricing provisions currently in use include: fixed price provisions, fixed prices with year to year inflation adjustments, and prices tied to some index or price tying mechanisms. Gas price provisions should be constructed to avoid price squeeze on either party.

Because electric generators may require a commitment of gas years ahead of delivery when constructing a new plant or facility, producers may be able to meet this need by pairing the development of a field with the contract delivery date or by timing the blowdown of a field to correspond to the contract delivery date. Producers could negotiate for the right to sell to other purchasers when generator takes are low. Generators could pre-pay for some or all of the gas, which would offset the time delay between commitment of supplies and delivery of supplies.

Local Distribution Companies

LDCs, as utilities possessing exclusive franchises from their public utility commissions (PUCs), are required to serve any person requesting service and must maintain adequate supplies to serve all of their customers' demands. Thus, they are required to accommodate not only the needs of their customers when negotiating a contract but also the requirements of their PUCs. Most PUCs require some form of "least-cost purchasing." Even where there is no formal requirement, pricing provisions are still considered. Some PUCs require the LDC to renegotiate contracts with suppliers or take legal actions necessary to relieve the LDC from existing contract terms, which may be adverse to the interest of the LDC's rate payers. Some PUCs require that an LDC purchase gas from local producers if the cost is equal to or less than the LDC's highest priced source outside of the state. Many PUCs conduct prudency reviews of LDCs. During these reviews, PUCs have disallowed contract provisions when price escalation clauses resulted in uneconomic rates. This means reducing the contract purchase price to reflect market prices. PUCs have also assessed the supply risk associated with an LDC's contract. As the LDCs have moved away from pipeline gas supplies and toward direct purchases from producers or marketers, the risk issue has become more important. Due to the current oversupply, however, this is not as great a concern now as it may be in the future.

With FERC Order 636, LDCs will be assuming the total responsibility for the obligation-to-serve burden that the pipelines traditionally helped shoulder. This is a profound change. Some LDCs will face increasing rates as more and more large industrial end users leave ("bypass") the LDCs' systems and tie directly into pipelines. Also, gas LDCs may face continuing competition in residential home heating and cooling from electricity. With security-of-supply worries, consumer price increases and concerns over potential loss of current or new markets, LDCs will be looking for new gas contracting opportunities.

Many LDCs are using a portfolio approach to contracting. These portfolios include spot market, intermediate, and long-term contracts. Currently, the majority of long-term contracts in most LDCs' portfolios are with pipelines. After the implementation of Order 636, third-party suppliers should be able to effectively compete with pipeline-merchants for a share of the long-term gas supply contracts entered into by LDCs.

Suppliers can offer baseload and peak load contracts that would contain pricing provisions tied to the steadiness of the takes. The baseload, continuous take contract would contain a lower price than the peak load contract. Producers could offer to share in some of the marketing costs that an LDC incurs in trying to retain or capture new home heating or cooling load. In return, the producer could receive a guarantee to be the supplier of the new load at a price designed to allow the supplier recoupment of its investment in the LDC's marketing efforts. In LDC markets where electric competition is great, suppliers should explore special pricing arrangements tied to meet or beat the consumers' cost of electricity, or the supplier could help the LDC offer the consumers special financing for conversions from electric heat or cooling to gas heat or cooling. Additionally, as has already occurred, suppliers can team up with LDCs to promote the use of natural gas vehicles.

With regard to the pricing provisions, the parties can use a broad range of tools to allocate the price risks. Index prices plus a standby charge for peak sales, a base price tied to some escalator and/or de-escalator, perhaps with price caps and price floors, could be utilized. Contracts may contain price reopeners when certain prescribed events occur. For example, the contract price or pricing mechanism could be reopened every five years or only when the price remains at the floor or cap for a consecutive year. Suppliers may also want to explore the possibility of entering into joint ventures with LDCs for the construction of storage facilities. A supplier could agree to pay for part of the construction costs in return for steady takes throughout the year, or for the use of some of the storage capacity for the supplier's own needs, or in return for a price provision in the contract that captures not only the commodity cost of the gas but also the principal and interest on the money contributed by the supplier to build the facility.

Industrial End Users

Large industrials that have fuel-switching capabilities are often driven in their contracting practices by the price of alternative fuels. Some industrials, even those with fuel-switching capabilities, want to develop long-term relationships with suppliers because of planned plant expansions, which would require firm fuel supplies, or because their fuel costs are not sufficiently significant to warrant the administrative burden of remaining in the spot market for their entire gas supply. Industrials that use gas as a feedstock usually view the gas price to be the most critical contract element and may be content to stay in the spot market and hedge their price risks with gas futures contracts. For industrials who only use gas to heat their manufacturing plants, price considerations may be less important than the reliability of supply during winter months or during unexpected cold snaps. Such an industrial may only be interested in a six-month gas supply contract. Or such an industrial may be interested in a five-year heating load contract whereby the gas supplier is obligated to supply up to a maximum daily quantity of gas for a six-month period and the industrial end user agrees to release the producer from the obligation to supply gas during the remaining six months. This arrangement gives the supplier market security and the purchaser supply security while recognizing the supplier's needs to have year-round sales of gas and recognizing the purchaser's inability to purchase gas on a year-round basis.

As in any freely functioning market, the number of possible agreements between buyers and sellers is unlimited.

The conclusions for the gas industry are significant:

- Gas contracts must be flexible to meet diverse customer and supplier needs.
- The ability to meet customer needs will increase customer satisfaction with gas as a fuel or feedstock.
- Customer satisfaction can create a preference for gas and can result in a growing market for natural gas.

IMPEDIMENTS TO CONTRACT DIVERSITY

The impediments to contract diversity fall into two categories. The first is regulatory impediments. The second is a lack of vision on the part of industry participants.

Regulatory impediments may prove to be the hardest to overcome. Both the LDC and the electric generator face regulatory oversight, which often amounts to second-guessing. This review process often subjects contracts to revision or abrogation. Regulatory decisions as to the prudency of an LDC's or electric generator's purchasing practices or plans should be made contemporaneously with the contract. If approved, the contract should remain intact. Regulatory intervention should be precluded when subsequent events are not as originally envisioned.

A second regulatory problem arises during an industry's move from a regulated industry to a deregulated industry. The transition period may require more intervention by regulators at both the state and federal level to ensure that competition develops on equal terms. While this type of regulatory oversight may be good, it continues to create uncertainty in the market. It is imperative that the transition phase at the federal level and the subsequent transition period at the state level be expedited. The sooner the regulatory uncertainty is removed, the sooner industry participants will create *contracts* that will supplant regulation.

The second impediment is a lack of vision by all participants in the market. Gas industry participants need to look at other industries to see what types of services and contract provisions are offered there. For ideas, look to the oil markets and the coal markets, both of which are substantially if not totally decontrolled. Look at the financial markets and markets for other commodities. For too long, gas industry participants, particularly producers, pipelines, and LDCs, have formed the opinion that this industry is somehow unique and that what works in other markets will not work here. The industrials and to some extent the electric generators, having had experience in the coal and oil markets, have had a somewhat broader perspective. All industry participants must take off their blinders and re-examine their needs and the innumerable ways in which these needs may be met. Sellers must know their buyers and their unique needs and tailor contracts to fit these needs. Buyers also must understand a supplier's production requirements, financial concerns, and restraints. If both buyers and sellers look to contracting options as being more than either spot market or long-term take-or-pay contracts, then the industry can prosper.

CONCLUSIONS

Due to the regulatory changes that have occurred in the last ten years, the natural gas industry is clearly less regulated and more market-driven. Increasingly, contracts, not regulation, secure a party's needs and define a party's obligations. With a myriad of participants driven by diverse interests and needs, it is no wonder that regulation of gas sales has not worked.

The first step toward a competitive market is to scale back both state and federal regulations to the minimum necessary to protect public interest. This process has begun. The second step is to support the market's evolution toward more contract diversity. The predominance of short-term contracts in the mid-1980s to early 1990s may diminish during the rest of this decade, but many industry participants will continue to participate in the spot market.

The right of buyers and sellers to match their individual interests is the key to optimum market performance. Contract diversity, unencumbered by the uncertainty of regulatory hindsight, will allow buyers and sellers alike to match their individual needs for price, term, security, load flexibility, and reliability. Neither party will pay or be paid for unnecessary services—nor will either get a free ride. The net result should be an overall synergism as the whole gas infrastructure moves toward more optimum utilization.

The state and federal governments must provide a regulatory environment that encourages sellers and buyers to explore possibilities of using a variety of contracts, the futures market, or other tools to help manage their businesses. Contracts will ultimately reflect the industry's progress and growth. Industry must foster frank discussions among suppliers, purchasers and transporters and provide educational opportunities so that all industry participants have a better understanding of the other participants' operational and business needs. Gas suppliers must learn the customer's requirements and customers must learn the producer's capabilities. This mutual understanding is critical to making a satisfactory contract. As the industry develops the ability to offer a variety of gas contracts, customers' current needs will be met and they will have confidence that natural gas will be a competitive energy source in the future. This should result in an increased demand for natural gas.

The National Petroleum Council should encourage regulators to provide clear opportunities for the industry to use free-market, competitively negotiated, innovative, flexible contracts that meet the diverse needs of all parties.

CHAPTER TEN

TECHNOLOGY ADVANCEMENT

SUMMARY

Natural gas will be available as projected by this study only if technology advancement continues to reduce its cost and make new gas sources accessible to the resource base. Supporting this projected availability is an assessed resource base of 1,295 trillion cubic feet (TCF) of gas, which includes the effects of continued technology advancement. During the past 20 years, this advancement has allowed the technically recoverable resource base to grow at about 0.7 percent per year compound growth rate when compared to a 1972 NPC study of the natural gas resource base.[1] Future growth will be even more dependent on continued technological advances. However, this continued technological advancement is dependent on adequate investment in research and development (R&D). The NPC, therefore, undertook a study to evaluate the current state of technology, identify options to ensure its continued advancement, and list some gas resource opportunities amenable to technological development.

Most advancement in the exploration and production sector of the natural gas industry has been the result of investment primarily by individual companies with some additional support from the Gas Research Institute, the Office of Fossil Energy of the Department of Energy (DOE), and other governmental agencies. While these interest groups have generally maintained investment in supply-related R&D throughout the industry contractions since 1988, there is concern that current industry downsizing programs and capital investment reductions are likely to curtail this effort.

One area that might significantly limit the industry's ability to find, develop, and produce gas is the increasingly difficult technical requirements of compliance with environmental regulations. Many new requirements have been and continue to be placed on the upstream industry, and research is needed to meet these requirements. This is just one example of an area where support and participation of the federal government's fossil energy research and development program could significantly benefit the entire industry without influencing competitive positions and help maintain the level of R&D needed.

Recognizing these areas of opportunity, the NPC recommends that the federal government review its prioritization of fossil energy R&D between the fossil energy resources that are domestically abundant—coal and natural gas. Future prioritization should create a more balanced distribution of federal research investment between these abundant resources and, consequently, allow an appropriate mix of energy sources to develop in the consuming markets in line with the economic and environmental characteristics of the fuels. This will be particularly critical as the independent producing sector provides an increasingly larger share of gas supply in the future.

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[1] Natural Petroleum Council, *U.S. Energy Outlook*, December 1972, page 91.

CONSTRAINTS AND OPTIONS TO DEVELOPMENT OF REQUIRED TECHNOLOGY

Natural gas is an important domestic source of energy and is the most environmentally clean fossil fuel available to serve our nation's energy needs. This study indicates significant future supply potential for natural gas to provide a larger contribution to the national energy mix. However, realization of this potential depends on continued advancement of technology related to gas supply. Natural gas will be available as projected by this study only if technology advancement continues to be successful at reducing costs and making new sources accessible. To assure this continued advancement of technology, investment in upstream R&D will be necessary.

Technology Advancement and Impact

The adequate supplies of natural gas projected by this study depend on continued progress in technological improvements. These improvements include not only the significant breakthroughs that change the way an industry conducts its business, but also the myriad of small improvements and the gradual adoption of these improvements by the majority of the industry participants. The industry can experience a quantum change in a particular technology with dramatic impacts on a portion of the resource base. However, when the overall results are examined, the improvements appear as continuous and gradual. All of these developments, both major leaps and continuous improvement, are required to maintain the overall rate of improvement that has been experienced in the past.

The domestic natural gas resource base and its cost-effective availability have been consistently underestimated. The methods used by government and industry of reporting reserves of natural gas as only *proved* led to the commonly reported number of only 10 years of supply remaining and enhanced the perception that the natural gas resource base was insufficient to support anything except declining future use. Many policies, including R&D priorities, were formulated based on this perception. A more fundamental understanding of the natural gas resource base shows that this is an inappropriate way to describe natural gas potential. Proved reserves represent only a "warehouse" inventory.

This inventory has remained basically constant relative to annual production for over 10 years, while the estimates of the resource base have continued to grow. New areas, such as beneath offshore deep waters, and new sources, such as tight gas sands, coalbed methane, and shale formations, have been added to the assessed resource base in the last 20 years. In addition, new knowledge of the existing reservoirs continues to provide greater recoveries.

While it is difficult to identify with certainty technologies that will be important in the future, it is reasonable to expect that innovations will be introduced just as they have been in the past. The impact of technology on the resource base is dramatically demonstrated by comparing the industry's estimate of the natural gas resource base in 1972, as reported in the 1972 NPC study, with the resource base in this NPC study. The 1972 study concluded that the "ultimate discoverable" natural gas resource base for the lower-48 states was 1,580 TCF, including 674 TCF of cumulative production and proved reserves. This number has now grown to 1,825 TCF, including 920 TCF of cumulative production and proved reserves as of 1992. This is a 0.7 percent per year compound growth rate for the "ultimate discoverable" resource base.

Technology advancement will continue to expand the gas resource potential and reduce the costs to develop these gas resources just as it has in the past if adequate investment in R&D is maintained. Failure to include continued technological advancement in gas supply projections will underestimate future supply *and* overestimate future required prices. This study includes estimates for the impact of future technology development and employment and describes a natural gas resource base of 1,295 TCF remaining resource base, assuming continued technology advancement during the next 20 years. Over half of this resource base was not in the industry resource considerations 20 years ago. Furthermore, there are numerous sources of gas that are not assessed in this study. These include things such as resources beneath deeper water, gas hydrates, and significant portions of the tight gas sands formations. Consequently, this estimate will likely grow after another 20 years of experience. There are indeed great potential natural gas resources in the United States.

Continued technology advancement and application is a key to obtaining these resources.

Issue

With the domestic industry shrinking, how can the necessary technology advancement be ensured and transferred throughout industry in the most cost-effective and efficient manner?

The technological advances by the industry have been accomplished because of a strong commitment to relatively stable, well-funded research programs. The larger companies in petroleum exploration and production have relied on internal research programs, and provided the bulk of these funds. There has been little support from the upstream sector of the industry for federal entry into petroleum exploration and production research. Industry has in general believed that private research spurred on by a healthy business environment and supportive government policy was the most efficient approach. The competitive nature of the industry and the large amount of research effort by various segments of the petroleum industry, including E&P companies and service companies, have been seen as adequate. This competitive, private-sector approach to the upstream side of the natural gas business has been very successful in providing today's advanced level of technology development and employment, which has continued to lower the cost of providing new resources of natural gas.

However, with revenues and profits of the petroleum companies and the service sector decreasing with reduced world oil prices and the low U.S. gas prices, the funding for this research is coming under increasing pressure and, consequently, is in doubt.

Industry R&D Funding

In order to identify the total R&D funding for the upstream segment of the industry, and how that funding had changed from 1988 to 1992, the NPC contracted with ICF Resources, Inc., of Fairfax, Virginia. ICF Resources surveyed the largest 25 companies with R&D facilities, believed to represent over 90 percent of the total upstream R&D funding by the industry, and obtained an estimate of the total upstream R&D and technical service funding for the industry. All responses were kept confidential, and only the aggregated data for operators and service companies were presented. (The full report is included in Appendix L.)

It is very difficult to segregate gas research funding from other research funding in the exploration and production segment of the industry. In the survey, only 13 percent of the funding by operators and 3 percent by service companies could be identified as specifically for gas R&D. However, there is a large segment that is related to both oil and gas, and it cannot be differentiated between the two products. Consequently, any analysis of upstream R&D funding must include all upstream R&D funding.

For the 1988–1992 period, the industry increased its commitment to *gas and oil* R&D from $1,218 million to $1,429 million, representing an increase of 17 percent in nominal dollars, and unchanged in real dollars. This increase was concentrated in the service companies—up from $333 million in 1988 to $472 million in 1992.

The operating companies' expenditures for R&D and technical services also increased, but only about 5 percent from $851 million in 1988 to $891 million in 1992. These expenditures are concentrated in a few companies. The three largest R&D budgets make up 53 percent of the 17 operating companies' total, and the top six companies make up 78 percent of the total.

The survey was designed to reflect expected expenditures after any restructuring programs that were underway at the time of the survey. Study participants verified that the submitted information was as current as possible. However, there was considerable concern that the companies simply had not had enough time to make specific decisions regarding R&D, and that significant reductions would be likely in the near future, especially with the major capital investment reductions occurring.

The Gas Research Institute, founded in 1976 and approved in 1978, also invests in upstream technology development. It has averaged investing about one-third of its budget in upstream projects, and expects to invest $66 million in 1992 out of a budget of $184 million. Both larger, but especially smaller companies have begun to rely on the Gas Research Institute for upstream technology development and support. These demands will likely continue to increase in the future.

Government DOE Fossil Energy Funding

Over the past 13 years, the budget for the Fossil Energy Office of the DOE has varied between $273 million and $1,119 million (see Table 10-1). The percentage of funds allocated to natural gas has varied between 2 and 6 percent of the total. Coal research has dominated the program quite consistently for more than a decade, consuming 85 or 90 percent of the fossil energy research funding. This is in part an artifact of the perception that natural gas was *not* an abundant domestic resource and coal was. By contrast, the DOE predicts gas to contribute more than 20 percent of the energy consumed in the year 2010, and now the NPC study indicates natural gas could make even larger contributions to the national energy mix.

Many industries in the United States rely on the federal government and/or a pooling of research funds for much of their R&D effort. Agriculture has been a major beneficiary of government sponsored research and development, and has achieved major technology development. The medical industry has the National Institutes of Health. The commercial aircraft industry has had help from the National Aeronautics and Space Administration (NASA) and the Defense Department.

NPC Proposal: More Federal Research for Natural Gas

Recognizing the new perception of an abundant natural gas resource base and the cost and environmental benefits of natural gas, the National Petroleum Council proposes that the federal government, through agencies with the DOE and the Department of Interior (DOI), expand its gas supply R&D effort to provide a more balanced distribution between coal and natural gas. Several reasons for this increase in government participation in natural gas research programs are documented in the following paragraphs.

New Understanding of the U.S. Resource Base

The natural gas resource base is now recognized as adequate to support a much larger share of U.S. energy demand than was previously believed possible. Coal is no longer the only abundant domestic fossil fuel. Government research programs should recognize this change in perception, setting policies and priorities that are consistent with the natural gas resource base, especially given its positive environmental characteristics.

New Openness to Joint and Shared Research

There is a growing recognition within the producing industry that a single company cannot capture exclusively all the benefits of its successful research. Some competitive advantage is lost quickly because of multiple ownership interests in common producing fields and the extensive use of a service industry. Service company technology improves and spreads quickly throughout the industry. The spread of new technology is also enhanced because there is intense interest by all segments of the industry in technology applications.

Potential for Significant Breakthroughs

Most gas has been discovered as a result of looking for oil. Focusing on gas is a relatively new activity, so research is still likely to produce important results. Numerous studies, including this NPC study, present important topics for further gas research, such as reservoir characterization. Furthermore, research on gas will help exploration and production of oil as we work with an increasingly mature domestic resource base.

Transfer of Technology Throughout Industry

Government can help facilitate the transfer of technology as well as help advance technology development. The full impact of a technological development can only be realized when it has been applied to all appropriate resources in the industry. To achieve this, the technology must be transferred to the members of the industry. One way the government, in cooperation with industry and established industry associations, can assist in this transfer of technology is through project and workshop sponsorship.

TABLE 10–1

DEPARTMENT OF ENERGY—OFFICE OF FOSSIL ENERGY ENERGY RESEARCH AND DEVELOPMENT EXPENDITURES

(Millions of Dollars)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Coal													
Control Tech & Coal Prep.	$38	$37	$22	$28	$26	$35	$33	$38	$42	$49	$58	$56	$51
Adv Res & Tech. Dev.	56	58	56	36	46	40	35	32	32	27	27	31	30
Coal Liquefaction	250	521	99	38	29	26	33	24	27	32	35	43	39
Combustion Systems	51	57	31	24	18	30	30	15	22	27	34	37	38
Fuel Cells	26	32	34	30	43	41	35	28	33	27	39	43	51
Heat Engines	50	36	15	5	6	12	13	12	18	23	21	24	18
Underground Coal Gasif.	10	10	8	6	6	6	4	2	3	1	1	1	0
Magnetohydrodynamics	75	67	22	29	30	31	29	26	35	37	41	40	40
Mining R&D	69	49	14										
Surface Coal Gasification	116	165	53	39	36	32	43	25	23	22	24	15	11
Clean Coal							99	149	199	190	554	391	465
Total Coal	**$741**	**$1,032**	**$354**	**$235**	**$240**	**$253**	**$354**	**$351**	**$434**	**$435**	**$834**	**$681**	**$743**
Oil													
Advanced Process Tech	6	4	4	5	5	5	6	4	3	4	4	10	14
Enhanced Oil Recovery	23	19	16	7	9	12	12	11	17	24	28	32	37
Oil Shale	28	33	19	12	16	15	13	11	10	11	9	17	6
Total Oil	**$57**	**$56**	**$39**	**$24**	**$30**	**$32**	**$31**	**$26**	**$30**	**$39**	**$41**	**$59**	**$57**
Total Gas	**$35**	**$31**	**$9**	**$14**	**$16**	**$10**	**$9**	**$8**	**$11**	**$11**	**$15**	**$16**	**$13**
Grand Total	**$833**	**$1,119**	**$402**	**$273**	**$286**	**$295**	**$394**	**$385**	**$475**	**$485**	**$890**	**$756**	**$813**
Percent Coal	89%	92%	88%	86%	84%	86%	90%	91%	91%	90%	94%	90%	91%
Percent Gas	4%	3%	2%	5%	6%	3%	2%	2%	2%	2%	2%	2%	2%

DOE and DOI Research is Changing

The DOE and DOI are working on new ways to sponsor cooperative research. The DOE wants companies to have a stronger role, through their own joint support, in the selection and conduct of the research. The U.S. Geological Survey, as well as other agencies within the DOI, also has a strong interest in cooperative, non-proprietary research on natural gas with a variety of organizations. These recent efforts have become more effective in guaranteeing relevancy by requiring industry participation and jointly funding projects with existing industry research consortia and organizations such as the Gas Research Institute.

Dialogue will continue between the government and the petroleum industry over regulation, access, and fiscal issues. Cooperative research will help establish ties and trust that can lead to solutions that are better for both parties and hence help ensure a stable future energy supply. Joint research is likely to be an improvement over government research conducted with little industry participation, and lead to better project selection.

Directions for Enhanced Research Program

The upstream natural gas industry can make the best use of federal research resources by the following approaches:

- Make cost effective, environmental compliance and reservoir characterization technology development a top priority.
- Focus and encourage joint industry participation in projects that are expected to improve productive capacity in the near or intermediate term.
- Continue to increase efforts to develop new ways to sponsor cooperative research projects with industry participants—with particular emphasis on achieving increased participation by independent producers.
- With industry participation, explore the support of longer term, more basic research, yet maintain a high degree of practicality.
- In cooperation with industry and established industry associations, pursue more aggressive technology transfer programs such as by sponsoring more DOE-funded projects and workshops.
- Allow companies, particularly smaller companies, to participate through in-kind contributions that are defined as acceptable under federal procurement rules and regulations.
- Continue to support ongoing research, such as that undertaken by the Gas Research Institute.

CHAPTER ELEVEN

THE IMPACT OF TAXES AND OTHER FISCAL MEASURES ON U.S. NATURAL GAS PRODUCTION

Taxes and other government imposts are important factors in shaping the economics of natural gas exploration, development, and production. While resource costs and realized prices are the prime determinants of natural gas supply economics, fiscal systems can be used to both increase and decrease the economic cost of supplying natural gas to the U.S. market.

Natural gas suppliers in the United States can face an array of taxes and other levies, three of which are most relevant to this study:

- Income taxes (federal and some states)
- Severance and production taxes (primarily at the state level)
- Lease acquisition bonuses and production royalties paid on federal and state mineral properties.

INCOME TAX TREATMENT

The federal income tax is of most relevance to gas producers; some gas-producing states also levy income taxes, and these taxes are typically based on federal taxable income (or some subset thereof). This discussion will be framed in terms of a corporation operating in the natural gas business: virtually all of the tax issues discussed will apply similarly to individuals and partnerships.

In general, a U.S.-type income tax system places a heavy tax burden on savings and capital formation. Savings are effectively taxed twice: once when the income providing the savings is taxed, and again when the income from the savings (interest, dividends, and capital gains) is subsequently taxed. An additional layer of taxes is imposed when the capital formation process is embodied in corporate entities.

Historically, a variety of devices have been employed to try and redress this bias in the regular income tax against savings and investment, on the presumption that savings and capital formation are vital to our advanced, capital-intensive industrial economy. These tax devices have included provisions such as investment tax credits, accelerated depreciation write-offs, lowered tax rates on capital gains, and dividend exemptions. While these provisions did help to neutralize the tax bias against savings and investment, they were frequently criticized by so-called "tax reformers" as loopholes.

The Tax Reform Act of 1986 introduced two mechanisms that reversed this trend towards neutralizing the tax burden on capital. First, nominal regular tax rates were cut, but the resulting revenue losses were offset by raising effective tax burdens on productive capital investment, via repeal of the investment tax credit and by extending cost recovery periods for many types of invested capital. Secondly, the minimum tax was reformulated as the alternative minimum tax (AMT) and expanded to the point where it became the de facto corporate income tax for many capital-intensive firms. A full discussion of the federal income tax treatment of natural gas producers must address both the regular income tax and the AMT.

The economics of natural gas production were not (on the whole) improved by the 1986 Tax Reform Act. While many tax experts recognize the negative thrust of these measures on U.S. economic growth and competitiveness, federal budget pressures have to date effectively closed off opportunities to remedy the adverse provisions of the Act.

A constructive natural gas policy for the United States should incorporate a fiscal component that minimizes disincentives to finding new gas sources, developing new gas technologies, and fully exploiting known gas resources. Two of the issues that will be discussed in this paper are the Section 29 tax credits for nonconventional fuels and the AMT.

SECTION 29 TAX CREDITS

Under Section 29 of the Internal Revenue Code, income tax credits are available to producers of "nonconventional" fuels. These fuels are defined to include gas produced from geopressured brine, Devonian shale, coal seams, tight formations, biomass, and synthetic gas fuels produced from coal. To be eligible for the credit, gas from the above sources (except biomass and synthetic gas) must come from wells drilled before January 1, 1993 and must be produced before January 1, 2003.

This credit was originally set at 53 cents per thousand cubic feet (MCF) and remains at that level for tight formation gas. The credit amount for the other categories of gas is escalated for inflation since 1979 and currently runs around 90 cents per MCF. The credit begins to phase out at the rate of 1 cent of credit lost for every 2 cents of gas price increase at gas prices above roughly $7 per MCF.

In recent years, the Section 29 credits have provided a valuable incentive in putting production of some of these important gas resources on a commercial basis. It is almost certain, for example, that the successful development of coal seam degasification technology over the past decade would not have taken place without the incentive credit. As the real wellhead price of natural gas has been declining since 1983, progress on development of other nonconventional gas technologies might also have ground to a halt in recent years without the incentives offered by Section 29. Technology development will provide the tools for continuing economic development of the nation's large resources of nonconventional gas.

The Section 29 credits have also been the targets of criticism, with some of it coming from within the natural gas producing industry. Key points of contention include: (1) the relative "fairness" of generous credits for these limited categories of gas when conventional gas producers face continuing price declines; (2) in the same vein, the timeliness of the credits when the gas market is faced with excess supply conditions; and (3) the inability of producers who are in an AMT position to make use of the credit.

Section 29 proponents point out in regard to the "fairness" issue that there are no barriers to entering the nonconventional gas producing business: the credits are going (as Congress intended) to those producers who took the risks and invested the capital in these new and largely unproved technologies. While it would have been useful to have these credits ten years sooner, when the United States was facing a short-term gas shortage and expecting Congress to time tax incentives for new technical developments to fit in conveniently with market conditions, it is—in any practical sense—asking too much. Finally, the Section 29 credits are by no means the only provisions of our tax code that have been effectively nullified by the alternative minimum tax: the problem lies with the AMT, and not with Section 29.

THE ALTERNATIVE MINIMUM TAX

The alternative minimum tax is imposed at a 20 percent rate (24 percent for non-corporate taxpayers) on a broader income base than that used for regular income tax, and the taxpayer pays the higher of the two taxes. Calculation of the AMT income base is complex and involves (among other things) adding several so-called "items of tax preference" back into the tax base. Many of these "preferences" are related to capital investment; for example, the excess of accelerated depreciation over much slower, economic life depreciation. As a result, the AMT has become a major tax concern not only of oil and gas producers but of many capital-intensive industries, especially during periods of depressed earnings. The AMT can also be a problem during the early, high-growth years of a new firm that is reinvesting most of its cash flow in expansion investments.

AMT payments may be carried forward and credited dollar-for-dollar against future regular taxes. Thus, the AMT may not be a major problem for taxpayers that are only sporadically in a net AMT position. But the credit is of little value to those taxpayers who find themselves in a more or less permanent minimum tax position.

With respect to investments in natural gas production, the AMT contains two preferences that expand the tax base by adding back portions of capital cost recovery incentives for depletion and intangible drilling costs (IDC). The depletion "preference" requires a corporation eligible for percentage, or "statutory," depletion to increase its AMT base by the excess of such depletion over cost basis. The IDC "preference" requires a corporation to increase its AMT base by "excess" IDCs (defined as the IDC expensed in the current year minus the deduction arising from 120 month amortization of such IDC reduced by 65 percent of a taxpayer's net income from oil, gas, and geothermal properties).

With few exceptions among major integrated producers, these "preferences" have been only marginal components of the AMT base. Distinct from these "preferences" are more devastating AMT "adjustments" for depreciation on tangible equipment and the so-called ACE adjustment (for "adjusted current earnings"). The ACE adjustment has several subcomponents, two of which are primarily responsible for the substantial AMT disincentive for domestic investment in natural gas exploration and production:

- The depreciation subcomponent—a further negative modification of capital cost recovery for tangible equipment
- The IDC subcomponent—a substantial detriment for which, unlike the IDC "preference," no offset for any net income from oil, gas, or geothermal operations is provided.

To illustrate the impact of these adjustments on capital deployed in domestic natural gas operations in the 1990s, lease and well equipment may be depreciated under the "regular" tax system using a seven year useful life and the 200 percent declining balance method. The AMT depreciation adjustment and the ACE subcomponent for depreciation result in the effective use of a 14-year useful life and the 120 percent declining balance method. The ACE adjustment also contains a subcomponent for IDC, which is calculated using 60-month ratable amortization; by contrast, for "regular" tax purposes an integrated producer may recover 70 percent of IDC in the year incurred with only the remaining 30 percent amortized ratably over 60 months, and an independent producer may recover 100 percent of IDC in the year incurred. Tax revisions in 1990 provided for an "Alternative Tax Energy Preference Deduction" for independent producers, which is equal to:

- 75 percent of that portion of the IDC "preference" and the IDC sub-component of the ACE adjustment which is attributable to "qualified exploratory costs"
- 15 percent of the remainder of such IDC elements of the AMT base.

This special deduction from the AMT base is not available to integrated oil and gas companies.

The AMT unfairly penalizes compliance with environmental requirements. This growing body of government regulations necessitates significant new capital expenditures for environmental equipment by many industries, including natural gas. The value of tax deductions for depreciation or amortization of these non-earning assets is reduced by the AMT. The AMT negatively impacts on a taxpayer's efforts to be a responsible corporate citizen by taxing environmental expenditures that produce no taxable economic income.

In the depressed price environment that has prevailed in recent years, many natural gas producers who are in a loss position with regard to the regular income tax have found themselves faced with substantial AMT liabilities because they have remained active in the natural gas business. For example, to the extent that the most obvious strategy for reducing AMT exposure for many operators is to cut back on IDC outlays, the AMT has, in effect, become a penalty tax on drilling gas wells. Many industry observers feel that this perverse outcome is inconsistent with U.S. energy policy goals and is not what the framers of the AMT intended, and that natural gas and oil related incentives should not have been included as AMT "preferences."

STATE PRODUCTION TAXES

A number of states impose income taxes on natural gas producers. Most producing states also impose severance, production, or *ad valorem* taxes on gas production, typically assessed at 4 to 6 percent of gross production value.

In a competitive gas market, taxes imposed on gross production value become a fixed cost per unit of gas production to the gas producer. This tax "wedge" will reduce the marginal profitability of a well and move up in time the decision to abandon the well as uneconomic, thereby leaving some potentially economic gas in the ground.

States are unequal in geologic potential for natural gas and in their distance from markets. Low production tax rates are positive incentive factors that help sustain exploration activity even in areas where geology is poor or prospects are marginal.

An example of a state that provides consistent, favorable production tax policies to support its moderate geologic prospects is Utah. Utah's severance tax percentages are in the middle to low end of the range. Its tax policy and incentives for prolonged production life are commendable; it provides a severance tax exemption for stripper wells producing 60 MCF per day or less. Despite the favorable tax environment, Utah is burdened by subsurface geology that consistently reflects the highest per-foot drilling costs in the region. The maintenance of a significant level of exploration and production in Utah is supported by this prudent production tax policy. Utah also provides a twelve-month severance tax exemption for wildcat wells and a six-month exemption for infield development wells. On other gas production, Utah changed from a straight 4 percent severance tax to a 3 percent tax for gas sold at $1.50 per MCF and below, and 5 percent for gas sold for $1.51 and above.

Arguments for states to establish flexible production tax policies include the fact that they compete with other countries as well as other states for markets for their resources, and that a heavy burden of production taxes will lead to lower drilling activity and production, employment, and income tax collections. Taxation policies that provide for exemption for stripper and wildcat wells and a sliding scale of tax relative to wellhead price, will help keep the drilling industry viable even in periods of low prices.

Arguments against reducing severance taxes are that states are under pressure to raise, not lower, revenues during economic downturns, and that there may be no politically viable alternative source of revenue.

OTHER FISCAL BURDENS ON U.S. GAS PRODUCERS

From 1954 through 1989, most wellhead natural gas prices were subject to federal price controls that in many instances kept wellhead realizations well below the competitive, free-market price of natural gas in the relevant markets. Price ceilings were essentially equivalent to 100 percent excise taxes between the controlled price and the free-market price of natural gas, except that the tax "revenues" accrued to transporters, resellers, and users of natural gas instead of the government. With the low wellhead prices prevailing in recent years, many of these price controls became irrelevant, and most of them were removed in 1989. The few that remain are being phased out by 1993.

Natural gas producers typically do not own the rights to the underground minerals on the properties where they operate: they lease them. In the United States, federal or state governments own the mineral rights to virtually all offshore continental shelf acreage as well as to onshore public lands. In areas where there is thought to be significant potential gas or oil, lease rights for a fixed term are sold to the bidder offering the highest up-front cash payment or "bonus" at a sealed-bid auction. During the 1980s, the U.S. government received nearly $28 billion in offshore lease bonus payments from the gas and oil industry.

In addition to bonuses or other considerations paid to obtain a lease, the gas producer is usually obligated to give the mineral owner a royalty, that is, a specific share of the gross production from the property free and clear of any production costs. The royalty may be delivered in the form of actual gas, or the producer may sell the royalty share and remit the gross proceeds in cash to the royalty owner.

In many countries, all mineral rights are state property and the government receives all royalties. In the United States (plus Canada and a few other countries), there is extensive private ownership of mineral rights, but both federal and state governments are large owners of mineral rights and receive sizable revenues from oil and gas production. Royalty rates vary, but a one-eighth royalty is fairly typical in the United States.

When world oil prices fell in 1986, a number of foreign countries moved quickly to modify their fiscal regimes for gas and oil exploration and development in order to encourage continued private company activity. There is clear evidence that the post-1986 drop-off in drilling activity in those countries that adopted positive incentives was (typically) significantly less than in countries like the United States, which offered no fiscal relief measures to the gas and oil producing industry. Some of the provisions adopted by foreign governments are of little interest because the specific fiscal mechanisms employed are not readily adaptable to a U.S. setting. However, some of the ideas could be applied to the situation in this country.

Providing for immediate write-offs of intangible drilling costs and exploration and development outlays (except lease bonuses) would significantly lower the after-tax capital costs of natural gas development. Unfortunately, the politics of adopting such a program in the United States are probably poor. Similar arguments hold for expensing almost all investments in productive assets, but the adverse short-run revenue impact on the government is a formidable obstacle.

The federal government currently receives about $2 billion a year in royalties from offshore gas and oil production on federal lands. Measures to reduce or temporarily suspend royalties, particularly for marginally economic fields, can help to spur additional activity, bring on additional supplies at an earlier date, and extend the life of declining fields. Such proposals would be particularly significant if applied to existing leases on public lands: the effects of offering more lenient royalty terms on new leases would be offset in part by resulting increases in lease bonus bids. If carefully targeted to fields that would not have been developed (at all or until much later), such royalty rate reduction or suspension can result in no loss or even an increase in revenues to the government. There have been some proposals in Congress to reduce royalties, but no action has been taken.

CONCLUDING NOTE

Arguments for broadening fiscal incentives for U.S. natural gas (and oil) include the benefits of reducing dependence on foreign oil and improving the balance of trade; the maintenance of a strong domestic oil and gas industry, along with its contribution to employment and national economic activity; and reductions in production costs and prices of natural gas. Typical arguments against broadening fiscal incentives are that such action could reduce near-term tax revenues; such action is either politically difficult or, if politically acceptable, incentives may discriminate among producers; and if achieved, the incentives may add to the current gas surplus.

In a world with large public budgets and continuous pressures to raise more tax revenues, it is unlikely that any fiscal package for natural gas development will please all parties to the political debate. Improvements in the economic environment for the U.S. natural gas producing industry hinge far more on future wellhead prices than on producer tax incentives. However, it is also important to maintain a fiscal setting that does not hamper worthwhile efforts to expand domestic natural gas supplies.

CHAPTER TWELVE

ENVIRONMENTAL CHALLENGES AND OPPORTUNITIES

As part of an overall effort to understand the impact of environmental issues on the use of natural gas in the United States, the Environmental Regulations Subgroup examined the effects of environmental legislation, regulation, policy, programs, and access restrictions on the exploration, development, and production of natural gas. Based upon this evaluation, the Subgroup developed a series of recommendations for the Secretary of Energy, as well as for industry, that could help expand the role of natural gas in the national energy strategy.

Since natural gas has intrinsic environmental benefits as a clean-burning fuel, the Subgroup began with the premise that there is a set of "constraints" that prevent or inhibit the full utilization of natural gas in the national energy strategy. These "constraints" exist both external to the industry (i.e., legislative, regulatory, etc.) as well as internal to the industry (cultural, policy, practices, etc.). The methodology employed was a facilitated brainstorming process, drawing on the combined expertise of the industry and government members of the Environmental Regulations Subgroup, as well as key representatives from other interested members of the NPC natural gas study. The process produced the following observations regarding the environmental "constraints" facing the industry along with a corresponding series of "options" (i.e., recommendations) available to government and industry to overcome these "constraints."

It is important to point out that the constraints identified include national, regional, and local factors that inhibit natural gas supply. The recommendations for national issues apply uniformly across the industry and the country. Recommendations for potential solutions to local or regional problems are not intended to automatically apply, or more importantly, may not always be appropriate for all situations or for all parts of the country. Part of the implementation process for the recommendations is a critical analysis of the local or regional situation before developing a specific strategic action plan.

WHY ENVIRONMENTAL CONSTRAINTS EXIST

A number of problems exist that constrain the full utilization of natural gas. These problems include less than optimum government policies, processes, and practices (legislative, regulatory, and administrative); misperceptions and misunderstandings about the natural gas industry and its practices by government and the public at large; superior strategy by environmental groups; and the lack of a coordinated and cohesive industry process to understand and meet the environmental needs and expectations of the public.

Government Policies, Processes, and Practices

Legislative and regulatory processes, because they are often confrontational and procedurally committed to hearing every concern and giving people every opportunity to be involved in the process, are very slow and costly to industry and thus favor the environmental activists who want to delay or stop any action to increase production. Decisions are revisited and overturned, injunctions are upheld, and moratoria are introduced—all with severe cost impacts on natural gas production. On the downstream side, traditional economic regulation has often put natural gas at a disadvantage. The Federal Energy Regulatory Commission (FERC) and state commissions are not attuned to the environmental benefits of natural gas and are, at best, fuel neutral. There are no user incentives for increased natural gas use and government is not demonstrating the leadership necessary in these areas.

The impacts of the regulatory processes are not fully appreciated by regulators, legislators, or the general public. There is inadequate consideration of the cumulative impact of conflicting regulations and various regulatory bodies, and energy policy is inconsistent among the various elements of government.

Government and Public Misperceptions

Inaccurate perceptions of natural gas create barriers to increased production. Natural gas production is associated with highly publicized environmental problems such as crude oil spills. More generally, there is a public perception that what is "good for industry" is "bad for the environment" and there is only a limited united industry effort to counteract these perceptions. Little is known about the environmental benefits of natural gas nor its benefits to the economy in producing jobs, tax revenues, and energy security. The result is legislative and regulatory actions adverse to increased natural gas production. While there is a growing sentiment toward natural gas as the fuel of choice, this sentiment is not reflected by the myriad of impediments imposed by legislators, regulators, and the environmental community.

The public, including many of its government institutions, has a general mistrust of business and particularly the oil business. The natural gas exploration and production industry and the oil industry are seen as one. Underlying this lack of trust is a basic feeling that industry does not have the same values and respect for the environment as the public. The impact of this lack of trust is significant. Any industry information on environmental matters is suspect, and this has driven legislators and regulators to micro-manage the process. Even more serious, some government agencies, particularly in the producing states, are seen as too close to industry and are also suspect as sources of credible information.

Environmental Groups

Environmental organizations have historically had an advantage in public policy debates because their strategy centers on tapping the emotional nature of the issues and building their public and government support around that emotion. They are experienced and have framed the controversy as environmental and social values pitted against industry's economic self-interest. They in effect have better developed political strategies. In this context, industry can never do enough environmentally. Environmental groups have become institutionalized with well-funded programs and experienced, well-paid, professional staffs that work full time to sustain the environmental movement. Compromise can be seen by these environmental institutions as a weakness for fund raising and for continuing their environmental programs.

The general public is also demanding more environmental responsibility from companies, and these demands will continue to grow. At the same time, the public has little concept of the trade-offs involved in their energy choice; they have a desire for zero risk at minimum cost, even when these are potentially in conflict with one another and with their environmental desires. There is no linkage between the desire for more natural gas use for environmental purposes and the required increase in exploration and production that can make it happen.

Industry

Industry leaders often have business or technical backgrounds rather than political and public policy backgrounds. They take a traditional business approach in their decision making, which often does not fully take into account the needs and expectations of the public and government. Like most large institutions, the companies making up the natural gas industry are often slow to adapt to a rapidly changing political environment. Many companies are often unwilling to be the first to adjust to a new environmental standard for fear of setting precedents or losing their competitiveness.

Many in the domestic industry are increasingly unwilling or unable to spend the seemingly unlimited time and money necessary to overcome permitting and access problems. Driven by the current economic climate and declining potential for finding oil, many in the industry have all but given up on additional investment in domestic oil and gas production.

In addition, the industry has traditionally not pursued opportunities to build coalitions with groups with common interests, and therefore has lacked broad support for its issues.

SUMMARY OF CONSTRAINTS

In summary, the environmental legislative and regulatory decision-making process in the United States, coupled with current industry culture, inhibits the full utilization of natural gas as an environmentally preferred fuel in the national energy mix. Specific constraints include:

- Legislation, regulation, and government policy do not adequately balance the direct upstream costs and benefits of regulations and do not include an analysis of the downstream benefits of natural gas.
- The environmental benefits of using natural gas are not well understood by the public and policy makers. The natural gas industry is seen more negatively than deserved and is perceived as not being credible and is not trusted.
- Environmental interest groups operate with a high level of public trust and have been more successful in focusing their resources in an effective advocacy strategy.
- The natural gas industry has not been successful in fully aligning its goals with the public's needs and expectations.

The result has been an increasing economic burden from environmental regulations relative to benefits, drilling moratoria, lack of access for exploration, and the cancellation or deferral of government lease sales.

OPTIONS FOR OVERCOMING CONSTRAINTS

Clearly, there is a need to develop a revised industry advocacy/outreach program and modify government programs to create a more balanced regulatory process and educate the public on the net environmental benefits of natural gas. Several options or recommendations are proposed for overcoming the above constraints:

- Encourage government, at all levels, to create a balance between costs and benefits in the legislative and regulatory process for upstream environmental and access issues. This includes the direct recognition of the environmental benefits of natural gas as a clean-burning fuel.
- Develop and supply timely and credible technical cost-benefit data for use in communication efforts with government, environmental groups, and the public. Focus research activities toward developing more cost-effective solutions to the environmental challenges facing the industry.
- Enhance education programs to increase the public's understanding of the positive role natural gas can play in solving the nation's environmental problems. Target audiences include federal, state, and local governments, environmental organizations, and the general public.
- Develop new innovative industry strategies to better align industry's goals with the public's needs and expectations in order to create more timely and efficient solutions to environmental, permitting, and access issues (i.e., create win/win situations for industry, federal, state, and local governments, environmental groups, and the general public).

These options or recommendations are discussed in more detail below.

RECOMMENDATION 1

Encourage government, at all levels, to create a balance between costs and benefits in the legislative and regulatory process for upstream environmental and access issues. This includes the direct recognition of the environmental benefits of natural gas as a clean-burning fuel.

The current environmental legislative and regulatory process is governed by public policy, which is in turn driven by a growing public concern over the environment. The rapid urbanization and the continued industrialization of the country, coupled with perceived historical poor performance of both government and industry, has created a climate for over-regulation and limits on access that often exceed what would otherwise be dictated in a balanced, scientific evaluation of the issue. In most cases, the downstream benefit (i.e., the net environmental benefit) of natural gas is often not even included in the public policy debate on upstream environmental issues.

The situation that exists today varies by jurisdiction but includes forums where there are specific legal prohibitions against doing the analysis; situations where agencies don't have the time, money, or motivation to do the analysis; and situations where agencies do the analysis but don't do it accurately. The most current, and potentially costly, example for the domestic oil and gas industry is the lack of a balanced cost-benefit analysis, including the downstream benefits of natural gas, in the current legislative debate on Resource, Conservation and Recovery Act reauthorization.

The following three items have been identified as independent items to implement this recommendation. Within each action item a number of specific options for government and industry have been identified for accomplishing the goal. In several cases alternative options have been identified. Some of the alternatives are either/or options but in the case of local/regional issues the options are more of a family of potential solutions with the best solution a function of the local/regional situation. The following is a discussion of each action item and the range of implementation choices available.

Implementing Items

1. Extend (or reintroduce) the regulatory moratorium to review and modify the current regulatory and permitting process by:

- *Monitoring the effects of regulatory stability*
- *Developing accepted methodologies for developing cost-benefit information*
- *Researching the cost and benefits of current regulations*
- *Developing methodologies to bringing balance to permitting and access issues.*

A National Item for the Administration: This Item takes advantage of the momentum from the current regulatory moratorium to take a step back and look at the strengths and weaknesses of current regulations and the entire regulatory and permitting process. The extension of the moratorium would allow government and industry the opportunity to monitor the effects of regulatory stability and develop practical methods for overhauling the existing system. Politically it may be difficult for the President to continue to extend (or reintroduce) the moratorium, but since the current exploration and development activity is at or near all time lows (therefore minimum risk for government), it is a good time to undertake the analysis.

The disadvantages of this Item include consuming political capital with the White House, developing a credible mechanism for conducting the analysis that all stakeholders would support, and most importantly, once the mechanism has been developed, identifying and funding the resources necessary to do the work. The issue may be ripe, however, particularly if this initiative could be married with others designed to develop new forums for consensus building.

2. Modify the legislative and regulatory process to ensure that cost-benefit analyses are completed and the net environmental benefits of natural gas are included in the decision-making process.

This recommendation could be implemented via at least five different routes including statutorily requiring legislative and regulatory staffs to do the work, establishing a new administrative office of Cumulative Regulatory Impact in the Office of Management and Budget, the Council on Environmental Quality, the Department of Energy (DOE), etc., creating third party impartial centers for analysis, establishing inter- and intra-agency working groups, and in a more direct public route by utilizing negotiated rule making. Each has its pros and cons, and in actuality, different forums may dictate different approaches.

An Item for National, State, and Local Regulatory Agencies: The most practical approach would be the creation of an inter- and/or intra-agency working group/groups to monitor legislative and regulatory proposals that have a significant impact on the energy supply/demand picture. This is the simplest approach requiring no legislative action and the minimum incremental staffing. These analyses, done independent of the actual legislative/regulatory debate, would carry a greater degree of credibility with all stakeholders. The disadvantages of this approach are not trivial in that the working groups would have to compete for manpower and funding within each of their individual organizations and from existing budgets. In addition there are opportunities for inter-agency jurisdictional issues which could slow and/or interfere with the quality of work.

A National Item for the Administration: The most effective overall solution could well be establishing a new administrative office of Cumulative Regulatory Impact (i.e., a central organization to look at all impacts of environmental and energy regulations to identify synergies or lack of synergy including upstream and downstream benefits) in the Office of Management and Budget, the Council on Environmental Quality, the DOE, etc., to perform the analyses. The advantages of this approach include a clearly identified role and responsibility in the process including an independent budget. The independent nature of the analyses would carry an even greater degree of credibility with the stakeholders than inter-agency working groups. The disadvantage of the approach is the increased administrative and financial burden from creating a new self sufficient organization. The Council on Environmental Quality appears to be the best location for the office to maximize the utilization of existing technical expertise and minimize outside political influences.

An Item for National, State, and Local Government and Industry: The boldest approach, particularly for industry, is to broaden the use of negotiated rule making. In this approach, all parties involved carry the joint responsibility of ensuring balance in the decision-making process. This approach may not work in all situations because the participants must all have a vested interest in resolving the issue. If this situation doesn't exist, then one party can irrevocably stalemate the decision-making process. If the right conditions exist, then the major advantage of this approach is an agreement that is much less subject to litigation or further confrontation. The disadvantage is that the process can be slow and sometimes agonizing and not absolutely immune from forces outside the negotiation process. The best opportunities for success may lie in rule development rather than with local access issues, but in the right setting, and with innovative participation by all parties, it may also be extremely valuable for permitting. [Note: See Recommendation 4, Item 1, Example 2, for guidelines on structuring negotiated rule making.]

In addition to the three approaches above, there are two lesser options, both of which have their advantages.

A National Item for Industry and/or Government: The cost-benefit analysis work could be done via an independent third party institution set up specifically for the task. The advantages include maximum credibility with all stakeholders (most notably the public) and the creation of a center of excellence or career experts specializing in environmental issues affecting the energy industry. The major disadvantages of this approach are the additional administrative and financial burdens associated with the start-up and maintenance of a new, stand alone entity and the limited industry quality control on the finished products. This approach might become a leading candidate if issues, environmental or otherwise, dictate the need for a third party approach.

A National Item for Congress and/or the Administration: The last approach is just to require, either through legislation or administration policy, that cost-benefit and net environmental benefit analyses be done by legislative or regulatory bodies proposing environmental legislation or regulation. This sounds like the most reasonable approach, but these analyses are often self fulfilling prophecies (i.e., the analyses done directly by the governing body often reflect the initial bias of the author). [Note: This is not intended to be a criticism, it is a reality that applies to industry as well as government.]

3. Insert cost-benefit analysis into federal and state regulatory decision making in FERC and state public utility commissions.

An Item for Congress and State Legislatures: This is the downstream equivalent of Item 2 above. The advantages are that it creates an opportunity to level the playing field relative to other competing fuels and possibly overcome some of the regulatory and permitting barriers facing natural gas projects once the net environmental benefits are made explicit. It also would enhance government and industry education efforts on the advantages of natural gas relative to other fuels. In addition these proceedings are monitored by consumer advocates who have the potential for becoming allies once all the facts are known.

4. Modify federal leasing programs so that bids that are based on accepted environmental guidelines would come with drilling permits.

An Item for Congress and the Administration: This action item would literally require an act of Congress to implement. The advantage of this approach is the security that new lease purchasers would actually be able to drill once leases were awarded. The advantages are obvious in that much of the financial risk to lease holders from failed permitting attempts would be eliminated.

The disadvantages lie in the conditions that would have to be agreed upon before the lease sale could proceed. A generic set of conditions could be developed in what would be a very complicated rule making because of the need to develop a process to cover site specific local issues. This would be a time-consuming process with no guarantee that utilizing generic conditions would be any better than actual site-by-site regulations. If a site-specific process could be developed it would have the advantage of meeting local needs more directly and therefore more efficiently. The disadvantage is that the entire industry (or the subset of industry interested in bidding) would have to go through the process whether or not they ever successfully acquired a lease. This could be an extremely difficult and time-consuming process since there are often diverse strategies used by industry in approaching permitting.

5. Modify the OCS Lands Act to share some of the current federal revenue with local jurisdictions.

A National Item for Congress and the Administration: The onshore impacts of Outer Continental Shelf (OCS) oil and gas development are largely borne by the adjacent onshore areas that have the infrastructure of port facilities, pipeline landfalls, processing facilities, and associated support industries. Local tax revenues generated by the offshore support industry may not be sufficient to pay for the roads, schools, and other government services the industry consumes. Under this action item, a portion of OCS revenues would be returned to local coastal governments as a form of impact assistance. These funds would benefit those local areas most affected by OCS activities and help offset potential burdens on local communities. It is important that any such proposal provide a direct link between the amount of OCS activity and the amount of assistance payments provided to nearby state and local governments.

A proposal for coastal impact assistance has been developed by the Minerals Management Service and proposed by the Administration as an amendment to the OCS Lands Act. The advantages include providing a portion of the government revenue generated by OCS activity directly to states and local governments located near offshore activities, as well as reducing some of the entry barriers the industry faces from financially strapped state and local governments. The major disadvantage is that it would require legislative action and would reduce federal revenues.

RECOMMENDATION 2

Develop and supply timely and credible technical cost-benefit data for use in communication efforts with government, environmental groups, and the public. Focus research activities toward developing more cost-effective solutions to the environmental challenges facing the industry.

Under the existing command and control legislative and regulatory process, it has been the role of government to develop not only the need for environmental controls, but in many cases determine or specify what "best available control technology" actually is. The result has been a confrontational process that results in, at best, a negotiated compromise that is politically driven, inefficient, and more often than not, excessive.

Industry has historically believed that it is government's role to determine the need for environmental legislation or regulation and develop technical data for comprehensive cost-benefit analyses. As a result, industry's participation has been more as a reactive critic rather than as a contributor or collaborator. As government budgets tighten and the complexity of environmental issues increase, it is becoming more and more difficult for legislative or regulatory staffs to develop adequate cost-benefit analyses. They simply don't have the human and financial resources nor an adequate knowledge of industry to do the job with the level of accuracy necessary. This is not a criticism but a fact. It is no longer an issue of who has the legal responsibility to ensure that creditable analyses are done. The issue is how to get the necessary work done to ensure that informed decisions are made and natural gas becomes an integral part the nation's energy mix.

In determining the level of control or the type of environmental controls necessary, industry has again historically deferred to government to identify "best available control technology." In fact, industry has often taken safe harbor in arguing that proposed controls are not currently demonstrated technology. The result has been the delegation of technology, and therefore the level of control, to either an inexperienced regulator, a consultant, an environmental group, or some third-party entrepreneur, none of whom understand industry's constraints or have a vested interest in the profitability of the industry.

The following are a series of action items designed to increase industry's involvement in the environmental problem-solving process on issues that impact the natural gas industry. Within each item, a range of alternative approaches has been identified for accomplishing the goal.

Implementing Items

1. Initiate a joint Industry/Government sponsored project to develop a methodology for doing cost-benefit evaluations and document in a "How To" manual for industry and government use. Participants in the project should be drawn from industry, government, and the environmental community.

A National Item for Industry and Government: This action item will produce a tangible work product with state-of-the-art methodologies and information that can be completed quickly and made available to both industry and government. The manual would also be flexible enough for national, regional, and local efforts. The limitations of this action item are that analyses done using the manual would not be done by just career experts but often by one-time users without the benefit of any cumulative knowledge, experience, or data. The manual would also have to be updated periodically as technology advances and the methodology ages in order to ensure that the results continue to be accurate and useful. The biggest disadvantage may lie in the lack of public credibility if used unilaterally by industry in the direct context of a rule-making or permitting event.

One of the work products from this effort would be a specific recommendation on how to best deploy the use of this methodology (i.e., what forums, what implementing organizations, etc.) [Note: This item has merit even if the following action items are not implemented.]

2. Based upon the output from Recommendation 2, Item 1, enhance the natural gas industry's capability to develop credible and timely cost-benefit data on both upstream (exploration and production), transmission (pipeline), and downstream (consumer/user) environmental issues. These analyses would address not only the absolute cost-benefit of the specific issue (i.e., the direct costs versus environmental benefits), but would also include the net environmental benefit of the use of natural gas relative to other fuels.

This recommendation could be implemented in a simple manner by just encouraging each company, trade association, and government agency to use the methodology. A more aggressive approach would be to create a broad natural gas industry consortium, a research institute, a university center of excellence, or a third party independent center. This could be a new entity or an expanded role for an existing organization (i.e., Natural Gas Supply Association, American Gas Association, Gas Research Institute, National Petroleum Council, etc.).

An Item for National, State, and Local Government and Industry: The simplest and least expensive approach is to encourage each company and government agency to use the material as the opportunity presents itself. The limitations of this approach are that the analyses done using the manual would not be done by career experts but often by one time users without the benefit of any cumulative knowledge, experience, or data. The methodology will age over time as technology and science advances, so if the material in the "manual" is not periodically updated then it becomes unusable or the results become less accurate. The biggest disadvantage may lie in the lack of public credibility of a unilateral industry analysis completed in the direct context of a rulemaking or permitting event.

A National Item for Industry: The most effective approach would be the creation of a stand-alone industry-wide natural gas industry entity with a clearly defined mission. The choices include an industry coalition, research institute, a university center of excellence, or a third-party organization. This could be a new entity or an expanded role for an existing organization (i.e., the Natural Gas Council, Natural Gas Supply Association, American Gas Association, Gas Research Institute, National Petroleum Council, etc.). The goal is to create an organization with the expertise and mission to develop and maintain a central body of information and expertise on the costs and benefits of environmental legislation as well as regulation and access issues that affect the supply and utilization of natural gas.

The up-front costs are greatest for this approach, but the long-term benefits of a quick and united response capability may more than offset any up-front costs by facilitating timely, united, and more effective industry responses during the legislative and regulatory process. This may become an even more attractive approach if there are driving forces from other areas to form a new stand-alone organization. The choice of whether this should be an industry owned and operated activity versus some type of a more hands-off approach is a choice between the degree of industry control (quality, timeliness, and content) and the public credibility of the information produced. The various approaches have a number of advantages and disadvantages in common. The big advantages are a centralized resource with readily available data and a body of knowledgeable experts ready to go to work on a specific issue, both of which supplement industry's resources available to do the work. The disadvantages are the costs and administrative burdens associated with developing and maintaining a new stand-alone organization. The best solution may be in an expanded role for an organization like the Natural Gas Council or an industry research institute, if it can be positioned to be as credible as the Electric Power Research Institute.

A National, State, and Local Item for Industry: The most practical approach would be to tap and expand the resources in existing organizations. This approach would minimize the time and resources necessary to get the effort started, but it would require a significant coordination and communication effort among multiple industry segments (each with historically different goals, objectives, and paradigms) to ensure that the total body of information needed to develop both the upstream and downstream costs and benefits was developed on time. This approach may actually be a trade between up-front organizational costs versus slower future response times to do the work because of the larger coordination effort required to gather all the necessary information.

3. *Refocus industry and government environmental R&D efforts on Pollution Prevention to develop more innovative and cost-effective environmental solutions.*

The options available to implement this action item include: refocusing existing environmental R&D efforts by individual companies, trade groups, and research organizations; increasing and/or redirecting government and government/industry co-funded research (via DOE, DOI, EPA, etc.); and forming a new cross-industry natural gas industry consortium to perform environmental research. None of these proposals are mutually exclusive.

A National, State, and Local Item for Industry: The first option is to refocus existing environmental R&D efforts by individual companies, trade groups, and research organizations. Traditionally individual company research efforts have focused on basic process improvements and have only more recently begun to evaluate and/or develop environmental control technology driven by proposed regulatory agendas. Industry sponsored "research" through existing trade associations has focused mainly on supporting advocacy positions. Neither the individual companies, trade associations, or industry research organizations have developed a major commitment to a solution-oriented or problem-solving environmental research agenda.

The goal of this action item is to inject industry into a more active role in developing tomorrow's environmental solutions by refocusing existing organizations and their research budgets to develop more innovative and cost-effective solutions. The most logical approach to accomplishing this objective is via the emerging concept of Pollution Prevention/Total Quality Environmental Management. Pollution Prevention/Total Quality Environmental Management takes quality management principles and directs them at traditional process improvement research but with a focus on solving environmental problems at the source.

The advantage of this approach is its simplicity and cost-effectiveness. It utilizes existing resources, organizations, and money and is consistent with emerging environmental public policy. The disadvantage lies in overcoming existing paradigms and thinking within industry and government. The goal is to begin moving away from a "defensive" posture and to begin to take the "offensive." The task of making the transition is even more difficult when current resources are completely consumed in the current "defensive" posture and when total industry research expenditures are shrinking. But the reward is more cost-effective solutions and, more importantly, regaining control of the decision-making process.

A National Item for Government and Industry: Increase and/or redirect government and government/industry co-funded research (via DOE, DOI, EPA, etc.) to stress Pollution Prevention/Total Quality Environmental Management to develop more innovative environmental solutions. This is the government equivalent of Option A. The same principles, advantages and disadvantages apply. One additional advantage from a national perspective is that advancements developed through these efforts are not proprietary and can more readily be used by the industry at large. The biggest opportunities may lie in the co-funded area because the paradigms are not as strong and government, particularly the DOE and EPA, has been very active in developing more productive joint research in this area.

A National Item for Industry: Form a natural gas industry consortium to perform environmental research in the Pollution Prevention/Total Quality Environmental Management area to develop more innovative environmental solutions. This recommendation may be the most effective or efficient in accomplishing the fundamental goals and objectives in the most timely manner, but it is also potentially the most expensive. This approach minimizes much of the paradigm-breaking time and energy that would be required in an existing organization, but it also carries the additional administrative burden required to support a new organization. The administrative burden could be minimized if other issues dictated the creation of a cross-industry consortium and if the additional costs for research could be partially offset by redirecting funding from existing organizations. In fact, the approach to funding could vary widely from the traditional dues approach, to project-by-project funding, to some type of a taxing mechanism.

RECOMMENDATION 3

Enhance education programs to increase the public's understanding of the positive role natural gas can play in solving the nation's environmental problems. Target audiences include federal, state, and local governments, environmental organizations, and the general public.

The public view of the role of natural gas in the national energy mix is currently clouded by a number of misconceptions about the safety and environmental benefits of natural gas.

Public Misconceptions: The public misconceptions about natural gas vary regionally depending upon how widely gas is currently being used and how aggressive negative advertisements are for competing fuels. In areas like the west, where gas is a "natural" part of everyday life, safety is not an issue and the existing paradigm gladly accepts the role of gas as an intrinsically clean, efficient, convenient, and safe energy source. In the east, where gas is less prevalent and the existing paradigm includes a much higher reliance on electricity, oil, and coal, the public's comfort level with the use of natural gas is much lower. The problem is often exacerbated by negative advertising by competing fuels.

The environmental benefits of natural gas are not very well understood by the general public. In the west, natural gas is marketed widely as a "clean" fuel, but the public's perception is more from a house-keeping point of view rather than as an environmentally superior fuel. The general public hasn't made the environmental connection yet. In the east, where natural gas is less familiar, the problem is even more severe. In the last five to ten years, government and the natural gas industry have not aggressively developed the potential natural partnerships and/or coalitions with consumer and environmental interests groups to take maximum advantage of the environmental benefits of natural gas.

Public Credibility: The oil and natural gas industry contributes to its image problem by its general behavior. It is a predominately inward-focused industry that traditionally makes decisions from the perspective of scientists and engineers rather than looking more outwardly and factoring in the goals, needs, and expectations of an ever-changing public. This behavior is often viewed by the public as arrogant. This perceived arrogance coupled with periodic events such as spills and releases has resulted in the industry's poor public image. The solution is not to make decisions just because it is what the public wants at the time, but rather to factor the public's varying needs into the decision-making process in an effort to merge industry's needs with the public's needs and create win-win situations.

Implementing Items

1. *Initiate a joint Industry/Government project to develop methodologies and tools for developing education and communication efforts to market the role of natural gas in a balanced but comprehensive energy conservation, pollution prevention/continuous environmental improvement, and energy development program. The project team should include representation from all potential target audiences and/or rely heavily on "client feedback." The methodology would be documented in a "How To" manual and/or training for industry and government use.*

A National Item for Industry and Government: This action item will produce a tangible work product with state-of-the-art methodologies and information that could be completed quickly and made available to both industry and government. The manual would also be flexible enough for national, regional, and local efforts. The disadvantages of this approach are that the analyses done using the manual would not be done by career experts but often by one-time users without the benefit of any cumulative knowledge, experience, or data. The methodology will require periodic updating as public issues, policy, and goals change. [Note: This item has merit even if the following items are not implemented.]

2. *Based upon the output from Item 1 above, develop an education and communication effort to market the role of natural gas in a balanced but comprehensive energy conservation, pollution prevention/continuous environmental improvement, and energy development program.*

This action item could be implemented through at least three different vehicles. The first vehicle would be to simply encourage each company and government organization to individually use the methodology. A second approach would be to create a new cross-industry natural gas consortium or a modified existing trade group to develop and implement a coordinated effort with government, environmental groups and the public. A third and more paradigm-breaking approach would be to actually include government, environmental groups, and the public as full members of the consortium commissioned to do the work.

An Item for National, State, and Local Government and Industry: The simplest and least expensive approach is to simply let each company and government agency use the material in their own independent advocacy efforts. This is the least-cost approach and it has the additional advantage of producing a tangible work product with state-of-the-art methodologies and information that could be completed quickly and made available to both industry and government. The manual would also be flexible enough for national, regional, or local efforts. The disadvantages of this approach are that the analyses done using the manual would not be done by career experts but often by one-time users without the benefit of any cumulative knowledge, experience, or data. Without periodic updates, the methodology will also age over time and become less useful or, worse, become counterproductive as public goals change.

A National, State, and Local Item for Industry: A cross-industry approach may be the most practical because it leaves the effort within the control of industry. The external inputs from government, the environmental community, and the public come through an advisory or externally negotiated role, rather than as a direct managing partner. This is not an insignificant issue because the magnitude of the overall effort is large, and historically industry has not been a big supporter of this type of effort. Industry may initially feel more comfortable retaining control if it moves actively into this area. Potential organizations to host this effort include the Natural Gas Council, Natural Gas Supply Association, American Gas Association, and Interstate Natural Gas Association of America.

A National, State, and Local Item For Industry, Government, and the Environmental Community: A joint partnership or consortium between industry, government, and environmental groups may be the boldest but most effective approach. The main objective of this approach is to correct a number of major misconceptions about natural gas during a period of time that the industry's credibility is near an all time low. The most effective and efficient approach in the long run may be to draw on the quality movement and include representation from client groups, or in this case, the marketing audience as part of the team. The short-term costs and administrative burdens and may be higher, and the up-front frustration may be higher because of the coalition-building requirements, but the long-term costs and ultimate prospects for success may be much greater. This approach also has a natural linkage with other recommendations aimed at developing more natural coalitions with consumer and environmental groups.

3. Form a joint industry, government, and environmental group coalition(s) to develop new ideas and concepts to facilitate compromise and progress rather than continued confrontation. Increase participation in existing public advisory committees created to provide input into the legislative, regulatory, and permitting process.

Initially a National Item For Industry, Government, and the Environmental Community: The purpose of this action item is to increase the industry's role in the public policy development process, particularly in forums that are not politically charged by a specific legislative, regulatory or leasing/permitting activity (i.e., an OCS lease sale or acquiring a drilling permit in a wetlands area). In effect, this is another form of problem solving, but this time in the public policy area. The goal is to open dialogues that will increase industry's knowledge of the public's goals and needs, identify emerging issues that will affect the natural gas industry, identify research needs, develop "natural" partnerships with consumer and environmental groups, and resolve problems before they become major legislative or regulatory issues. The optimum number of forums would have to be developed over time, based upon experience, but the concept is equally valid at the national, state, and local levels. The process would be started by creating one group at the national level and one at the state level (chosen to maximize the probability of success) and expanded as experience dictates.

The advantages of this item include greater input and insight into public policy decision making, developing potential partnerships with consumer and public interests groups to promote the environmental benefits of natural gas, minimizing the financial impacts of future environmental legislation and regulation, and improving access to potential new gas fields. Another advantage of the action item is that it requires no up-front costs to start other than manpower. The disadvantages are that it can be a time-consuming process that will tap already shrinking human resources, and there are no guarantees that groups outside the process will stop creating problems. The payout for this type of effort will develop over time and may not be immediately obvious in the time frames that industry decision makers are normally comfortable with. But the paybacks are potentially significant if public coalitions can be developed to help promote natural gas as an environmentally superior fuel and if industry can be positioned to minimize future environmental compliance costs.

RECOMMENDATION 4

Develop new innovative industry strategies to help better align industry's goals with the public's needs and expectations in order to create more timely and efficient solutions to environmental, permitting, and access issues (i.e., create win/win situations for industry, federal, state, and local governments, environmental groups, and the general public).

Like most businesses, the natural gas industry has traditionally planned and facilitated its activity through traditional business, engineering, and scientific processes without significant evaluation (other than natural gas consumption) of the goals, needs, and expectations of the general public. Consequently, the "public," which can significantly impact gas development through the government permit process, often stands in the way of new projects and demands to be included in the decision-making process. The basic objective under this recommendation is to develop and maintain a better understanding of the public's expectations for the gas industry relative to environmental issues, and to utilize this knowledge for the following purposes:

- Develop more effective industry advocacy strategies and positions on environmental legislative and regulatory initiatives
- Design exploration and production projects that meet not only industry's needs, but also the needs and expectations of the public.

In many respects this recommendation draws on one of the key elements of the "quality" movement that is currently sweeping the country's business community. That is, know your customers and design your business strategies to meet their needs and expectations. It represents a new approach to managing environmental issues, and it's an opportunity to create innovative solutions to emerging problems while at the same time developing business opportunities for the industry. It also recognizes the power that the general public and public interest groups can play in the regulatory and permitting process and attempts to integrate the natural gas industry's objectives with that power. The ultimate goal is to create win/win situations for industry, government, environmental groups, and the general public.

Implicit in this recommendation is the assumption that the general public is interested in playing a role in the decision-making process and is willing to participate in more timely and effective approaches than in the contentious, historical permit process. Industry's historical experience has been mixed, with some environmental groups and local governments apparently more interested in simply preventing development rather than working constructively toward solutions that are optimum for all parties involved. This recommendation, and its examples, represent opportunities for the industry to reach out to the public and begin the process of developing new, more constructive, and collaborative approaches.

The following items are examples of this kind of innovative or "breakthrough" thinking. In some cases, the examples are concepts that are currently being tried successfully in other industries; in other cases, they are merely the product of our brainstorming process. In any case, the actual application of these or any new innovative approach would have to be developed, evaluated, and applied on a case-by-case basis as the situation dictates. The recommendations are not intended to automatically apply, may not always be necessary or effective for all situations or for all parts of the country, and more importantly should not be mandated by federal, state, or local governments. The goal is to improve the efficiency of the process where it is not working well, not to increase costs where things are working well. Part of the implementation process for this recommendation would include a critical analysis of the local, regional, and/or national situation before developing a specific strategic action plan.

Implementing Items – The following are all Items for Industry

1. Develop new and innovative approaches to integrate constructive public input into the project development and permitting process in order to avoid unnecessary costs and delays.

In order to better align industry's efforts with the public's expectations, industry needs to develop new and innovative methods for identifying and staying abreast of the ever changing needs of the public. Normally, project design is well developed prior to any public review. As a result, the public has felt left out of the decision-making process and has perceived a lack of opportunity to influence the outcome of the project. This has resulted in confrontation and opposition, and often industry has been required to provide concessions, unrelated to requirements of the regulation, to appease a hostile public that has the power to obstruct the projects. The current process, which with increasing frequency is working less often, often results in a begrudgingly appeased public, a frustrated industry, and more often than not, a delayed and more expensive project.

To overcome this problem there is a wide spectrum of potential approaches available. Two examples are described below. The first is through the use of local community "thought leaders" as project consultants. A second and more aggressive example is the use of an adaptation of the negotiated rule-making process.

Example 1: The use of local community "thought leaders" as project consultants for project scoping, development, and/or implementation is an approach successfully pioneered by the Chemical Manufactures Association and is now being employed effectively by companies like Dow Chemical and DuPont. In this approach, a company selects one or more well-respected individuals from the community to work with the project team as consultants on issues of public concern. The advisors would be selected by the company based upon the company's own selection criteria. The selection criteria is company and site specific, but often includes many of the following qualifications: knowledge of the industry, knowledge of the local public issues, credibility with the local population and thought leaders, and, most importantly, a history of fairness. These advisors are used on either a continuous or periodic basis and play only a consulting role. They have no direct role in the final decision-making process. [Note: This item is similar in approach to Item 3 under Recommendation 3, except that the advisors in this case are consulting on specific project development issues rather than emerging general environmental issues.]

This approach has the advantages of thoughtful public input from credible, knowledgeable, and trusted leaders in the community, while still maintaining all the decision-making authority with industry. It also has the added advantage of creative input from outside of the normal company culture or paradigms. The disadvantages are that the general public may still feel left out of the process if the advisors are viewed as simply tools of industry or if industry is perceived to be ignoring public recommendations. The actual impact on project timing will be a function of how well the overall relationship works. Utilizing outside advisors may increase up-front timing some, and will undoubtedly add some initial frustration, but if the relationship is successful, it could result in significant savings in permitting time and mitigation costs.

Example 2: Another more aggressive example of new and innovative approaches to integrating constructive public input into the project development and permitting process would be to adapt the negotiated rule-making process, currently being used by the EPA in their regulatory process (fugitive emission regulations for chemical plants, reformulated gasoline regulations, etc.), for use in the project development and permitting process.

The current permitting process is a very public negotiation process that occurs in heated public forums often energized by the media and special interest groups. In this forum, true negotiation is impossible because each party has publicly staked out its position and any perceived compromise is seen as a compromise in values. The negotiated approach simply takes the existing negotiation process and allows it to occur between key interested parties outside of the formal regulatory process and away from the media. The negotiation process is initiated and completed before anyone has staked out an irreversible position and the negotiated settlement creates a strong bond among the participants to support and protect the agreement. A recent example of that mutual support occurred following the completion of the recent EPA negotiated rule making on reformulated gasoline. The petroleum industry, the EPA, and the environmental community stood together to prevent an attempt by another industry to circumvent the negotiated agreement.

For the negotiated rule-making approach to be effective, it must, at a minimum, meet the following important criteria:

- It must start early before people have staked out irreversible positions, and prior to initiation of administratively prescribed permit procedures.

- It must be facilitated by an impartial professional facilitator.
- It must have clearly established ground rules developed either through negotiation or by an impartial third party.
- There must be an up-front agreement on which interest groups will participate and who is going to represent each party (i.e., industry, environmental groups, the general public, etc.) so each negotiator has a clearly defined constituency and so each constituency speaks with a single voice.
- It must have a closure mechanism (including deadlines) to prevent any one participant from stonewalling the process.

This is clearly a bolder approach, but the potential benefits in reduced permitting time (by developing early consensus and support), reduced project costs (by eliminating unnecessary capital expenses for community enrichment/mitigation projects), and reduced future litigation (the number of cases and their corresponding costs and time delays) may be far greater. The early upstream experience with negotiated rule making for offshore air regulations in Santa Barbara and in permitting efforts in offshore North Carolina was not positive. In Santa Barbara the process started long after many of the participants had developed strong or irreversible positions, and in North Carolina the process was not successful after considerable investments of time and effort by all parties.

It is important to reiterate that the methodology and strategy employed to identify and meet the public's goals and expectations is a very site-specific process that requires careful analysis of not only the local/regional situation, but also the internal culture of the company involved. In fact, it becomes a site specific decision that can be only made by the specific company(s) involved.

2. Develop and/or participate in innovative cooperative community programs to create partnerships with local government and community interest groups.

Local communities are facing an ever-growing list of challenges that include: unemployment, affordable housing, financing public services, traffic management, pollution control and mitigation, infrastructure replacement, etc. To meet these challenges, local governments are looking for and turning to more innovative and non-traditional approaches to solving their problems. Given the growing community needs, which include environmental issues, an opportunity may exist for the natural gas industry to join with local communities to solve problems that would benefit both parties. The following is one of many examples.

Example: Develop and/or support comprehensive integrated community energy development, conservation, and management programs. This could include energy conservation/efficiency measures, transportation control measures (ride sharing, etc.), improved public transportation, natural gas vehicle fleets (public and private), and energy development opportunities. The objective is to align and couple natural gas development with local or regional energy management needs, while creating opportunities to promote the use of clean-burning natural gas.

The advantages of this approach include: solving some of the problems facing the communities; increasing the understanding of, and credibility for, the natural gas industry; reducing barriers to access; and increasing markets. The disadvantages are in potential increased up-front costs (which would be offset by reduced permitting and mitigation costs), increased coordinating efforts between upstream and downstream segments of the industry, the need to convince the industry to become much more involved in community infrastructure issues, and the need to develop more expertise on public issues typically outside the industry's normal area of business activity. These challenges may on the surface seem significant, but they may simply reflect the realities of successfully doing business in the future.

3. Improve the integration of environmental issues into strategic business-planning and decision-making processes.

Continuously increasing environmental requirements place a growing demand on the finite capital resources of the natural gas industry. These environmental demands combined with a weak economic climate have inhibited investment in natural gas development. Better tools are needed by the industry to deal with the uncertainties of environmental and business costs.

Example: One way to overcome this problem in the environmental area is to improve the methods used to account for environmental constraints in the industry's financial decision-making process. Today many of industry's environmental costs are not clearly accounted for in overall operating expenses (i.e., waste water treatment costs are billed against the facility effluent treatment plant rather than apportioned back to the individual originating sources, etc.). Compliance costs associated with future regulations are not adequately predicted. The goal of this example is to develop methodologies to identify and quantify current and future environmental costs and then include those costs in the industry's financial analyses of new investment opportunities as well as ongoing projects.

The advantages of this approach include a more accurate accounting of industry's environmental costs, more accurate data for project economics (for nonenvironmental projects, as well as for environmental projects), and most importantly, more accurate information for strategic business planning. The disadvantages are the resources required to do the work and the potential difficulty in accurately estimating the impact of future regulatory requirements. A joint natural gas industry/government effort to develop methodologies and guidance for estimating environmental costs could help bridge the gap between current financial analysis capabilities and the future need for a better understanding of environmental costs.

CHAPTER THIRTEEN

CONSUMER/PUBLIC EDUCATION PROGRAMS: ADDRESSING THE CONSUMER/PUBLIC PERCEPTION OF SUPPLY RELIABILITY

Gas demand was slow to respond to the market signals of the later part of the 1980s, including a plentiful supply and relatively low prices. This appears to be due, at least in part, to public and consumer concerns and misunderstandings about the natural gas supply outlook. Past government and industry pronouncements have portrayed a depleting reserve base. Such messages combined to create a lasting uncertainty in the minds of potential consumers, regulators, and other public interest parties about the long-term availability of natural gas.

For the market to expand, the misperceptions must be overcome and legitimate concerns addressed. The industry must not only work to educate and respond to consumer needs, but also to eradicate its own tendency to blame another part of the industry for failures in customer service. Supply, however, is only part of this picture of the failure in consumer confidence. A curtailed customer does not necessarily determine the theoretical availability of supply or analyze the cause for his failure to obtain his expected supply. He is unlikely to spend time analyzing whether a failure to receive his needed fuel was due to a resource problem separate from a delivery or infrastructure problem.

HISTORICAL PERSPECTIVE

Between 1972 and 1986, gas demand dropped 26 percent, from 22.7 trillion cubic feet to 16.7 trillion cubic feet. By 1990 demand had grown to 19.4 trillion cubic feet for an average annual growth rate since 1986 of slightly less than 4 percent.

The primary loss of markets between 1979 and 1986 was in industrial applications and electric generation (25 percent of the electric utility market; 19 percent of the industrial market). No substantial new markets were added to compensate for this loss. The curtailment policy of the 1970s contributed not only to this loss of market demand but set the stage for the continuing softness of consumer confidence in the long-term availability of natural gas.

The attitude associated with restricting natural gas markets was historically related to a desire to preserve what was believed to be a scarce and therefore "premium" value fuel—for premium, read primarily home-heating use. As a result of excessive federal regulation, shortages were created in fact, lending credence to the argument that natural gas should be limited to the most valuable uses as determined by government policy makers at the federal and state levels. Specific government edicts associated with President Carter's Market Orientation Program Planning Studies (MOPPS) (I & II) asserting the depletion of the resource and 1970s legislation prohibiting its use (The Power Plant and Industrial Fuel Use Act of 1978) were based on these perceptions of a limited resource base. The industry fed this attitude in its own public pronouncements by misapplication of reserve figures to characterize the resource as substantially depleted.

These historical events confound the industry's current efforts to change the public perception of the availability of natural gas via any short-term public education and advertising program. However, consumers and industry segments are expressing increasing confidence in the natural gas resource base. Experience with surplus supplies and the more positive outlook expressed by industry and government agencies are reaping rewards. The same growing confidence is not expressed in attitudes toward supply deliverability. Diminishing exploration activity is creating concern among some groups. Many parties await a possible shortfall in service even from a "normal" winter. Responding to these concerns is the major problem currently facing the industry with respect to supply.

Periodic pronouncements of impending gas shortages are used by competitors offering other fuels to attack the long-term reliability of natural gas in the marketplace. In some markets this drives existing customers to want to limit the access of new customers to natural gas from fear that the new demand will limit their ability to obtain supplies at current prices.

FOCUS GROUP RESULTS[1]

As part of the NPC study, 16 focus groups (including all key elements of the industry, regulators, customers, and suppliers) were queried about the conditions of the industry and the impediments it faces as it works toward increasing the efficient use of natural gas in the United States. Focus groups were used to obtain qualitative attitudinal information. The resulting comments are illustrative and only indicative of potential problems in image, perception, and actions. The challenges faced by the industry as identified by the combined comments of the participants of the focus groups are:

- Improve the image of the natural gas industry.
- Improve natural gas marketing. The natural gas industry must become market-driven.
- Develop a strong marketing function in the industry.
- Improve reliability.
- Reduce the impact of regulatory hurdles that impede growth of the industry.
- Develop pricing and cost structures that meet the needs of customers and providers.
- Improve the financial health of pipelines in order to improve their ability to expand to meet new demand.
- Improve product commercialization efforts.

The focus group responses as a whole are characterized as reflecting a deep-seated mistrust and dislike for segments of the natural gas industry among the various publics. The historical association with big oil and alleged abuse of market power taints concerns for the impact of deregulation. Participants believe that given their way, producers will abuse their market power to control transportation and gouge the captive customer. A major failure in marketing was identified—in particular, industry marketing programs appear to have failed to eliminate or effectively counter memories of curtailments from the 1970s or the more recent well freeze-offs and shortages of 1989. Compounding the negative impression these perceptions represent, is the lack of integrated, unbiased information available to consumers and regulators. Indeed, the information provided by industry segments is often viewed as self-serving and contradictory.

The participants were split on the outlook for supply deliverability. Some, including members of the regulatory and demand groups, believe that supplies will be adequate but only if prices rise substantially, possibly reaching the point where gas becomes unacceptably expensive. Other members of the regulatory, pipeline, and producer groups believe that because wellhead prices are currently so low, drilling is not adequate to maintain reserves, and shortages will ensue. Yet others, including members of the producer, demand, and regulatory groups, are unconcerned about the issue.

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[1] Final Report from Bentek Energy Research, *Understanding Barriers to and Opportunities for Increasing Natural Gas Consumption*, in Appendix C of Volume V, Regulatory and Policy Issues.

They believe that reserves will be added as needed without undue dislocations. These contrasting views illustrate the degree to which a better understanding is needed of the supply side of the natural gas business.

There is little doubt that supply-side participants contribute to the confusion. Participants in the state commission staff focus group noted: "The [major producers] that talk to us are increasingly aware of the fact that it's not a very good message to say that the bubble is almost over and the price is going to go up, you better lock in now. You still hear that from some of the smaller producers . . . The industry is its own worst enemy in the sense that it keeps saying it's going to run out of gas. Who's going to install equipment if the supply is going to disappear?"

Attitudes of commissioners and consumer advocates toward long-term contracts is a second example. Participants in the provider groups indicate that long-term contracts would add stability and predictability to the industry, and therefore promote reliability. On the other hand, regulatory group participants believe that long-term contracts entail too much price risk for the captive customers and, thus, should not be allowed under prudency review. The two positions appear to be irreconcilable, and both the customer and the providers are forced into the 30-day market.

In general, the perceived lower reliability of natural gas is creating a mentality that substantially discounts natural gas as an option in the regulatory review process. However, except for producers, focus group participants did not comment on regulatory burdens affecting supply.

OPTIONS

Industry and the federal government in particular (because of its past role in restricting natural gas use) need to respond to the comments made by consumer groups and regulators on the availability and deliverability of supply and the outlook for the price. Some options are:

Option: Consider using the opportunity of the NPC study to reverse public perception by employing a more active program to promote the study results than is perhaps usual for the National Petroleum Council. Major testimony by administration officials and a series of press releases by the Department of Energy (DOE), and possibly The White House, alerting and explaining to the nation's consumers, the changed outlook for natural gas use could be conducted. The DOE might consider seeking a non-binding resolution of Congress to help increase awareness about the availability of natural gas as a domestic fuel option. Moreover, the DOE might hire public relations professionals to design a public outreach program after the study's completion. And, the NPC and the DOE could coordinate with industry groups like the Natural Gas Council to promote or further investigate the recommendations of the NPC study.

Option: Actively market industry's new belief in the size of the resource base. Industry and government should make a joint long-term commitment to school education projects and education efforts at major trade meetings of other industries (after specifying targeted groups based on potential demand impacts).

Option: Have the DOE sponsor an annual or biannual government conference on energy forecasts to include a review of the implications of government forecasts in affecting fuel choices.

Option: The DOE and industry segments should provide information to state commissioners on industry ability to react positively to positive market signals; on the time needed to develop and deliver new supplies; on alternative inventory strategies (e.g., growth in supply area storage options); on increased success in finding and attaching new reserves; and on greater diversity of supply sources.

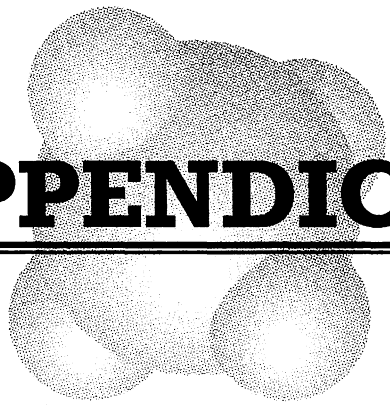
Option: Endorse joint industry-sponsored programs (such as recently formed joint associations' Natural Gas Council) on the "state" of the industry relative to supply and services; promote wide distribution of supply deliverability information to establish the capability of the supply industry such as the Energy Information Administration report and the Natural Gas Supply Association annual deliverability survey.

POLICY CONCLUSIONS AND RECOMMENDATIONS

- Time and experience will be the best marketing tool to overcome residual distrust of the natural gas industry. Customers are becoming increasingly bullish on natural gas availability with their continued experience that it remains plentiful. This attitude needs to be buttressed with wide dissemination of the results of the NPC study. A broad commitment is required on the part of both industry and government (because of the part each has played in the past that has helped to erode consumer confidence in the supply base) to demonstrate the dependability of natural gas in the future. However, if consumer confidence is to be achieved the messages should be highly credible and must be backed by performance.

- Practice what you preach: the natural gas industry should use its own product in new ways and advertise that usage to show customers its own belief in the reliability and future dependability of the supply base. The federal government should examine its own commitment to the use of gas in a multi-department/agency effort; usage should be publicly advertised, particularly in environmentally sensitive regions of the country.
- Actively educate state and federal regulators on the lack of market power in supply sources to enhance confidence in the competitive nature of the supply business and also to help consumer representatives in their efforts to build supply portfolios adequate to meet their needs.

APPENDICES



Appendix A

The Secretary of Energy
Washington, DC 20585

June 25, 1990

Mr. Lodwrick M. Cook
Chairman
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear ~~Mr. Cook~~ Lod:

Through this transmittal, I am formally requesting that the National Petroleum Council (NPC) perform two studies that are currently of critical interest to the Department of Energy. These studies are described below.

Constraints to Expanding Natural Gas Production, Distribution and Use

I request that the NPC conduct a comprehensive analysis of the potential for natural gas to make a larger contribution, not only to our Nation's energy supply, but also to the President's environmental goals. The study should consider technical, economic and regulatory constraints to expanding production, distribution and the use of natural gas. In the conduct of this study, I would like you to consider carefully the location, magnitude and economics of natural gas reserves, and the projected undiscovered and unconventional resource; the size, kind and location of future markets; the outlook for natural gas imports and exports; and potential barriers that could impede the deliverability of gas to the most economic, efficient and environmentally sound end-uses.

This study comes at a critical time, given the increased interest in natural gas, for developing public and private sector confidence that natural gas can make a greater contribution to the energy security and environmental enhancement of our Nation. I anticipate that the results of your work will be able to contribute significantly to the development of the Department's policies and programs.

The U.S. Refinery Sector in the 1990's

U.S. refineries face significant changes to processing facilities in the next decade, particularly in response to new environmental legislation that will affect emissions and waste disposal from refineries and the composition of motor fuels. Substantial investments are likely to be required to comply with proposed Clean Air Act Amendments, including provisions dealing with air toxics and alternative fuels. There is concern about the U.S. engineering and construction industry's capability to design, manufacture, and install quickly the large number of new, sophisticated processing facilities that would be necessary to supply these fuels.

Product imports, which are projected to increase, may also have to be treated differently than in the past. For example, if U.S. refiners have different gasoline specifications (e.g., Reid Vapor Pressure, aromatics, olefins, oxygen content) than foreign refineries, imported products may require additional U.S. refining.

I request that the NPC assess the effects of these changing conditions on the U.S. refining industry, the ability of that industry to respond to these changes in a timely manner, regulatory and other factors that impede the construction of new capacity, and the potential economic impacts of this response on American consumers.

I look forward to receiving your results from these two studies and would like to be notified of your progress periodically.

Sincerely,

Jim
James D. Watkins
Admiral, U.S. Navy (Retired)

DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council on June 18, 1946. In October 1977, the Department of Energy was established and the Council was transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to oil and natural gas or the oil and gas industries. Matters that the Secretary of Energy would like to have considered by the Council are submitted in the form of a letter outlining the nature and scope of the study. This request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Secretary of Energy include:

- *Unconventional Gas Sources* (1980)
- *Emergency Preparedness for Interruption of Petroleum Imports into the United States* (1981)
- *U.S. Arctic Oil & Gas* (1981)
- *Environmental Conservation—The Oil & Gas Industries* (1982)
- *Third World Petroleum Development: A Statement of Principles* (1982)
- *Enhanced Oil Recovery* (1984)
- *The Strategic Petroleum Reserve* (1984)
- *U.S. Petroleum Refining* (1986)
- *Factors Affecting U.S. Oil & Gas Outlook* (1987)
- *Integrating R&D Efforts* (1988)
- *Petroleum Storage & Transportation* (1989)
- *Industry Assistance to Government* (1991)
- *Short-Term Petroleum Outlook* (1991)
- *Petroleum Refining in the 1990s–Meeting the Challenges of the Clean Air Act* (1991).

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of the oil and gas industries and related interests. The NPC is headed by a Chairman and a Vice Chairman, who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

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APPENDIX C

NORTH AMERICAN REGIONAL GAS MODEL

The North American Regional Gas (NARG) Model is an application of the Generalized Equilibrium Modeling System (GEMS). GEMS is a software package developed by Decision Focus, Inc., to facilitate the construction of large-scale economic models that consist of systems of linked submodels. The NARG model is a regionally disaggregated computer simulation of the continental gas supply, transportation, and consumption systems represented by approximately 20 supply regions, 15 demand regions, and over 100 interconnecting pipeline links. NARG calculates market clearing prices and quantities simultaneously at all points throughout the system such that the entire continental gas market is in balance.

In using the NARG model, the user specifies data on gas resource availability and costs, initial demand conditions, economic growth factors, oil prices, and pipeline rates and capacities. With these inputs the model solves for the pattern of supply and transportation that simultaneously minimizes consumer costs and maximizes producer value at the wellhead. Reports generated include:

- Prices that balance supply and demand
- The amount of gas produced in the supply regions
- Final demand
- Gas flows over the pipeline network.

The model projects how the North American gas system would operate given perfect economic foresight, fully competitive markets, and economically optimal production, transmission, and consumption. NARG is useful for testing alternative assumptions about uncertain variables—not by looking at the results of any single scenario or "model run"—but by analyzing the direction and magnitude of changes in results between scenarios.

The version of NARG used by the NPC incorporated the latest demand data specified by the U.S. Gas Research Institute (GRI) and the National Energy Board of Canada, and the most recent gas resource and cost information from the GRI, the Potential Gas Committee/Geological Exploration Associates, the U.S. Geological Survey, the U.S. Department of Energy, the National Energy Board of Canada, and the Canadian Energy Research Institute.

Moreover, the NPC version included updates and modifications to these data as specified by various users of the model, including the California Energy Commission, the National Energy Board of Canada, the Canadian Energy Research Institute, and various other producer and pipeline company users in both the United States and Canada.

NPC changes to the existing NARG model included:

- Added Northern Network Detail: Allows for segmented development of northern Canadian Frontier and Alaskan supplies.
- Increased Mainland Territories/Frontier Resources: Potential exists for higher resource estimates.
- Split Alberta Connected/Unconnected: About one-third of proved reserves are

unconnected. Added $0.40 per thousand cubic feet incremental connection charge to unconnected supply costs.

- Added Canadian "Tight:" All nonconventional gas was lumped together. Used GRI cost structure.
- Added Canadian Coalbed Methane: Used GRI cost structure times 1.25.

Table C-1 shows a list of the NARG model assumptions and input variables used by the NPC study group, and Table C-2 describes the sensitivity cases run.

TABLE C-1

NORTH AMERICAN REGIONAL GAS MODEL ASSUMPTIONS AND INPUT VARIABLES

1. Reserves/ Resources Data	– Conventional Resources: Canadian Petroleum Association/National Energy Board of Canada/ Geological Survey of Canada/Canadian Oil and Gas Lands Administration
	– Unconventional Resources: Various Sources
2. ANGTS Pipeline	– Single line to Caroline
	– Developed per Williams/Foothills Application
	– Segmented development approach
3. Mackenzie Delta	– Developed per Gulf/Esso/Shell Application
4. Pipeline Tariffs	– Developed from published data
5. Canadian/U.S. Border Crossings	– Huntingdon (Northwest Pipeline)
	– Emerson (Great Lakes, Viking)
	– Kingsgate (Pacific Gas Transmission/Altamont)
	– Niagara (Tennessee Gas Pipeline)
	– Monchy (Northern Border)
	– Iroquois
	– No Capacity Constraints
	– Border crossings allowed to expand as needed
6. U.S./Canadian Border Crossings	– St. Clair
7. Demand	– National Energy Board of Canada (Preliminary Supply/Demand Report — November 1990)
8. Oil Price	– Preliminary Oil Price Assumption for NPC study
9. Reserves-to-Production Ratio	– 10/1 for Conventional resources
	– 15/1 for Coalbed Methane
10. Market Factors	– Discount Rate: 7 to 8 percent Real Before Tax
	– Tax: Leveraged Cost of Capital (10 percent Equalized/ 4 percent Depreciation)
11. LNG Imports	– Existing terminals allowed to expand to maximum expansion capacity
	– No new facilities built in foreseeable future
12. Mexican Imports	– Limited to 1 TCF per year capacity
	– $4.00/MCF Delivery Charges ($3.50/MCF at wellhead + $0.50/MCF for national pipeline expansion)

TABLE C-2

NORTH AMERICAN REGIONAL GAS MODEL ASSUMPTIONS SENSITIVITY CASES

1. **High Resource Case:**
   - Increase resource estimates as follows:

British Columbia	30 to 50 TCF	(67%)	+20 TCF
Alberta	130 to 200 TCF	(54%)	+70 TCF
Saskatchewan/Others	8 to 10 TCF	(25%)	+ 2 TCF
Tight Gas	50 to 100 TCF	(100%)	+50 TCF
Coalbed Methane	50 to 100 TCF	(100%)	+50 TCF
Frontier Areas	286 to 356 TCF	(25%)	+72 TCF
Total Increase	**554 to 818 TCF**	**(48%)**	**+264 TCF**

2. **High Supply Cost Case:**
   - Assumes that supply costs in North American Regional Gas Model are understated due to one or more:
     - Land Access and/or Other Bottlenecks
     - Royalties
     - Uncertainty
     - Reserves-to-Production Ratio
   - Higher supply costs
     - 1.25 times conventional resource costs
     - 1.50 times nonconventional costs
     - No change (lowering) of resource size.

3. **Slow Canadian Export Case:**
   - Export capacity growth limited to current pipeline project proposals.
   - Projects will proceed only if economic.
   - Current pipeline capacity is maximum for ± 10 years.
   - Exports limited to:
     - 2.1 TCF through 1999
     - 2.3 TCF through 2004
     - 2.5 TCF through 2009

4. **Aggressive Frontier Development Case:**
   - Segmented development approach of Northern Canadian Frontier/Alaska
   - Allows Mackenzie Delta/Beaufort development time to be accelerated
   - Development of Alaska Natural Gas Transportation System also pushed forward.

5. **Contractual Rigidity Case:**
   - Recognizes firm transport contracts held by Canadian shippers on U.S. pipelines
   - Allows exports on systems (e.g., Altamont/Northern Border) on which they own capacity rights.

6. **Flat Oil Price Case:**
   - Any or all above cases to be examined at flat oil prices if warranted.

APPENDIX D

LNG SAFETY

Liquefied natural gas (LNG) by its nature is a safer substance than gasoline, chemical products, or even conventional vaporous methane gas. In its liquid state, LNG cannot explode or even burn. To become a useable fuel, LNG must be regasified and then, like all natural gas, it must be mixed with air in specific proportions before it can be ignited. While no energy project is absolutely risk free, the LNG industry has incorporated state-of-the-art materials, as well as redundant control and monitoring systems, into each phase of an LNG project to ensure that operations are as safe as possible.

In U.S. industry practice, LNG storage tanks are double-walled: an inner wall constructed of 9 percent nickel steel or aluminum surrounded by a carbon steel outer wall. Figure D-1 is a diagram of a typical LNG storage tank. High nickel content steel or aluminum are used for their proven stability in containing cryogenic liquids. Each tank is surrounded by a dike system capable of containing the entire contents of the tank. All LNG piping and handling equipment is constructed of cryogenically proven material and is surrounded by barriers designed to contain the LNG in the unlikely event of a spill or leak.

LNG receiving and regasification terminals employ several different types of fire fighting equipment. There are high expansion foam generators, water deluge systems, dry chemical systems, and mobile fire fighting equipment that would be activated if there was a spill or fire. A variety of sensors are used to detect LNG spills, gas leaks, and fires. They range from ultraviolet fire detectors to low temperature sensors that would detect LNG spills.

LNG vessels are some of the most sophisticated in the world, with the most current navigation and maneuvering equipment and comprehensive electronic cargo surveillance equipment. In 1990, 63 vessels were in service worldwide, transporting 1,321 cargoes of LNG. Since LNG vessel operations began in 1964, over 15,000 round-trip voyages have been made without a serious injury or loss of cargo.

Design of LNG terminals and tankers takes into account the specific characteristics of LNG in order to secure maximum operational safety. Baseload LNG receiving terminals have been operating in the United States for over 20 years and have an excellent safety record.

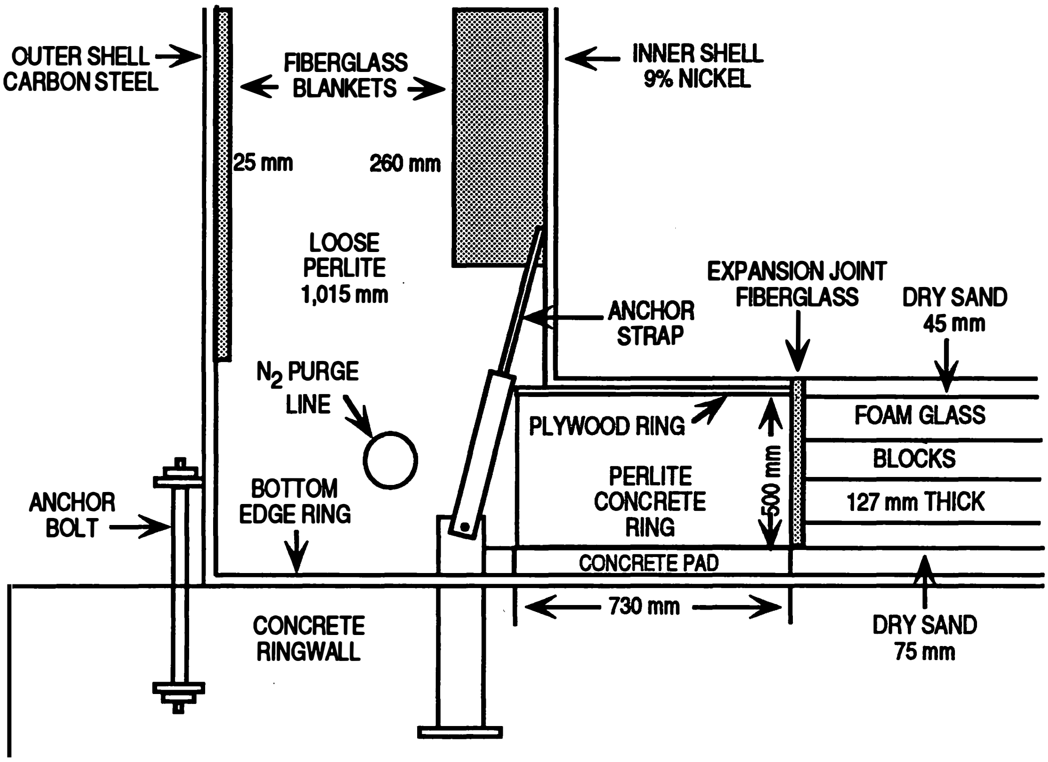

Figure D-1. Detail of Tank Construction at Outer Shell.

APPENDIX E

LNG PROJECT COMPONENTS

Liquefied natural gas (LNG) projects are capital-intensive ventures involving three integrated components: (1) liquefaction facilities, (2) shipping, and (3) regasification facilities. All of these components must work in unison for the project to be successful. Below is a brief discussion of each of the three elements.

LIQUEFACTION FACILITIES

A liquefaction plant typically consists of feedstock preparation facilities, refrigeration equipment, LNG storage facilities, and docking and loading facilities for LNG tankers. The plant usually consists of two or more independently operable production lines, known as trains, each capable of annual production of 2 to 2.5 million metric tons of LNG (equivalent of 250 to 275 million cubic feet per day of natural gas). Once the natural gas has been liquefied, it is stored in specially designed double-walled tanks. LNG is maintained in a liquid state by a highly efficient insulation system that surrounds the inner tank. When needed, the LNG is pumped to specialized tankers for transport to the regasification facility.

Liquefaction plants are very capital-intensive. A two-train plant would cost a minimum of $1.8 to $2.0 billion (1991$) to construct.

LNG TANKERS

The vessels that transport LNG are some of the largest and most complex in the world. Vessels transporting LNG to the United States are of the 125,000 m^3 class (comparable in size to an aircraft carrier), stretching more than 930 feet in length with a beam of approximately 140 feet. They draw about 36 feet of water when loaded and have a cruising speed of 18 to 20 knots. Because of their sophisticated containment systems and the cryogenic materials required, these vessels are quite expensive compared to a crude oil tanker. Construction time is approximately three years, at a cost of $260 million (1991$). One 125,000 m^3 class LNG tanker can deliver the equivalent of 2.6 to 2.7 billion cubic feet of natural gas per voyage.

During a voyage, the LNG is maintained in a liquid state by highly efficient insulation that surrounds the cargo tanks. Since no insulation system is perfect, a small amount of LNG (daily rates of 0.1 to 0.25 percent of the initial loaded volume) vaporizes in transit. This boil-off gas helps to auto-refrigerate the remaining LNG, keeping it in the liquid state. Boil-off is also used to supplement bunker fuel in powering the vessel.

RECEIVING AND REGASIFICATION TERMINALS

Receiving and regasification terminals are designed to perform three functions: (1) berth and unload LNG tankers, (2) provide LNG storage, and (3) regasify the LNG for pipeline delivery. LNG is delivered to the terminal and stored in its liquid form. It remains a liquid until it is pumped from the storage tanks and subjected to both heat and pressure to return it to its gaseous state for transportation by natural gas pipeline to the ultimate user. A small amount of LNG imported to the United States is sold and trucked in liquid form to satellite storage and regasification facilities for use in peak shaving.

The United States has very stringent regulations regarding siting, construction, and operation of LNG facilities, particularly siting of LNG storage tanks. Re-opening, expansion, or new construction of LNG facilities requires approval by the Federal Energy Regulatory Commission and other government agencies.

APPENDIX F

LNG STUDY ASSUMPTIONS
CALCULATIONS

TABLE F-1

ESTIMATED GAS PRODUCTION AND LIQUEFACTION COSTS FOR VENEZUELA (1991$)

Millions of Dollars			Dollars per Thousand Cubic Feet§			
Capital Cost*	Annualized Capital Cost†	Annual O&M Costs‡	Prod.	Capital	O&M	Total
2,000	411	61	1.000	2.009	0.300	3.310

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* Based on average cost of a grassroots 4 million tons per year (500 million cubic feet per day) plant; if published estimate of $1,300 million (1989$) is correct, total liquefaction cost will decrease from $2.309/MCF to $1.619/MCF ($1.394 capital plus $0.225 operating & maintenance (O&M) expenses).

† Assuming 20-year life and 20% discount rate, annual capitalization factor is 4.870.

‡ Operating & maintenance costs include: $0.5 million for catalyst & chemicals; $11 million for labor, overhead, and general and administrative expenses; $20 million for maintenance materials and labor; and $30 million for insurance, property taxes, etc.

§ Based on liquefied natural gas production equivalent to 560 million cubic feet per day of gas.

TABLE F-2

LNG TRANSPORTATION COST TO U.S. TERMINALS

Terminal	One-Way Distance	Round-Trip Days*	Voyages per Year*	Volume Delivered per Voyage† (BCF)	Total Volume per Year (BCF)	Delivered Shipping Cost ($/MCF)‡		
						Current Project	New Vessel	Used Vessel
Everett, MA								
Algeria	3,300	18.3	19	2.611	49.6	$0.370	$0.984	$0.404
Nigeria	4,975	26.0	13	2.578	33.5		$1.420	$0.561
Venezuela	2,000	12.3	28	2.637	73.8		$0.666	$0.276
Lake Charles, LA								
Algeria	5,000	26.1	13	2.577	33.5	$0.274	$1.432	$0.573
Nigeria	6,100	31.2	11	2.556	28.1		$1.687	$0.662
Venezuela	2,300	13.6	25	2.631	65.8		$0.742	$0.304
Cove Point, MD								
Algeria	3,670	20.0	17	2.604	44.3	N/A	$1.096	$0.445
Nigeria	5,330	27.7	12	2.571	30.9		$1.538	$0.605
Venezuela	1,900	11.8	29	2.639	76.5		$0.643	$0.267
Elba Island, GA								
Algeria	3,990	21.5	16	2.598	41.6	N/A	$1.165	$0.472
Nigeria	5,100	26.6	13	2.575	33.5		$1.423	$0.562
Venezuela	1,700	10.9	31	2.643	81.9		$0.603	$0.252

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* Round-trip days calculated based on 18 knot speed with 3 port days; trips per year based on 340-day operating year.

† Delivered volumes based upon a loaded volume of 2.690 BCF per voyage (typical 125,000 m^3 tanker) less boil-off of 0.16% loaded volume per day.

‡ Delivered shipping cost for new and used vessels is based upon full cost recovery.

Table F-2 (Continued)

Calculations:

Shipping Cost

Bunker Consumption	55 metric tons per day @ $100/ton in 1991$; escalation with crude oil
Nitrogen consumption	7,000 gallons per voyage @ $0.30/gallon in 1991$; escalation with inflation
Port Costs	U.S.A. $50,000 per voyage, Algeria $80,000 per voyage, Other Foreign $50,000 per voyage

Total Freight Cost

Current Projects:
Everett, Massachusetts: $0.27/MMBTU Loaded + Bunkers + Nitrogen + 50% Port Costs
Lake Charles, Louisiana: $0.192/MMBTU Loaded + Bunkers + Nitrogen

New Projects:

Item	**New Vessel**	**Used Vessel**	
Estimated Vessel Cost	$260.0	$60.0	
Capital Cost @ 12%, 20 years	34.8	8.0	
Crew Cost (U.S. flag)*	4.0	4.0	
Maintenance & Repair	1.0	1.0	+ Bunkers + Nitrogen + Port Costs
Administrative & General	2.0	2.0	
Insurance @ 1% of value	2.6	0.6	
Total Annual Operating Cost (excl. bunkers, nitrogen, and port costs)	**$44.4**	**$15.6**	

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* If vessels are foreign flag, crew costs are approximately $2.2 million per year.

Costs were estimated from industry standards.

TABLE F-3

LNG TERMINALLING COSTS

Terminal Location	Operating Volume Level (MMCF/D)	Incremental Expansion Volume (MMCF/D)	Annualized Capital Cost ($M)	Terminalling Rate ($/MCF)		
				O&M	Capital Recovery	Total
Everett, Massachusetts	100			$0.411		$0.411
	120			0.342		0.342
Total Expansion Costs	140			0.294		0.294
$8 Million	160			0.257		0.257
	180			0.228		0.228
	200			0.205		0.205
Existing Capacity: 240 MMCF/D	220			0.187		0.187
Expanded Capacity: 315 MMCF/D	240			0.171		0.171
	260	20	1,208	0.158	0.165	0.324
	280	20	1,208	0.147	0.147	0.230
	300	20	1,208	0.137	0.055	0.192
	315	15	1,208	0.130	0.044	0.175
Lake Charles, Louisiana	100			0.411		0.411
	200			0.205		0.205
Total Expansion Costs	300			0.137		0.137
$65 Million	400			0.103		0.103
	500			0.082		0.082
	600			0.068		0.068
Existing Capacity: 600 MMCF/D	700	100	9,814	0.059	0.269	0.328
Expanded Capacity: 1,000 MMCF/D	800	100	9,814	0.051	0.134	0.186
	900	100	9,814	0.046	0.090	0.135
	1,000	100	9,814	0.041	0.067	0.108

TABLE F-3 (Continued)

Terminal Location	Operating Volume Level (MMCF/D)	Incremental Expansion Volume (MMCF/D)	Annualized Capital Cost ($M)	Terminalling Rate ($/MCF)		
				O&M	Capital Recovery	Total
Cove Point, Maryland	100	-	4,530	0.411	0.124	0.535
	200	-	4,530	0.205	0.062	0.268
	300	-	4,530	0.137	0.041	0.178
	400	-	4,530	0.103	0.031	0.134
	500	-	4,530	0.082	0.025	0.107
Total Expansion Costs	600	-	4,530	0.068	0.021	0.089
$140 Million	700	-	4,530	0.059	0.018	0.076
	800	-	4,530	0.051	0.016	0.067
	900	-	4,530	0.046	0.014	0.059
Existing Capacity: 1,000 MMCF/D	1,000	-	4,530	0.041	0.012	0.054
Expanded Capacity: 1,400 MMCF/D	1,100	100	25,668	0.037	0.703	0.741
	1,200	100	25,668	0.034	0.352	0.386
	1,300	100	25,668	0.032	0.234	0.266
	1,400	100	25,668	0.029	0.176	0.205
Elba Island, Georgia	100	-	2,718	0.411	0.074	0.485
	150	-	2,718	0.274	0.050	0.324
Re-start Costs	200	-	2,718	0.205	0.037	0.243
$18 Million	250	-	2,718	0.164	0.030	0.194
	300	-	2,718	0.137	0.025	0.162
Total Expansion Costs	350	-	2,718	0.117	0.021	0.139
$100 Million	400	50	17,816	0.103	0.976	1.079
	450	50	17,816	0.091	0.488	0.579
Existing Capacity: 350 MMCF/D	500	50	17,816	0.082	0.325	0.408
Expanded Capacity: 600 MMCF/D	550	50	17,816	0.075	0.244	0.319
	600	50	17,816	0.068	0.195	0.264

Assumptions:

(1) Annual Capitalization Factor: 6.623 (based on 20 years @ 14%).

(2) Capitalization applies only to reopening and expansion costs; original construction costs are considered sunk.

(3) Annual operating and maintenance costs for each terminal were assumed to be $15 million.

APPENDIX G

LNG SALES PRICE AND IMPORT VOLUMES

TABLE G-1

LNG SALES PRICE AND IMPORT VOLUMES – EVERETT, MASSACHUSETTS

	Moderate Energy Growth Scenario			Low Energy Growth Scenario		
	LNG Price	LNG Import Volumes		LNG Price	LNG Import Volumes	
Year	$/MMBTU*	BCF/year	MMCF/D	$/MMBTU*	BCF/year	MMCF/D
1992	2.09	40	110	2.04	40	110
1993	2.31	52	142	2.14	40	110
1994	2.53	73	200	2.27	40	110
1995	2.80	81	222	2.40	52	142
1996	3.02	91	249	2.64	82	225
1997	3.17	107	293	2.74	107	293
1998	3.32	113	310	2.92	113	310
1999	3.53	113	310	3.04	113	310
2000	3.76	113	310	3.20	113	310
2001	3.75	113	310	3.28	113	310
2002	3.69	113	310	3.29	113	310
2003	3.68	113	310	3.28	113	310
2004	3.67	113	310	3.26	113	310
2005	3.63	113	310	3.30	113	310
2006	3.62	113	310	3.36	113	310
2007	3.75	113	310	3.45	113	310
2008	3.99	113	310	3.56	113	310
2009	4.32	113	310	3.62	113	310
2010	4.40	113	310	3.61	113	310

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* Prices in 1990$; LNG receives a 7.5% premium over spot gas prices in the market area served by the terminal.

TABLE G-2

LNG SALES PRICE AND IMPORT VOLUMES – LAKE CHARLES, LOUISIANA

	Moderate Energy Growth Scenario			Low Energy Growth Scenario		
	LNG Price	LNG Import Volumes		LNG Price	LNG Import Volumes	
Year	$/MMBTU*	BCF/year	MMCF/D	$/MMBTU*	BCF/year	MMCF/D
1992	1.42	40	110	1.38	40	110
1993	1.64	40	110	1.48	40	110
1994	1.86	40	110	1.61	40	110
1995	2.13	40	110	1.73	40	110
1996	2.35	40	110	1.98	40	110
1997	2.50	65	178	2.07	40	110
1998	2.66	115	315	2.25	40	110
1999	2.86	140	384	2.38	65	178
2000	3.10	140	384	2.54	115	315
2001	3.09	140	384	2.61	140	384
2002	3.02	140	384	2.62	140	384
2003	3.01	140	384	2.61	140	384
2004	3.00	140	384	2.59	140	384
2005	2.97	140	384	2.63	140	384
2006	2.96	140	384	2.70	140	384
2007	3.09	140	384	2.78	140	384
2008	3.32	140	384	2.89	140	384
2009	3.66	140	384	2.96	140	384
2010	3.73	140	384	2.95	140	384

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* Prices in 1990$; LNG receives a 7.5% premium over spot gas prices in the market area served by the terminal.

TABLE G-3

LNG SALES PRICE AND IMPORT VOLUMES – COVE POINT, MARYLAND

	Moderate Energy Growth Scenario			Low Energy Growth Scenario		
	LNG Price	LNG Import Volumes		LNG Price	LNG Import Volumes	
Year	$/MMBTU*	BCF/year	MMCF/D	$/MMBTU*	BCF/year	MMCF/D
1992	1.94	0	0	1.89	0	0
1993	2.16	0	0	1.99	0	0
1994	2.38	0	0	2.12	0	0
1995	2.64	0	0	2.25	0	0
1996	2.87	0	0	2.49	0	0
1997	3.02	0	0	2.59	0	0
1998	3.17	0	0	2.77	0	0
1999	3.38	0	0	2.89	0	0
2000	3.61	0	0	3.05	0	0
2001	3.60	0	0	3.13	0	0
2002	3.54	0	0	3.14	0	0
2003	3.53	0	0	3.13	0	0
2004	3.52	0	0	3.11	0	0
2005	3.48	0	0	3.15	0	0
2006	3.47	0	0	3.21	0	0
2007	3.60	0	0	3.30	0	0
2008	3.84	0	0	3.41	0	0
2009	4.17	0	0	3.47	0	0
2010	4.25	0	0	3.46	0	0

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* Prices in 1990$; LNG receives a 7.5% premium over spot gas prices in the market area served by the terminal.

TABLE G-4

LNG SALES PRICE AND IMPORT VOLUMES – ELBA ISLAND, GEORGIA

	Moderate Energy Growth Scenario			Low Energy Growth Scenario		
	LNG Price	LNG Import Volumes		LNG Price	LNG Import Volumes	
Year	$/MMBTU*	BCF/year	MMCF/D	$/MMBTU*	BCF/year	MMCF/D
1992	1.84	0	0	1.80	0	0
1993	2.06	0	0	1.89	0	0
1994	2.28	0	0	2.02	0	0
1995	2.55	0	0	2.15	0	0
1996	2.77	0	0	2.40	0	0
1997	2.92	0	0	2.49	0	0
1998	3.07	0	0	2.67	0	0
1999	3.28	0	0	2.80	0	0
2000	3.52	0	0	2.96	0	0
2001	3.50	0	0	3.03	0	0
2002	3.44	0	0	3.04	0	0
2003	3.43	0	0	3.03	0	0
2004	3.42	0	0	3.01	0	0
2005	3.38	0	0	3.05	0	0
2006	3.38	0	0	3.12	0	0
2007	3.50	0	0	3.20	0	0
2008	3.74	0	0	3.31	0	0
2009	4.07	0	0	3.38	0	0
2010	4.15	0	0	3.46	0	0

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* Prices in 1990$; LNG receives a 7.5% premium over spot gas prices in the market area served by the terminal.

APPENDIX H

TECHNOLOGY LIST

EXISTING TECHNOLOGIES

- 2D-3D Seismic Processing (Signal Proc)
- Acid Frac Stimulation
- Advanced Drill String Measure System
- Artificial Intelligence & Expert Systems
- Air Drilling
- Amplitude Versus Offset (AVO)
- Analytical Instrumentation
- Automation Technology
- Basin Analysis
- Bright Spot
- CAT Scanning Cores
- Cementing
  - High Temperature
  - Low Density
  - Mud to Cement
- Clastic & Carbonate Geological Models
- Co-Production
- Coalbed Methane Production Tech.
- Computer Integration
- Cross Well Tomography
- Directional Drilling
- Downhole Instrumentation
- Encapsulated Breakers
- Environmental Compliance
- Formation Damage Control
- Fracture Models
- Fracturing
- Geochemical/Acidizing model
- GeoChem Analysis
  - Source Rock Geochemistry
  - Source Rock as Reservoir Rock
- Geopressured Gas Reserves Prediction
- Geostatistic Fractal Geometry
- Gravel Pack Tech
- H_2S Cleanup
- Higher Prop Concentration
- Horizontal Well Completions
- Hydra Frac Geometry
- Improved Fracturing Fluids
- Improved Pressure Tcom (Well Int)
- Logging Tools
- Magnetic Resonance Imaging (MRI)/ Nuclear Magnetic Resonance (NMR)
- Massive Hydraulic Fracturing
- Material Tech – Sour Environment
- Monitoring While Drilling (MWD) Tech
- Natural Fracture Detection
- Perforating Tech

Polycrystalline-Diamond-Compact (PDC) Bits
Polymer Based Drilling Fluid
Produced Water Cleanup
Production Chemistry
Production Data Handling
Propellant Fracturing
Reservoir Description/Modelling
Reservoir Pressure Testing
Restored State Core Analysis
Satellite Remote Sensing
Slimhole Drilling
Steerable Drill Bits
Sub-Sea Well Comp
Tectonics
Tension Leg Platforms (TLP)
Top Drive Drilling
Vertical Seismic Profile (VSP)
Water Shut-Off
Well Cleanup
Workovers

FUTURE TECHNOLOGIES

Advanced Geophysics
3 Phase Flow Meter
Bio-Technology for Waste Disposal
Bio-Technology Operating on Heavy Oil
Cheaper Directional Drilling
Coiled Tube/Casing Drilling
Compressor Technology: Low Cost in Field, Low Noise
Computer Based Training & Technology Access
Computer Data Integration
Deep Gas Requirements
Corrosion Resistance (Corrosion Resistant Alloys) for Deep, Hot, Sour Gas Completions
Disposable Drill Bits
Drill without Waste
Efficient Non-Damaging Frac Treatment
Enhanced Coalbed Methane Recovery
Enhanced Gas Recovery
Expert Systems/Artificial Intelligence
Fully 3-D Frac Model-Real Time Control
Gas Drag Reduction
Geochemical/Acidizing model
Geographic Information Systems
High Temperature Acidizing Techniques & Computer Models
High Temperature, non-oil-based Drilling Fluid
Horizontal Well Stimulation
Hydraulic Fracture Diagnostics—Geometry Measurement
Improved 3-D Seismic
Improved Downhole Source for Tomography
Improved Flow Measurement & Transmission of Data
Improved Logging Tools
Improved Understanding of Reservoir Geometry
Log Interpretation in Horizontal Wells
Multi-Component Seismology
Multi-Phase Pump
NORM Disposal Techniques
Porosity Prediction Reliability
Real Gas Content Log for Shale & Coal
Real Permeability Log
Safety – More Remote and Automatic Operations
Sensor Technology
Separation of Dissolved Organics from Produced Water
Separation Technology
Separation Technology for CO_2 & N
Short Radius Drilling Techniques
Through Casing Pressure Detector
Vertical Permeability Measurement
Water Shut-Off Process

APPENDIX I

ICF RESOURCES, INC.
REPORT ON HISTORICAL TECHNOLOGY IMPACT

September 9, 1991

MEMORANDUM

TO: NPC Technology Work Group

FROM: Michael Godec, ICF Resources Incorporated

SUBJECT: Progress Report No. 2

The purpose of this memo is to update the NPC Technology Work Group on progress to date on our analysis of the impact of technology on the costs of developing and producing domestic natural gas. This report focuses on progress made since the Work Group meeting held July 24, 1991, at ARCO's offices in Plano, Texas.

Specifically, the memorandum addresses the following:

Drilling Costs

- Brief overview of the methodology for drilling costs.
- Summary of methodological and data improvements made in the drilling cost analysis since the July 24, 1991 Work Group meeting.
- Presentation of results to date for drilling costs.

Other Gas Development and Production Costs

- Overview of methodology employed for other, non-drilling cost categories.
- Presentation of results to date for the non-drilling cost categories.

Overview of Drilling Cost Methodology

As described in our July 19, 1991 memo to the Work Group and in our presentation at the July 24, 1991 Work Group meeting, our objective in this effort was to develop a model for historical drilling costs that provided both a good statistical "fit" and was conceptually satisfying; i.e., providing a reasonable explanation for the relationships postulated. After investigating several alternative models for representing historical drilling costs, we concluded that the most appropriate model was a three-equation model that characterized both the supply of and demand for drilling. This model formulation for drilling costs was selected because it separately represents the short-run utilization effects on drilling costs and the long-term impacts of technological change. The functional relationships for the three-equation model are as follows:

- In the demand for drilling equation, the quantity of drilling is represented as a function of the price of drilling, oil and gas prices, reserve additions per well, and the rate of production from existing wells.
- In the supply of drilling equation, the price of drilling is represented as a function of the quantity of drilling, hourly wage rates for oil and gas workers, average depth for drilling, and the availability of the domestic rig fleet.
- The supply of rigs is determined by a stock flow process, with supply of rigs represented as a function of the lagged stock of rigs and the lagged price of drilling.

With the statistical regression package used for this analysis, the dependent variables (i.e., quantity of drilling, price of drilling, supply of rigs) can be in any or all of the three equations and on either side of the equal sign.

Using the three equations described above, 12 possible variations of the multiple equation model were evaluated. These versions differ in the representation used for drilling costs. Using the Independent Petroleum Association of America (IPAA) data on the distribution of drilling and completion costs by category, the portion corresponding to various cost components were subtracted from the JAS drilling cost data for lower-48 wells. Various components of drilling costs, such as completion costs and other cost items that may cause a well today to be different from a well drilled in 1970 (such as fuel costs or directional drilling services), were removed. Table 1 summarizes the categories from the IPAA survey as we have grouped them. The values for 1974 and 1989 were compared since, in real terms, drilling costs in those years were roughly equivalent. For example, as shown in the table, well costs have decreased from 78 percent of total drilling costs in 1974 to 68 percent in 1989, with the largest decreases in the cost for drilling contractors, casing, and tubing. Over this same period, the portion attributable to completion and equipment costs rose from 9 to 14 percent. Other large areas of cost proportion increases include supervision and overhead costs (growing from 2 to 6 percent of total costs), and the costs for other expenditures (which grew from 5 to 7 percent of total costs).

These items have been grouped together and analyzed as follows:

- First, all completion and equipment costs were removed from the drilling expenditures survey results (to be analyzed separately), to attempt to arrive at "pure" well costs.
- Second, fuel costs for drilling were also removed from the total, assuming that fuel use efficiencies have improved considerably over the last two decades.
- Third, the cost of well services was removed, under the assumption that the types of services provided today are different than those provided in the early 1970s.
- Fourth, the cost of supervision and overhead was removed, under the hypothesis that overhead rates and related administrative costs are different today than in the early 1970s, especially as the mix of drilling between majors and independents has changed.
- Fifth, the "other" expenditures category was removed. This category included certain costs, such as depreciation and rig maintenance costs that may be allocated to well drilling, which could have changed over the last decade.
- Sixth, drilling expenditures were adjusted by subtracting completion and equipment costs, supervision and overhead costs, and other costs for depreciation and rig maintenance.

Our first set of analyses considered drilling costs, assuming an average well in the lower-48 onshore. Since average well depth could be a major factor in drilling costs, and the regional distribution and the average depths for the lower-48 have varied over time, we also tried to normalize for region and depth. After examination of the JAS drilling cost data, we selected West Texas wells (Districts 7C, 8, and 8A) for a second series of analyses. While there has still been some variability in well depth in this region, it is less than for the entire lower-48. In addition, use of data for a single region minimizes the impacts on costs from shifts among regional drilling provinces that may affect the lower-48 data. With the exception of oil and gas prices, we translated all independent variables in the model to a West Texas, Permian Basin, or Texas-specific indicator, as appropriate and available. It was expected that the statistical fit of the West Texas well cost series of models would be better than their lower-48 well counterparts.

Preliminary Results – Lower-48 Model. Our preliminary model results show an underlying trend in lower-48 drilling costs that was increasing over time at about 0.5 percent per year. When the various components of drilling costs for an average lower-48 well were removed, this increasing cost trend remained in all cases.

Preliminary Results – West Texas Model. When this preliminary model was applied specifically to West Texas, to attempt to account for the variation in drilling costs attributable to changing depths and regional distribution of wells, we found that the underlying cost trend was decreasing over the 1970 to 1989 time period. However, the statistical fit to these data was worse than that for the model applied to the total lower-48. Moreover, several coefficients in the West Texas model changed sign, compared to the lower-48 model, resulting in a counter-intuitive representation of costs.

One explanation of this phenomenon, we believe, relates to one of the basic premises upon which the model is based. The supply equation for rigs assumes basically a closed system in that if insufficient rigs are available to satisfy the demand for drilling, more rigs are built, with correspondingly higher drilling costs. In a specific region, if insufficient rigs in the region are available, then either new rigs are built, or new rigs from another region come in. Consequently, increased demand for drilling may not necessarily result in increased costs.

Recent Methodological Improvements

At the July 24 Work Group meeting, a number of suggestions were made concerning ways to potentially improve the representation of historical drilling costs and the underlying trend in these costs (if any exists) over the last two decades. In response to these suggestions, the following modifications to the representation of drilling costs were attempted:

- First, drilling data for Appalachian and some Midcontinent states were removed from the data base used for the analyses of the lower-48 data. (For purposes of this statistical analysis, the states removed were Pennsylvania, West Virginia, New York, Ohio, Kentucky, Illinois, Indiana, and Michigan). These states were removed because they are associated with predominantly shallow, low-pressure wells, drilled, to a large extent, by truck-mounted or cable tool rigs. These rigs are not included in the traditional rig-count statistics, and no other source which accurately tracks these rigs exists. Moreover, these rigs often drill wells for purposes other than for oil and gas production.
- Second, a lag (for one year) in the available rigs term in the supply of drilling equation was added.
- Third, the drilling cost data for the 1970 to 1973 time period was not considered in the statistical regression.
- Fourth, a term representing annual wellhead revenues per active rig was added to the rig-supply equation.

Drilling Costs Results for Improved Methodology

In general, the regressions results for these representations were consistently better than those obtained from the previous representation, for each of the different characterizations of drilling costs. For nearly all formulations, the R^2 statistics for all three equations were very good (greater than 0.9), and the t-statistics for the defined independent variables were all significant with 95 percent confidence. Finally, the coefficients for all the model variables had the "right" sign, i.e., they all behaved in conceptually satisfying ways. (A summary of parameters characterizing the statistical validity of the regression results is presented in Appendix 1 of this memorandum.) However, some representations were better than others, as summarized below:

- The representation of the supply of drilling equation with a one-year lag in the term for total available rigs, using the data set excluding Appalachian and Midcontinent wells, provided a better statistical fit, primarily due to better t-statistics, than the version with no lag in the supply of drilling equation.
- The best characterization of drilling costs appears to be total drilling costs less completion and equipment costs, supervision and overhead costs, and depreciation and rig-maintenance costs. (This formulation had good R^2 values for all regression equations and the best t-statistics for the independent variables.)
- Restricting the analysis to the 1974-1989 time period (i.e., excluding the data for the years 1970 to 1973) resulted in a worse statistical fit, and the t-statistics for some independent variables became insignificant.
- Adding a term for wellhead revenues per active rig in the rig-supply equation did not result in a statistically superior representation of drilling costs.

Thus, the final model consisted of data representing well cost data consistent with the rig count statistics upon which it was based (i.e., with wells in Appalachia and the Midcontinent excluded from the analysis). Moreover, those components of well drilling that fundamentally changed over the two decade period of evaluation (completions, overhead, and depreciation) were excluded from the historical cost analyses. This representation gave stable, relatively consistent results for most model formulations.

The final three-equation model for drilling costs is represented as follows:

Demand for Drilling:

LQ = CD + BD*LPD + B_OIL*LPO + B_GAS*LPG + FINDRATE*LWRA + OIL_PROD*LOPER

Supply of Drilling:

LPD = CS + BS*LQ +BS_RIG*LRIGAV + B_DEPTH*SQRDEPTH + TREND*TIME + B_WAGE*LHWAGE

Supply of Rigs:

LRIGAV = CR + BR_LAG*LRIGAVG + BR_PD*LPDG

where

LQ = Loge (supply of drilling)
LPD = Loge (price of drilling)
LRIGAV = Loge (number of available rigs)
LPO = Loge (price of oil)
LPG = Loge (price of gas)
LWRA = Loge (price*reserve additions for oil & gas/total wells)
LOPER = Loge (oil production per well)
SQRDEPTH= Square root of average depth of all wells drilled
TIME = Number of years since 1969
LHWAGE = Loge (hourly wage of all oil & gas extraction workers)
LRIGAVG = Lag LRIGAV by a year
LPDG = Lag LPD by a year

(Note: The other remaining variables are regression coefficients.)

The statistical results for this case are summarized in Table 2.

Underlying Trend in Drilling Costs

For all formulations, a time trend term was included in the regression to determine whether a trend in costs over time, after accounting for the effect of the independent variables was present, and if so, the nature and magnitude of this trend. In all cases, a statistically significant trend term (measured by the t-statistic for this term) was present. *This trend term represented a long-term decrease* *in cost ranging from 2.5 percent to 3.6 percent per year. In most cases, including the model determined to be the best, the trend in drilling costs was about a 2.8 percent per year decrease over the two-decade time period, as shown in Figure 1.*

Finally, we attempted to determine whether this underlying trend in drilling costs was different in the 1970s compared to the 1980s. Unfortunately, this comparison was not statistically compelling, i.e., we did not have results of adequate statistical significance to distinguish the difference between cost trends in the 1970s and those trends in the 1980s. At first glance, the results show that over the 1980s, drilling costs decreased at a rate of about 2.8 percent per year. In the 1970s, on the other hand, the statistical results seem to indicate that costs *increased* over the decade at less than 1 percent per year. However, given the small number of data points used for determining this regression, the statistical results for each individual decade were not as satisfying. Moreover, the signs of some coefficients changed for the single-decade data set, relative to the original two-decade model. Finally, the t-statistics for certain independent variables in the single-decade cases became insignificant when the smaller data sets were used.

Other Cost Categories

Exploration Costs

Exploration costs, for purposes of this analysis, were defined to include the geological and geophysical expenditures category reported in the API Survey of Oil and Gas Expenditures (and its predecessor Bureau of Census reports). These costs were represented two ways:

- Geological and geophysical (G&G) expenditures per successful wildcat well drilled
- Geological and geophysical expenditures per seismic crew-month worked.

Like drilling, non-drilling-related G&G costs represent essentially a captive market. Consequently, a multiple equation, market equilibrium model for representing historical costs, with a functional form similar to that for the drilling model, was investigated. However, several limitations to this approach exist for G&G costs, which did not exist for drilling. First, historical G&G expenditures are not directly related to any infrastructure indicator, like rig supplies are to drilling costs. Therefore, the supply equation cannot be as easily represented by a stock flow type model, like that used in the drilling cost model discussed above.

In addition, the quality of data for drilling costs and the variables influencing costs are significantly better than that associated with G&G expenditures. Moreover, data on drilling costs have been collected for a significantly longer period of time. The drilling cost data were analyzed over the 1970 to 1989 time period, while G&G expenditure data could only be analyzed over the 1973 to 1989 time period.

Therefore, given all these factors and the constraints on time and budget for this effort, it was determined that a single equation model for G&G costs was more appropriate for purposes of this study.

Of the two representations of G&G costs investigated, the best statistical results were obtained using G&G expenditures per new field wildcat well drilled. Numerous possible independent variables potentially influencing G&G costs were assessed, alone and in various combinations. From this, the best statistical representation of historical G&G costs was determined to be a function of crude oil price and the number of producing oil wells in the lower-48. This model resulted in a R^2 value of 0.94 for the regression, with both independent variables showing high t-statistics. These statistical results are presented in Table 3, and are shown graphically in Figure 2.

However, when a trend term was added to this regression equation, this variable was determined to be insignificant, as indicated by a low t-statistic value. This is because the number of producing wells was correlated with time, i.e., there was high colinearity between the two defined independent variables.

As an alternative representation, G&G expenditures per wildcat well drilled was analyzed as a function of only oil price and time. Under this model, both the price and time independent variables were significant (high t-statistic values) but the regression resulted in a lower R^2 value than that obtained with price and number of oil wells as the independent variables. Moreover, the time trend in this formulation was positive, indicating that G&G costs, minus all other influences on costs, were tending to increase over time (at about 5 percent per year, on average).

Therefore, the results of this analysis show that no clear downward trend in exploration costs for oil and gas can be determined from the available data on G&G expenditures and the likely parameters influencing these costs.

Lease Equipment Costs

In the analysis of drilling costs, completion and well equipment costs were removed from the drilling cost data in order to arrive at a representation of drilling costs that remained relatively consistent with time. The only publicly available representation of completion costs is the IPAA data, which represent completion and well equipment costs only as a fraction of total drilling costs, estimated every five years. In theory, completion costs over time can be estimated be multiplying the annual JAS cost data on total drilling, completion, and well equipment costs by the IPAA estimate of the portion of these costs associated with completions. However, this representation stretches the bounds of credibility, with the potential for many inaccuracies and misrepresentation introduced to the data series. Given these concerns, completion and well equipment costs were not assessed separately in this analysis.

However, the Energy Information Administration (EIA) does publish annual cost data on domestic oil and gas lease equipment in its annual report entitled *Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations*. The costs published in this annual report are based on specified, hypothetical leases. Typical gas leases are characterized for specific regions, well depths, and average production rates. The specifications for these typical leases are developed by EIA staff engineers, assuming one gas well per typical lease. This definition has remained fairly consistent over time, with the data series dating back to 1978. The design criteria are based on the predominant methods of operation for each area represented, with the individual items of equipment costed using price lists and communication with equipment manufacturers.

For example, the basic equipment requirements assumed for a typical gas lease in West Texas producing gas at a rate of 1 MMCF/day from a 12,000 foot well are shown in Table 4. For a typical lease, equipment costs are reported by the following cost categories: flowlines and connections, production package, storage tanks, and dehydrators. To minimize regional diversity in lease equipment costs, the analyses were performed on composite (all cost categories) gas lease equipment costs for a 4,000-foot gas well in West Texas producing 250 MCF/day, with requirements similar to that listed in Table 4.

Gas lease equipment costs were assessed as a function of numerous possible independent variables, alone and in various combinations, assuming a single equation model. From this, the best statistical representation of historical gas lease equipment costs was determined to be a function of crude oil price (average U.S. wellhead price) and the number of producing gas wells in Texas. This model resulted in a R^2 value of 0.92 for the regression; the results of which are presented in Table 5.

For this model, when time is included in the regression (i.e., the trend term in included in the statistical analysis), there is no significant trend indicated. However, where lease equipment costs are determined as a function of oil price only (assuming that the number of producing gas wells is correlated with time), the trend term becomes statistically significant. Under this formulation, however, costs appear to *increase* at a rate of about 2.7 percent per year, as shown in Figure 3.

One should note, however, that these costs included those incurred to comply with environmental regulations, which have become increasingly stringent over time, as discussed in more detail below. The data series contain insufficient information to accurately distinguish the expenditures for environmental control equipment relative to other gas lease equipment. However, if these costs are excluded from consideration, gas lease equipment costs could in fact decrease over time (to be discussed in more detail below).

Operation and Maintenance Costs

The EIA also publishes cost data on annual operating costs for domestic oil and gas leases in its annual report discussed above. Like that for equipment costs, the costs published in this annual report are based on specified, hypothetical leases, disaggregated by region, well depth, and average production rate.

For a typical gas lease, annual operating are reported by the following cost categories: direct labor and overhead; fuel, chemicals, and disposal; surface maintenance; and subsurface maintenance. To minimize regional diversity and be consistent with the analyses of lease equipment costs, the analyses were performed on composite annual gas lease operating costs for a 4,000-foot gas well in West Texas producing 250 MCF/day.

Annual gas well operating costs were assessed as a function of numerous possible independent variables, alone and in various combinations, also assuming a single equation model. The best statistical representation of historical annual operating costs for gas wells was determined to be a function of crude oil price (West Texas Intermediate), average hourly earnings for oil and gas field service workers, and time. This model resulted in a R^2 value of 0.95. The results of this regression analysis are presented in Table 6. Under this formulation, however, when the influences of hourly earnings and oil prices are removed from consideration, costs appear to *increase* at a rate of about 6 percent per year, as shown in Figure 4.

Environmental Compliance Costs

Expenditures for pollution abatement and for achieving environmental compliance in the domestic E&P industry have increased significantly over the last twenty years. However, all of the cost categories which were analyzed above to determine whether distinguishable trends in costs over the last two decades exist were assessed without explicitly taking into account environmental compliance expenditures. To obtain a more accurate representation of the pure role of technology on the costs of natural gas E&P, these environmental compliance costs should be accounted for in the analysis.

Unfortunately, no good data series exists to analytically separate environmental compliance costs from the remainder of the costs associated with natural gas exploration, development, and production. Therefore, it is impossible to statistically remove environmental compliance costs from the regression analyses performed for the various cost categories analyzed. However, some proxies for environmental costs do exist. While these costs cannot be analyzed in context with the other cost categories assessed, an understanding of these sources for environmental expenditures in the domestic oil and gas industry can shed some light on the role of environmental compliance requirements on the evolution of costs in this industry.

One such source of data was developed by the API in a survey on environmental expenditures of the petroleum industry. The report summarizes environmental expenditures for air, water, land, and other programs. Expenditures are categorized as capital; administrative, operating, and maintenance; and research and development. Expenditures were tabulated by industry sector — exploration and production (E&P), transportation, marketing, and manufacturing. The API conducted this survey over the 1975 to 1984 time period.

For purposes of this analysis, environmental expenditures in the E&P sector were analyzed separately in terms of capital expenditures and administrative, operating, and maintenance expenditures. These expenditures were normalized to constant 1982 dollars, and to the number of producing wells per year. These results are summarized in Table 7. As shown, capital expenditures for environmental compliance by the E&P industry over this time period grew at an average rate of about 3 percent per year. Expenditures for administrative, operating, and maintenance grew at an average rate of about 6 percent per year. In total, environmental expenditures in the E&P industry, excluding those for research and development, grew at a rate of about 4 percent per year over the 1975 to 1984 time period.

Another annual survey of environmental expenditures appears in the Survey of Current Business. This survey does not separate expenditures by industry, so the domestic oil and gas industry is not assessed specifically. However, this survey shows that over the 1972 to 1983 time period, expenditures (in real dollars) for pollution abatement and control increased at an average annual rate of about 4.5 percent per year. Expenditures over the 1970s increased at a higher rate, averaging about 5 percent per year, while in the 1980s, environmental expenditures, according to this survey, increased at an average rate of about 4 percent per year.

Conclusion

The following conclusions relating to the role of technology on natural gas exploration, development, and production costs can be drawn from this analysis:

- For drilling costs, when shallow drilling in the Appalachian and Midcontinent regions are excluded from the regression analyses, long-term drilling costs appear to have decreased at a rate of about 2.8 percent per year over the last twenty years, when the other influences of drilling costs (oil prices, rig availability, well depths, etc.) remain constant.
- For exploration costs, the results of this analysis show that no clear trend in exploration costs for oil and gas can be determined from the available data on G&G expenditures and the likely parameters influencing these costs.
- For lease equipment costs, where these costs are determined as a function of oil price only (assuming that the number of producing gas wells is correlated with time), these costs appear to *increase* at a rate of about 2.7 percent per year. However, over this period, capital expenditures associated with environmental requirements in the E&P industry increased on the order of 3 percent per year. If environmental costs are accounted for, long term costs for lease equipment, accounting for the fluctuations due to price and the increases associated with environmental compliance, have remained approximately constant over the last 15 years.
- For annual operating and maintenance costs, the best statistical representation of historical annual operating costs for gas wells was determined to be a function of crude oil prices, average hourly earnings for oil and gas extraction workers, and time. Under this formulation, when the influences of hourly earnings and oil prices are removed from consideration costs appear to *increase* at a rate of about 6 percent per year. However, according to API, expenditures for administrative, operating, and maintenance in the E&P industry grew at an average rate of about 6 percent per year. Accounting for this, the long-term trend in annual operating and maintenance costs appears to be relatively constant, or perhaps slightly decreasing.

Table 1

Distribution of Expenditures for Drilling and Completing U.S. Wells

		Percent of Total Expenditures		Cost Index 1989=100
		1974	**1989**	**1974**
Well Costs				
Casing Hardware		0.7	0.9	36.9
Casing & Tubing		17.5	13.7	36.9
Cement & Cementing		3.7	4.8	48.8
Drill Bits & Reamers		1.6	2.3	31.5
Drilling Mud & Additives		6.9	5.8	51.6
Payments to Drill Contractors		36.6	30.7	66.9
Road & Site Preparation		4.1	4.4	41.1
Special Tool Rentals		3.1	2.7	44.4
Transportation		3.9	2.4	55.2
Subtotal		78.1	67.7	
Completion and Equipment				
Directional Drilling Services	1	0.6	1.6	37.4
Formation Treating	1	3.0	4.4	53.4
Misc. Equipment & Supplies	1	2.0	3.0	35.1
Perforate	1	1.1	1.4	20.6
Plugging	1	0.5	1.3	45.2
Wellhead Equipment	1	1.6	1.8	30.9
Subtotal		8.8	13.5	
Fuel	2	1.1	0.6	40.5
Well Services				
All Other Physical Tests	3	0.7	0.6	26.4
Logging & Monitoring Systems	3	1.2	1.1	31.8
Logs & Wireline Evaluation	3	3.2	3.7	42.2
Subtotal		5.1	5.4	
Supervision & Overhead	4	2.1	5.6	39.2
Other Expenditures	5	4.6	7.1	44.1

Note: See following page for description of the categories of drilling costs.

Table 2

Statistical Results from Drilling Cost Analyses

NonLinear 3SLS Summary of Residual Errors

Equation	DF Model	DF Error	SSE	MSE	Root MSE	R-Square	Adj R-Square
Demand for Drilling	6	14	0.07878	0.0056274	0.07502	0.9751	0.9663
Supply of Drilling	3	17	0.08825	0.0051914	0.07205	0.9698	0.9662
Supply of Rigs	6	14	0.06639	0.0047419	0.06886	0.9464	0.9272

NonLinear 3SLS Paramter Estimates

Parameter (Coefficient)	Estimate	Approx. Std Err	'T' Ratio	Approx. Prob> |T|
Oil Price	0.479524	0.08568	5.60	0.0001
Lag Rigs	0.708344	0.05340	13.26	0.0001
Trend	-0.032128	0.0091941	-3.49	0.0036
Gas Price	0.705678	0.11650	6.06	0.0001
Findrate	0.301175	0.13479	2.23	0.0423
Oil-Prod	1.669384	0.21314	7.83	0.0001
Drilling Price	-0.343610	0.13926	-2.47	0.0271
Well Depth	0.067004	0.01698	3.95	0.0015
Rig Supply	-0.254713	0.10080	-2.53	0.0242
Wage Rate	5.430871	0.95995	5.66	0.0001
Constant for Drilling Quantity	-6.813793	2.23104	-3.05	0.0086
Drilling Quantity	0.335700	0.10169	3.30	0.0052
Constant for Drilling Price	3.491477	1.03933	3.36	0.0047
Constant for Rig Supply	-4.087867	0.80035	-5.11	0.0001
Lag Drilling Price	0.512584	0.07998	6.41	0.0001

Number of Observations

Used	20
Missing	2

Statistics for System

Objective	1.1291
Objective*N	22.5816

Table 3

Statistical Results from Exploration Costs Analyses

Dependent Variable: G&G Expenditures per New Field Wildcat Well

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Prob>F
Model	2	171188364033	85594182016	111.585	0.0001
Error	14	10739107945	767079138.91		
C Total	16	181927471977			

Root MSE	27696.19358	R-Square	0.9410
Dep Mean	340844.22945	Adj R-Square	0.9325
C.V.	8.12576		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	T for HO: Parameter = 0	Prob > |T|	Variance Inflation
Intercept	1	-590653	72459.135728	-8.152	0.0001	0.00000000
Oil Price	1	5339.788749	840.31353934	6.355	0.0001	1.10859150
Prod. Oil Wells	1	1.457730	0.13432937	10.852	0.0001	1.10859150

Correlation of Estimates

Corrb	Intercept	Oil Price	Prod. Oil Wells
Intercept	1.0000	0.0873	-0.9693
Oil Price	0.0873	1.0000	-0.3130
Prod. Oil Wells	-0.9693	-0.3130	1.0000

Durbin-Watson D	1.827
(For Number of Obs.)	17
1st Order Autocorrelation	0.077

Table 4

Detailed Lease Equipment List for 12,000-Foot Gas Wells in West Texas Producing 1 Million Cubic Feet per Day

---

Safety Valve

Size: 2 inches
Working pressure: 10,000 pounds per square inch
Actuates: High/low pressures

Production Package

Choke: Built in, inlet
Coils: 2 inches XH
Heater Rating: 250,000 BTU per hour
Size: 16 inches by 8 feet
Working pressure: 1,000 pounds per square inch

Dehydrator/Reconcentrator

Type: Glycol Absorption
Size: 12¾ inches
Working pressure: 1,440 pounds per square inch

Storage Tanks (2)

Size: 10 feet x 15 feet
Capacity: 210 barrels
Construction: Welded Steel

Source: Energy Information Administration, Office of Oil and Gas.

Table 5

Statistical Results for Analysis of Lease Equipment Costs

Dependent Variable: West Texas Composite Lease Equipment Cost

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Prob>F
Model	2	141647902.00	70823951.000	45.754	0.0001
Error	8	12383341.444	1547917.6804		
C Total	10	154031243.44			

Root MSE	1244.15340	R-Square	0.9196
Dep Mean	42832.43891	Adj R-Square	0.8995
C.V.	2.90470		

Parameter Estimates

Variable	DF	Parameter Estimate	Standard Error	T for HO: Parameter = 0	Prob > |T|	Variance Inflation
Intercept	1	10134	3481.5661717	2.911	0.0196	0.00000000
Oil Price	1	162.261278	43.52854463	3.728	0.0058	1.00417574
Prod. Gas Wells TX	1	0.685404	0.08015382	8.551	0.0001	1.00417574

Correlation of Estimates

Corrb	Intercept	Oil Price	Prod. Gas Wells TX
Intercept	1.0000	-0.2385	-0.9478
Oil Price	-0.2385	1.0000	-0.0645
Prod. Gas Wells TX	-0.9478	-0.0645	1.000

Durbin-Watson D	1.878
(For Number of Obs.)	11
1st Order Autocorrelation	0.014

Table 6

Results of Statistical Analysis for Annual Operating and Maintenance Costs

Dependent Variable: West Texas Composite Operating Cost

Analysis of Variance					
Source	**DF**	**Sum of Squares**	**Mean Square**	**F Value**	**Prob>F**
Model	3	100352880.19	33450960.062	47.571	0.0001
Error	8	5625493.1473	703186.64342		
C Total	11	105978373.33			

Root MSE	838.56225	R-Square	0.9469
Dep Mean	20460.81727	Adj R-Square	0.9270
C.V.	4.09838		

Parameter Estimates						
Variable	**DF**	**Parameter Estimate**	**Standard Error**	**T for HO: Parameter = 0**	**Prob > |T|**	**Variance Inflation**
Intercept	1	-26037	11093.303403	-2.347	0.0469	0.00000000
Hourly Wage	1	3268.526668	1018.5691504	3.209	0.0124	5.97224933
WTI Price	1	27.497439	48.47080728	0.567	0.5861	4.48723372
Time	1	1205.098243	107.93493125	11.165	0.0001	2.36913311

Correlation of Estimates				
Corrb	**Intercept**	**Hourly Wage**	**WTI Price**	**Time**
Intercept	1.0000	-0.9918	0.6953	-0.5902
Hourly Wage	-0.9918	1.0000	-0.7769	0.4992
WTI Price	0.6953	-0.7769	1.0000	-0.0269
Time	-0.5902	0.4992	-0.0269	1.0000

Durbin-Watson D	1.216
(For Number of Obs.)	12
1st Order Autocorrelation	0.344

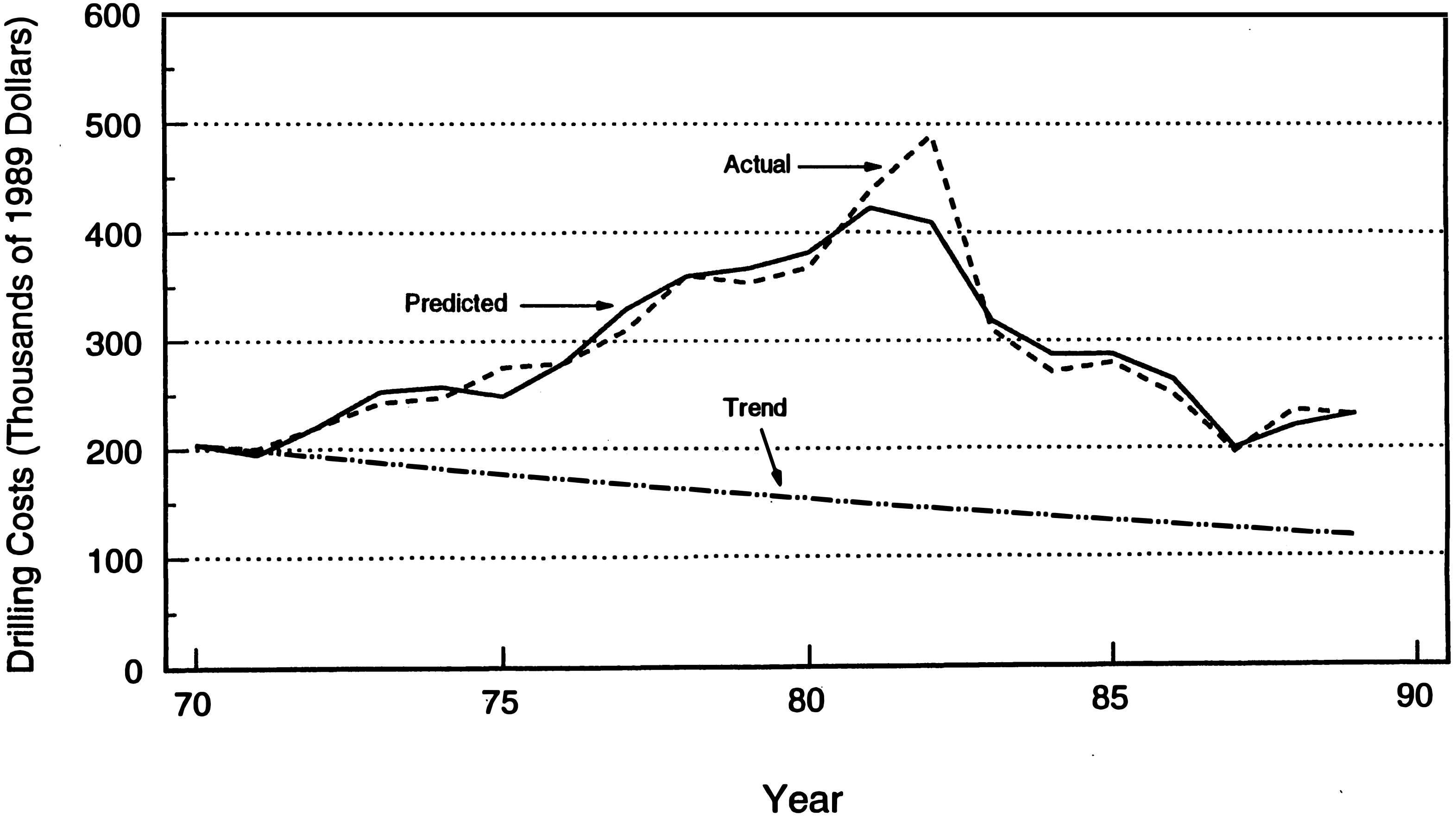
Table 7

Results of API Survey of Environmental Expenditures of the Exploration and Production Sector

Year	Capital Million $	Operating Million $	PPI 1982=100	Producing Wells	Capital Mill 82$	Capital Per Well 82$	% chg	Operating Mill 82$	Operating Per Well 82$	% chg	Tot Capital & Oper Mill 82$	Tot Capital & Oper Per Well 82$	% chg
1975	233	136	59.41	638304	392.2	614.42		228.9	358.63		621.1	973.06	
1976	290	163	43.07	640810	673.3	1050.74	71.0%	378.5	590.59	64.7%	1051.8	1641.32	68.7%
1977	309	200	67.40	355998	458.5	1287.81	22.6%	296.7	833.53	41.1%	755.2	2121.34	29.2%
1978	324	224	73.43	673692	441.2	654.95	-49.1%	305.1	452.81	-45.7%	746.3	1107.76	-47.8%
1979	358	244	81.33	696746	440.2	631.77	-3.5%	300.0	430.59	-4.9%	740.2	1062.36	-4.1%
1980	559	329	90.12	725514	620.3	854.96	35.3%	365.1	503.19	16.9%	985.4	1358.14	27.8%
1981	964	568	96.71	755848	996.8	1318.78	54.3%	587.3	777.04	54.4%	1584.1	2095.81	54.3%
1982	934	553	100.00	790895	934.0	1180.94	-10.5%	553.0	699.21	-10.0%	1487.0	1880.15	-10.3%
1983	621	532	102.77	825242	604.3	732.22	-38.0%	517.7	627.28	-10.3%	1121.9	1359.51	-27.7%
1984	723	560	105.21	854660	687.2	804.06	9.8%	532.3	622.78	-0.7%	1219.5	1426.84	5.0%
Average							10.2%			11.7%			10.6%
Growth Rate							3.0%			6.3%			4.3%

Figure 1

Lower-48* Drilling Costs Per Well



* Excluding Illinois, Indiana, Kentucky, Michigan,
New York, Ohio, Pennsylvania, and West Virginia

Figure 2

Geological and Geophysical Expenditures Per New Field Wildcat Well

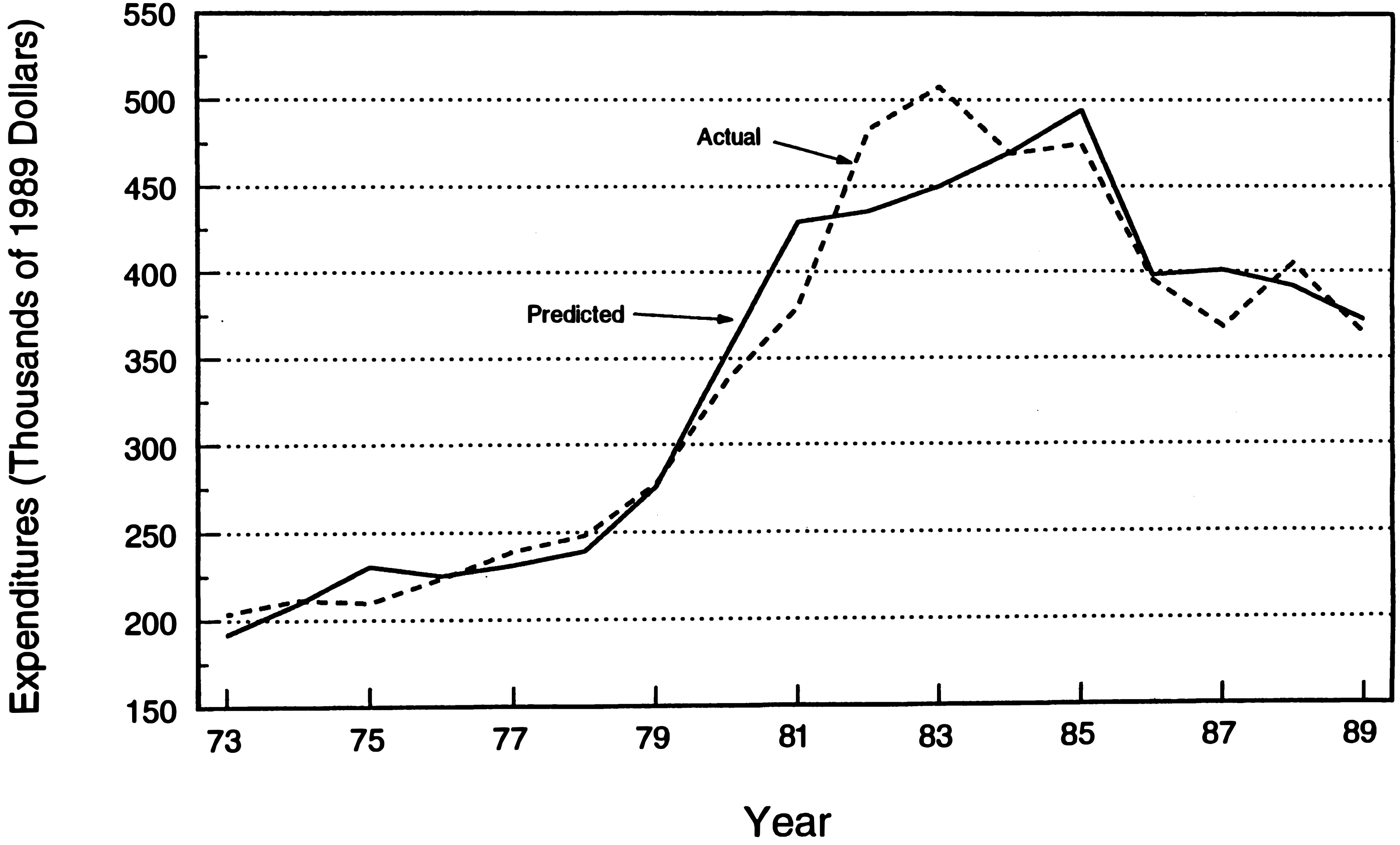


Figure 3

West Texas Lease Equipment Costs
(4,000 ft. Gas Well Producing 250 Mcf/day)

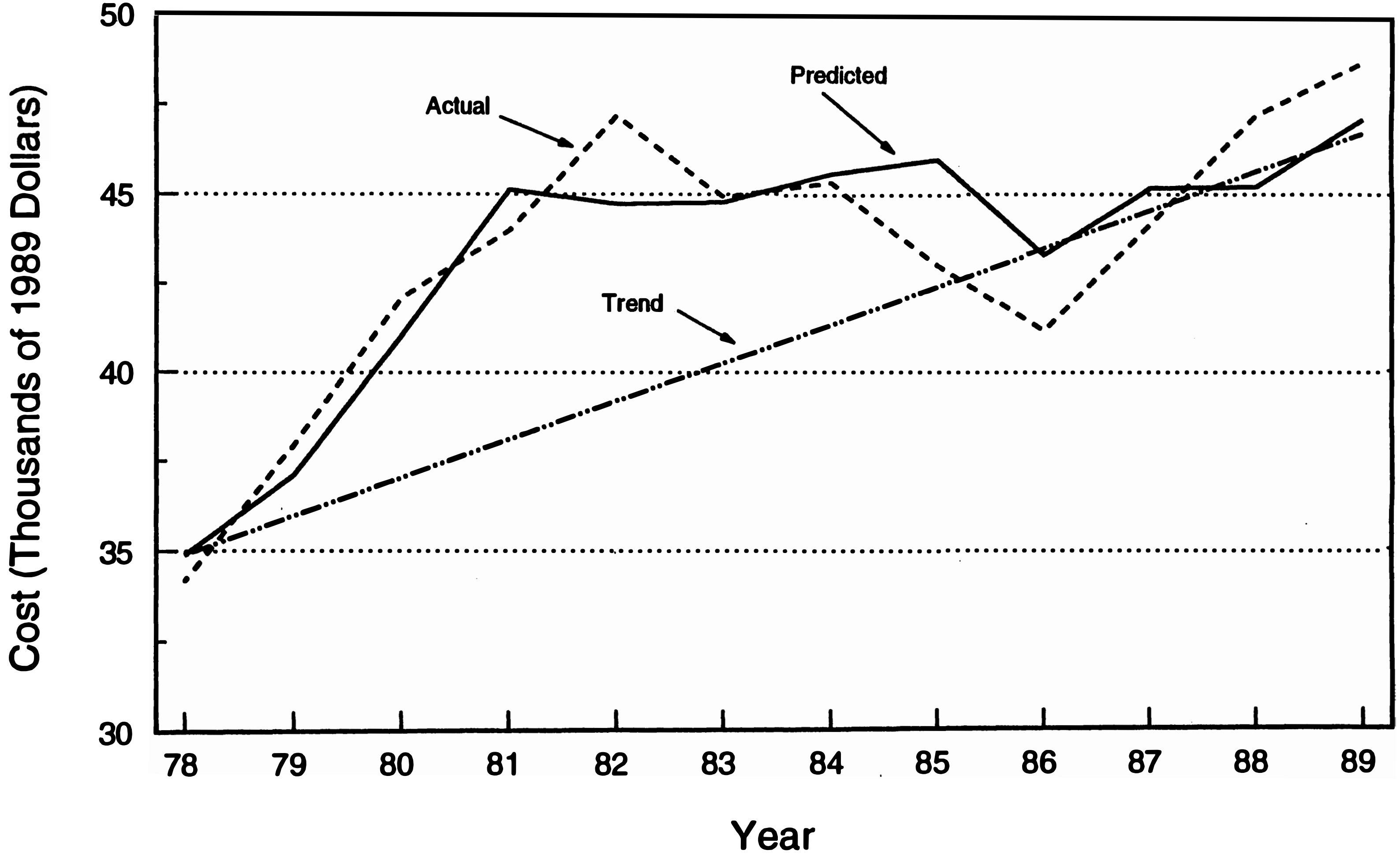
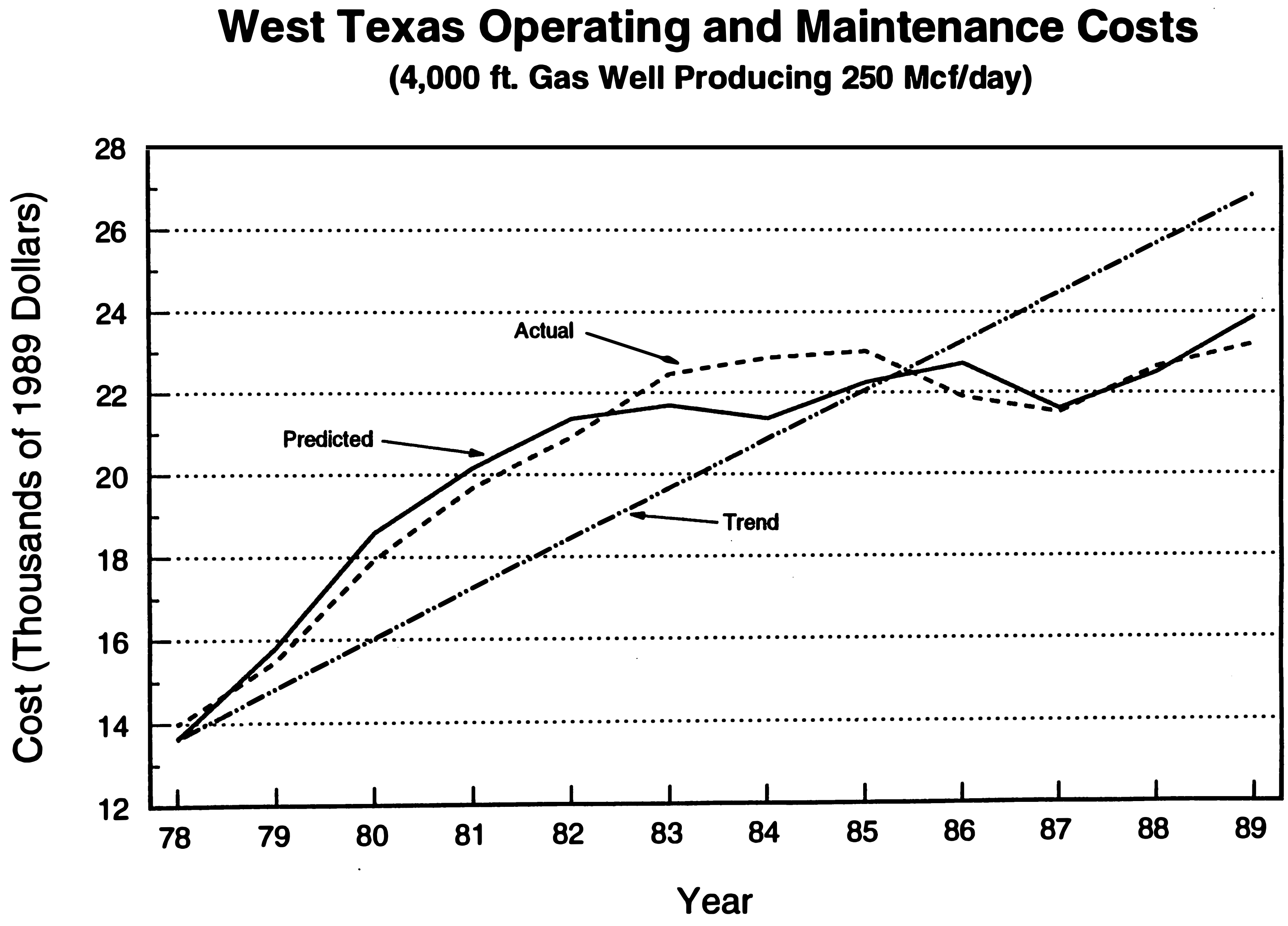


Figure 4



West Texas Operating and Maintenance Costs
(4,000 ft. Gas Well Producing 250 Mcf/day)

APPENDIX 1 TO ICF RESOURCES MEMORANDUM

Interpretation of Statistical Regression Results

The discussion below briefly summarizes the key statistical parameters used in this analysis for determining the validity and acceptability of proposed statistical regressions.

- **R-squared.** The value of R^2 is an indicator of how much of the variation in the data is explained by the model or what proportion of the total variation in the response data is explained by the fitted regression model. The value is the sum of squares for the model divided by the sum of squares of the actual data. What are determined to be acceptable values for R^2 varies by application. For example, a social scientist might consider an R^2 of 0.3 to be acceptable, while a physicist might consider 0.98 to be small. With an increasing number of completely unrelated regressors or variables, the sum of squares increases and thus improves the value of R^2. However, if the number of variables is close to the number of observations, the value for R^2 becomes misleading and the adjusted R^2 is considered to be a better indicator. The use of unimportant variables can reduce the effectiveness of the prediction by increasing the variance of the estimated response.
- **t-statistic.** The t-statistic is the parameter estimate divided by the standard deviation of its values. A t-statistic for a particular variable indicates the significance of that variable to the model and the term "prob > |T|" indicates a chance that a t-statistic would obtain a larger absolute value than that observed given that the true parameter is 0. A low t-statistic indicates that the variable does not differ significantly from zero, and hence, justifies removing that variable from the model. A t-statistic of greater than 2, indicating more than 95 percent confidence in the variable's significance, justifies retaining a variable in the model. For the prob> |T|, a small value is desirable. A value of 0.0001 indicates that there is only a 0.01 percent probability that this result could have been obtained by chance.
- **F-statistic.** The value of the F-statistic gives an indication of the overall significance of the model. In this case, the exploration cost model with an F value of 111.585 and corresponding "Prob>F" of 0.0001 has a 99.99 percent confidence level that the explanatory variables are significant.

The parameter estimates, including the intercept parameter, indicate the degrees of the relationship between the dependent variable and the independent variables. A model with a good statistical fit (a high value for R^2) may have to be rejected, however, if the results are nonsensical. In addition to statistical validity, the predictive algorithms are selected on the basis of the relationship that might be expected from the variables considered. If unreasonable or illogical relationships result, a model with a good statistical fit should still be rejected. In this study, all parameter estimates were tested to ensure that any changes in their values have reasonable effects on dependent variables, and that the model explains the data over all ranges and combinations of variables conceivable.

APPENDIX J
EXAMPLE SPECIFIC TECHNOLOGIES

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CROSS-WELL TOMOGRAPHY—EXPLORATION

Purpose:

The main purpose for cross-well tomography is reservoir characterization and delineation of reservoir boundaries. The target resolution for reservoir bed thickness is about 10 feet. Improved accuracy in interwell rock properties measurement will be obtained in the following areas: fluid lithology, rock velocity, porosity, and saturation and possibly, permeability.

How:

The recent emergence of cross-well technology is based on the premise that a downhole, high frequency measurement can bridge the gap in resolution and coverage between geophysical wireline logs and conventional surface-based seismology. The technique involves placement of a seismic source in a downhole location and the emission of high frequency, broadband energy from that source. Seismic receiver arrays, also in a downhole location in a nearby well, receive the energy that is propagated through the rock between wells. Since the travel path of the seismic energy that is picked up by the downhole receivers does not include the near-surface weathering layer which can have significant high-frequency seismic attenuation, a much broader and higher range of frequencies can be recorded. Higher frequencies correlate to higher resolution. The resolution capability of cross-well should be on the order of one magnitude better than conventional surface seismic data.

1975 Technology:

There was little or no research being done in cross-well tomography at this time. Tomography had been developed in the medical field before being performed using seismic data.

1990 Technology:

Until recently, cross-well techniques used in gas and oil applications had not received much attention primarily because safe and reliable downhole sources for use in deep sedimentary environments did not exist. Also, cross-well tomography is expected to operate at frequencies of 500–1,000 Hz at nominal production well spacings. Although not commercially available today, the technology for data acquisition, processing, and interpretation do exist within a number of industry research labs and industry groups. The most widely used source for deep applications and close well spacings (<1,000 feet) is the piezo-electric source, while the air gun is the most popular for shallow applications with large well spacings (>1,000 feet) or poorly consolidated formations. Missing is a deep well source for large well spacings. During the early-90s, the piezo-electric fluid-coupled vibrator and the hydraulic wall-clamped vibrator have emerged as leading candidates for more versatile applications for the coming decade.

New processing techniques for the coming five years include full-waveform reflection and diffraction processing, where high resolution images are produced from targets near and below well TD. Encouraging work in combining cross-well images with surface seismic, well logs, core and production data are emerging and will expand in the near future.

Future Technology:

With the emergence of improved downhole sources and the development of appropriate processing/pre-processing algorithms, imaging techniques, and interpretation techniques, cross-hole tomography will be used in assisting detailed (5–10 feet) reservoir characterization and monitoring at one mile well spacings. To obtain this kind of resolution, recorded frequencies on the order of 2 KHz is required. There is also great potential in combining this technology with 3-component seismic and 3-D seismic imaging for exploration and development of hydrocarbons.

Result:

The oil and gas industry is heading toward a more integrated approach to reservoir development and exploration. Cross-well tomography offers the advantage of imaging the inter-well reservoir information in much more detail than state-of-the-art surface seismic or even offset vertical seismic profiles (VSP).

Where:

Recent tomography field experiments have been done in south and west Texas, and in California. Much of work to date has focused on application to enhanced oil recovery steam flood projects. Future work will include regions of more diverse and complex geological regimes.

Technology References:

Journal of Geophysical Research, "Determination of the three-dimensional seismic structures of the lithosphere," K. Aki, A. Christoffersson, and E. S. Husebye, vol. 82, pp. 277–296, 1976.

Bulletin of the Seismological Society of America, "Crosshole tomography for variable media," G. McMechan, J. M. Harris, and L. Anderson, vol. 77, pp. 1945–1960, 1987.

Conference Proceedings, SEG Annual International Convention, "High frequency cross-well seismic measurements in sedimentary rocks," J. M. Harris, pp. 147–150, 1988.

Geophysics: The Leading Edge, "Acoustic tomography for monitoring enhanced oil recovery," J. H. Justice, vol. 8, pp. 12–24, 1989.

Geophysics, "Traveltime tomography: A comparison of popular methods," W. S. Phillips and M. C. Fehler, vol. 56, pp. 1639–1649, 1991.

LOGGING TOOLS

Purpose:

To evaluate wells for lithology, porosity, fluid content, and bedding dip.

How:

Various measurements are made at the end of a logging cable to evaluate a well. The measurements are made with sophisticated sensors that detect voltages, currents, magnetism, gamma rays, neutrons, sound, and hole size. These tools are powered by a cable that contains one to seven conductors and are controlled by electronics at the surface. The cable is lowered down the hole and measurements are plotted as a function of depth on a log as they pass the rocks in question. Gamma ray and spontaneous potential logs are used for determining clean sands. Density, neutron, and sonic logs are used for porosity. Resistivity logs are used for determining water saturations. High resolution micro resistivity logs are run on multiple arms for correlation and determination of bedding dip.

1975 Technology:

The density-neutron-gamma ray resistivity combination was typically run at this time. Sonic logs were sometimes run in place of density-neutron logs for porosity and sometimes in addition for correlation with seismic sections. The surface recording equipment was typically analog. Dipmeter traces often had to be correlated by hand. Micro logs were still often run for determining porous, permeable sands.

1990 Technology:

Density-neutron-gamma ray-resistivity combinations are still the typically run logging suites. However, most tools have digital data transmission and surface equipment. The digital recording of data allows immediate analysis of the data at the well sight and immediate transmission of the data to operator offices. Better processing of the raw data measurements result in improved accuracy and better bed resolution. More sensors are being placed on many logs such as sonic logs with 8 receivers and digital processing for determining shear velocity in addition to the conventional p-wave velocity. Neutron logs with 7 detectors are used to determine different types of neutron porosities. Dipmeters with 64 sensors can image stratigraphic dips and fractures in addition to formation dips. Different arrangements of induction electrodes result in higher resolution measurements. Other measurements are now available such as dielectric measurements at several frequencies, nuclear magnetic measurements, acoustic or induction dipmeters, spectral gamma rays, prompt neutron spectral gamma measurements and dipole shear wave measurements.

Where:

Every well drilled that does not have hole problems is usually logged.

Technology References:

Schlumberger Log Interpretation Principles/Applications, 1989.

"The Log Analyst Special Issue – Acoustic Waveform Logging," V32, *The Log Analyst*, No. 3, May–June 1991.

Flanagan, W. D., et al, "A New Generation Nuclear Logging System," SPWLA *32nd Annual Logging Symposium*, June 16-19, 1991.

Dewan, John, *Essentials of Modern Openhole Log Interpretation*, 1983.

IMPROVED LOGGING TOOLS

Purpose:

Logging tools are constantly evolving to produce more repeatable, more accurate, higher resolution measurements in new situations and evaluate more of the signal. New types of measurements are evolving to exploit physical effects that are not currently available in logging suites.

How:

More sensors, more accurate electronics, digital signal processing, and new sensing techniques are improving many of the measurements being made today. Basic research to improve the understanding of petrophysics guides and supports many of the new measurements made.

1990 Technology:

Technology includes high resolution induction logs, dielectric logs, digital array sonic logs, compensated thermal neutron porosity logs, photoelectric density logs, four pad electrical imaging of the borehole, improved dynamically focused borehole acoustic televiewers, Nuclear Magnetic Resonance (NMR) logs that require doping the mud and do not measure total porosity, through tubing pulsed neutron capture logs with neutron porosity measurements, pulsed neutron spectral gamma ray measurements for carbon-oxygen ratios and improved lithology identification, and limited borehole gravity logs.

2000 Technology:

Technology is likely to include improved resolution of laterologs, cased hole resistivity logs, multipole sonic logs, accelerator based neutron and density logs, cased hole density logs, full wellbore electrical images, improved acoustic wellbore images, improved dielectric logs, total porosity NMR logs that do not require doping of the mud, through tubing pulsed neutron spectral gamma ray measurements, and improved borehole gravity logs.

Results:

Log analysts, geologists, and engineers will be provided with improved information to evaluate formations, especially in thin beds and cased holes. NMR and improved Stoneley wave acoustic logs will provide some information on permeability. Accelerator-based nuclear logs will provide improved safety and more repeatable measurements. Improved imaging logs should provide better fracture detection and stratigraphic interpretation.

AMPLITUTE VERSUS OFFSET (AVO)—EXPLORATION

Purpose:

The Amplitude-Versus-Offset (AVO) analysis technique is a process whereby prestack seismic data is examined to determine the presence of gas within a geologic reservoir. AVO analysis has played a significant part in the exploration and development of natural gas.

How:

Seismic data is normally analyzed after stacking the common depth point (CDP) gathers. At this point, among others things, high amplitude seismic events (bright spots) can be identified; a significant percentage of these events are directly related to gas reservoirs. AVO analysis, involving inspection of pre-stack CDP gathers, is a step beyond simply looking for bright spots and reduces the risk of drilling a well based on the bright spot technology. The CDP gathers are displayed as seismic signals of varying amplitude in a time versus receiver offset field. Normally, the amplitude of the seismic events decrease as the receiver offset distance increases. However, the presence of even small amounts of gas in a sand can often cause the amplitude of these events to increase as the offset increases. This is significant because reflections from most lithologies including: shales, tight shaley sands, wet clean sands, or oil sands will show a decrease in amplitude with offset.

1975 Technology:

The AVO technique was not in place at this time, although a precursor technique, bright spot exploration, was extensively used.

1990 Technology:

The state-of-the-art for AVO technology includes: (1) modeling AVO responses at key lithologic interfaces, (2) modeling the AVO response of overpressured shales, (3) generation of CDP gather models to determine the effect of thin bed interference and transmission losses on AVO response, (4) generation of Zoeppritz plots where the modeled AVO response is graphically displayed as trace amplitude versus offset, (5) much better processing techniques in preparation for AVO analysis, including: better noise attenuation, prestack multiple attenuation, true relative amplitude processing and wider bandwidth, (6) improved AVO analysis/interpretation of field data to better determine the presence of hydrocarbons, the extent of the hydrocarbon trap and reservoir quality, (7) improved display of seismic sections where the computed AVO response is overlain in color on top of the seismic traces, and (8) direct comparison of borehole results to pre-drilling predictions. As a simple rule of thumb, if the zero offset amplitude (positive – peak, negative – trough) is multiplied by the slope of the change in amplitude with offset (positive or negative), a positive product indicates a gas charged reservoir. This is only possible when the zero offset amplitude and the slope term are both the same sign, positive or negative.

Future Technology:

Improvements in AVO technology include: better characterization of pre-drill 'positive' AVO results, i.e., less qualitative and more quantitative answers and better post-drilling analysis (more case study analysis). Besides AVO inversion, some near future AVO techniques include more AVO analysis in association with 3-D seismic and cross-well tomography.

Result:

AVO has greatly increased the chances of success for finding gas reservoirs in the Gulf of Mexico region. AVO has been touted as a Direct Hydrocarbon Indicator (DHI) and has been credited with the discovery of hundreds to thousands of BCF of natural gas in this same region.

Where:

AVO is currently used almost exclusively in the Gulf of Mexico region. New AVO directed research will eventually push the technology into other gas rich basins.

Technology References:

SEG Continuing education course presented at the 53rd SE12.5G Annual International Meeting, "Seismic Lithology," F. Hilterman, 1983.

Geophysics, "Plane-wave reflection coefficients for gas sands at nonnormal angles of incidence," W. J. Ostrander, vol. 49, pp. 1637-1648, 1984.

Geophysics, "A Simplification of the Zoeppritz equations," R. T. Shuey, vol. 50, pp. 609-614, 1985.

These references are some of the earliest and best articles on AVO and deal with both the theoretical aspects of the AVO technique and lithologic implications.

Oil and Gas Journal, "Seismic hydrocarbon indicators lower risks," O. Welper, J. L. Allen, G. Fiongos, Nov. 4, 1991

This is a recent, general synopsis of AVO and what it has it has done for the industry and where.

Geophysics: The Leading Edge, "Is AVO the seismic signature of lithology? A case history of Ship Shoal-South Addition," F. Hilterman, June 1990.

This article is a more analytical discussion of AVO including discussion of rock physics and a case study example.

BRIGHT SPOT—EXPLORATION

Purpose:

The bright spot (high seismic amplitude) technique was a revolutionary tool used by geophysicists, from the 70s through the early-80s, as a means to find natural gas in the subsurface. It was initially thought of as a Direct Hydrocarbon Indicator (DHI). However, since there are many geologic instances where bright spots are not indicative of gas in the rock pore volume, this technology is now used in conjunction with Amplitude-Versus-Offset (AVO), analysis which offers the geophysicist more precision.

How:

Bright spot technology is based on the principle that many gas-saturated sands in the Gulf Coast have a lower compressional (P) wave velocity than surrounding shales or water-and oil-saturated sands. The comparatively low velocity gas-saturated sands produce a substantial velocity contrast across surfaces bounding the gas layer. A strong velocity contrast between layers will in turn produce a similarly strong acoustic impedance at these layers. The greater the impedance between layers, the greater the amplitude of the seismic reflection (positive or negative). Therefore, observation of an anomalously high amplitude seismic reflector can be related to an accumulation of natural gas.

1975 Technology:

During the mid-70s to early-80s the bright spot technique was used extensively, especially in the offshore Gulf of Mexico. One of the key elements of this technology involved appropriate processing of the seismic data. By far, most seismic data of this time had Automatic Gain Control (AGC) applied to it to attain a more visually pleasing section for interpretation. Unfortunately, this process can alter vital amplitude information being sought. Relative Amplitude Processing (RAP) is an attempt to preserve the correct amplitudes of the data from trace to trace. Application of RAP processing was essential to improving bright spot analysis.

Through drilling and computer modeling, it was determined that even small amounts of gas (<10 percent of the rock pore volume) can cause a substantial decrease in P wave velocity. These amounts may be well below what is considered commercial reserves. Although Bright Spot techniques were fairly successful in finding numerous gas charged reservoirs, it could not be reliably used to determine the volume of reservoir gas. False bright spots may be caused by facies changes, geometric focusing, or by certain geologic conditions, e.g., oyster banks within a shale, water-bearing gravels, or hard streaks.

1990 Technology:

There is no 'bright spot' research per se currently being done. However, earlier research in bright spot technology has evolved, through the mid-80s, primarily into Amplitude-Versus-Offset (AVO) analysis.

This work is helping to eliminate some of the ambiguities in bright spot prospecting.

Result:

Although not exactly a DHI, the use of bright spots as a geophysical tool has proven to be successful in adding substantial volumes of natural gas to our domestic reserves. The greatest domestic success occurred in the Gulf of Mexico region. This prospecting technique has also led directly to the development of AVO technology.

Where:

Domestic exploration/development geophysicists mainly used the bright spot technique in the Gulf of Mexico region, although other U.S. basins have enjoyed limited success.

Technology References:

Introduction to Geophysical Prospecting, M. B. Dobrin, pp. 14-15,345-347, 1976.

Seismic Stratigraphy—applications to hydrocarbon exploration, AAPG Memoir 26, "Applications of Amplitude, Frequency, and Other Attributes to Stratigraphic and Hydrocarbon Determination," M. T. Taner and R. E. Sheriff, pp.301-327, 1977.

Seismic Stratigraphy—applications to hydrocarbon exploration, AAPG Memoir 26, "Geologic Considerations for Stratigraphic Modeling and Interpretation," L. D. Meckel and A. K. Nath, pp.417-438, 1977.

Seismic Stratigraphy—applications to hydrocarbon exploration, AAPG Memoir 26, "Practical Stratigraphic Modeling and Interpretation," M. W. Schramm, Jr., E. V. Dedman, and J. P. Lindsey, pp. 477-502, 1977.

IMPROVED UNDERSTANDING OF RESERVOIR GEOMETRY

Purpose:

The geometry of a reservoir incorporates two concepts. First, reservoirs have an external geometry that relates to the separation of reservoir and non-reservoir facies. Second, they have an internal geometry that controls recovery and continuity of flow units that affect recovery efficiency. Improvements in our understanding of both external and internal geometries will result in lower finding costs and improved recoveries.

How:

The techniques currently in use include probabilistic realizations, quantitative dynamic stratigraphy models which simulate basin fill processes using basic sedimentologic and stratigraphic principles, and empirical approaches such as sequence stratigraphy. These empirical techniques use seismic data, climatic and tectonic models to predict the distribution of reservoir bodies. On a smaller scale, outcrop studies are used to characterize facies architectures. The progress that has been made in defining internal architecture creates opportunities for improving recovery incrementally from known reservoirs.

1990 Technology:

Empirical techniques that take facies architecture concepts and apply them to subsurface data are most commonly employed. Statistical approaches are available and beginning to be more widely used as computer technology makes them more readily available to greater numbers of users. Outcrop studies of facies tracts place increasing emphasis on determining what constitutes a flow unit in the subsurface. More and more, analysis of reservoir and framework grain geometry is being integrated with subsurface flow geometry and analysis of pressure variations. Traditionally, these analyses have been developed relatively independently of one another.

2000 Technology:

The increasing affordability of computer power will facilitate the integration of conceptual modeling of reservoir geometry with deterministic assessments of external and internal reservoir geometry as will be provided by cross-well seismic tomography. A key development for the future will be to improve the integration of reservoir geometry and reservoir engineering analyses.

Result:

New technology that integrates reservoir characterization with flow-unit analyses will decrease the cost of finding new reservoirs and improve the recovery efficiency of known reservoirs.

ENHANCED GAS RECOVERY IN CONVENTIONAL RESOURCES

Purpose:

To access incremental production beyond reserves produced using "conventional" development practice.

How:

Reservoir heterogeneity creates barriers to gas flow such that development at conventional well spacings leaves a significant portion of reserves untapped. In reservoirs with moderate to good permeability, the resource is found in untapped and incompletely drained reservoir compartments, by-passed gas zones and deeper pools. Finding this resource depends on integration of geology, geophysics, reservoir engineering, and formation evaluation.

1990 Technology:

Presently, a wide range of techniques such as three-dimensional seismic, cased hole logs, detailed sequence stratigraphy and pressure interference testing can be used to identify incremental reserves. Many older gas fields, however, have not been analyzed using these techniques and may be excellent opportunities for enhanced recovery. Most of this data is not analyzed in a truly integrated approach, in part because the paper records are hard to locate and cumbersome to analyze concomitantly. Integrated interpretation systems have been developed to facilitate this work, but the problem of data entry and data integrity remain a significant barrier to their optimum utilization.

2000 Technology:

Integrated interpretation systems will be much more powerful and will incorporate tools to check data integrity. Easier methods of data entry such as optical scanning are likely to dramatically increase the use of these systems. Development of new technologies for identifying reservoir heterogeneities between wellbores (e.g., cross-well seismic tomography) and for identifying gas behind pipe (e.g., cased hole density logging) will significantly improve our ability to locate incremental reserves within existing fields. Also, improved production strategies and techniques for decreasing the problems of drilling through depleted reservoirs will improve the cost effectiveness of this resource. Studies to determine which techniques to apply and where to apply them will be just as important as the development of new technologies. Screening methods that help engineers and geologists determine which fields and which reservoirs have a significant incremental resource will help target the deployment of technology.

Result:

Improved understanding of how reservoir heterogeneity affects gas flow will show where incremental resource is to be found and how to access it. Targeted application of new technologies combined with integrated studies of the reservoir framework and its flow properties will greatly improve the economics of this process.

COPRODUCTION

Purpose:

Significant quantities of natural gas remain trapped in water-drive gas reservoirs at abandonment using conventional production and reservoir management techniques.

The process of coproduction involves high volume brine production as a means of recovering this gas that would otherwise remain in the reservoir.

How:

Large volumes of brine are produced from a water-drive gas reservoir to lower the reservoir pressure and to allow gas that was trapped by the aquifer to expand. Given sufficient brine withdrawals from the reservoir, this trapped gas will expand until its saturation reaches a critical value and flow toward the wellbore commences.

Cost-effective handling and disposal of the produced brine is a critical element of a coproduction project. Properly designed surface facilities must accommodate upwards of tens of thousands of barrels per day. Injection wells must be capable of taking the produced brine and maintaining injectivity over long periods of time. An efficient program of scale and corrosion control is also required given the volumes of brine that are handled.

1975 Technology:

Conventional production and reservoir management techniques were practiced that resulted in the trapping and subsequent loss of large quantities of natural gas. High water cut gas wells were shut in without determining the effect on the entire reservoir of continued brine production to reduce reservoir pressure.

1990 Technology:

Performance prediction techniques for coproduction reservoirs have been developed. Accurate estimates of the required brine withdrawal rates for gas remobilization are now possible. The process of coproduction has been successfully validated in the field. The Northeast Hitchcock Field in Galveston County, Texas, has produced in excess of nine billion cubic feet of gas since a coproduction project was initiated there in 1980s. Daily brine production rates at this field have exceeded twenty thousand barrels per day.

Result:

Many coproduction project candidates have been identified. The initiation of any project is currently hampered by low gas prices and increasingly tighter regulatory requirements for the handling and disposal of produced brine.

Where:

Most coproduction candidates are in the Gulf Coast area where water-drive is a commonly found drive mechanism. Fields with an existing surface infrastructure are more attractive than fields where large initial capital expenditures are required.

SOURCE ROCKS AS A RESERVOIR ROCK

Purpose:

To produce commercial quantities of hydrocarbons which were generated by organic matter present in the enclosing sedimentary rocks.

How:

Source rocks retain substantial portions of generated hydrocarbons and may have sufficient storage capacity, particularly due to natural fracturing, to be both a source and a reservoir for the hydrocarbons.

1975 Technology:

Hydrocarbon production from sedimentary rocks in which the gas or oil has been generated by thermal maturation of organic matter (see "Source Rock Geochemistry") has occurred since the early 19th century. Gas from Devonian-age shales in the Illinois Basin was produced and piped across the Ohio River for use in Louisville, KY. Gas production may also occur from coal bed source rocks, as well as oil production from organic-rich shales and carbonate rocks. Production rates from such source/reservoir rocks are commonly limited due to the inherent low permeability of the fine-grained rocks themselves. Natural fracturing present in the rocks may allow increased hydrocarbon storage capacity and flow rates, but artificial fracturing ("stimulation") of the rocks is usually required to achieve commercial production. The production characteristics of these rocks may be damaged by water-based fluids used to hydraulically stimulate conventional reservoir rocks. This factor, combined with the poor economics associated with production from some source rocks, led to an industry reliance on stimulation by wellbore "shooting"—setting off charges of gelled nitroglycerine in the wellbore to increase flow rates from the formation. This technology considerably predated hydraulic stimulation. Production from "shot" wells was often only marginally economic, perhaps due to damage to the formation caused by the explosives. While the potential resource, particularly the gas resource, was several times that present in conventional reservoir rocks, production was limited by low flow rates and subsequent economics. This led to efforts by industry and government in the mid-1970s to enhance production from source/reservoir rocks.

1990 Technology:

New technology and improvements to existing technology to artificially stimulate production from source/reservoir rocks continues to this time. Success has been achieved, through work sponsored by production companies, the Gas Research Institute and the U.S. Department of Energy, in increasing gas production from organic-rich shales of the Appalachian, Michigan, and Fort Worth basins, and coal beds in the San Juan, Warrior, Powder, Piceance, and other areas. Specialized fluids and low-water content foams are used to limit damage to the gas-bearing rock formations. Wellbore "shooting" has become the exception. Real-time monitoring of the stimulation treatment to optimize artificial fracturing and the development of novel completion techniques, such as cavity completions in coal beds, result in improved production rates and total hydrocarbon recoveries. The development of horizontal drilling techniques to encounter a larger number of fractures within the hydrocarbon-bearing formations has substantially increased production in multiple areas of the country, such as oil from the Bakken Shale of the Williston Basin and the Austin Chalk of Texas. Methane from coalbeds, previously seen as a hazard to miners, now comprises a substantial portion of natural gas production in the geologic basins named above. Technology to evaluate production by improved well testing and formation evaluation procedures has been developed to increase ultimate hydrocarbon recoveries. Geologic modeling to determine the presence of source/reservoir rocks in time and space, and the possible location of increased natural fracturing has also improved the ability to explore for commercial deposits of hydrocarbons.

Where:

Companies offer exploration, drilling, formation evaluation, well testing, and stimulation services to industry.

Technology References:

A large body of literature exists, from such organizations as the Gas Research Institute, U.S. Department of Energy, and professional journals, concerning hydrocarbon production from source rocks. Sample references follow:

American Association of Petroleum Geologists, "Geological Aspects of Horizontal Drilling," Continuing Education Course Notes Series #33, edited by R. D. Fritz, M. K. Horn, and S. D. Joshi, 1991.

> A set of papers covering source rocks, drilling, completion, and formation evaluation of horizontally drilled formations.

Rocky Mountain Association of Geologists, "Coalbed Methane of Western North America," edited by S. D. Schwochow, D. K. Murray, and M. F. Fahy, 1991.

> A series of papers covering coalbed methane exploration, completion, and formation evaluation technologies.

American Association of Petroleum Geologists Memoir 35, "Petroleum Geology of the Bakken Formation, Williston Basin, North Dakota and Montana," F. F. Meissner, 1984.

> Discussion of oil generation and production from fractured shales, applicable to other areas.

IMPROVED DOWNHOLE SOURCES FOR CROSS-WELL SEISMOLOGY

Purpose:

For commercial viability, a cross-well seismic system must be capable of high signal frequencies useful for resolving heterogeneous features of the order of about 10 feet. In reservoir rocks, this requirement translates to a minimum bandwidth of approximately 1,000 Hz.

How:

There is probably no single source technology that can meet the needs of all reservoir environments. Generally, the source must (1) have low peak stress to avoid damage to borehole casing and rock, (2) produce controllable and repeatable waveforms at short cycle times,for rapid data acquisition, (3) be broadband, (e.g., 100–1,000 Hz), (4) generate both P and S waves, (5) be deployable at depths exceeding 10,000 feet, and (6) operate continuously at reservoir temperatures of 150 C for up to 24 hours. Sources potentially capable of meeting these requirements can be classified by the mechanism used in converting energy into mechanical vibrations. These are (A) wall-clamped vibrators (hydraulic, pneumatic, and electromagnetic), (B) fluid-coupled electrostrictive vibrators (piezo-ceramic and magneto-strictive), and (C) impulsive (air guns, chemical explosives, sparkers).

1990 Technology:

The first class reviewed is the wall-clamped vibrator (hydraulic, pneumatic, and electromagnetic). These are all swept frequency sources. The hydraulic type has been used for field surveys but only in shallow, dry boreholes. It is a powerful and effective source. The hydraulic vibrator produces a broadband signal spectrum between about 50 and 500 Hz. The limited frequency capability will ultimately limit resolution for reservoir characterization applications. Wall-clamped vibrators, because of their high power and low frequencies, are probably the best candidate for large well spacings in poorly consolidated rocks such as the Gulf of Mexico.

The second class of viable downhole technology is the fluid-coupled piezo-ceramic vibratory source. This source is extremely efficient, can be pressure compensated, can work at high temperatures, operates on standard logging wireline, and has been used in logging for years. The main drawback is the lack of strong low frequency content below about 300 Hz, thus limiting operation to harder, more consolidated formations. However, it is well-suited for high resolution reservoir imaging applications. Newer piezo-ceramic sources are overcoming the power and low frequency limitations of the earlier prototypes. Although a commercial version is not yet available, prototypes of various designs are experiencing the most widespread use in the field today. Piezo-ceramic sources are extremely repeatable, reliable, easy to operate, and are probably best suited for high resolution imaging of deep consolidated formations.

Other technologies for deep production well applications are the impulsive sources—air guns, sparkers, and explosives. Air guns have experienced the most extensive field use, mostly in shallow thermal monitoring applications. The guns work by releasing high pressure air into the borehole. The air gun is inefficient and only moderately repeatable. Although it is the only commercially available source, few users see it as a long term solution for reservoir characterization problems. Borehole sparkers and chemical explosive sources suffer many of the same shortcomings. In many oil and gas fields, explosive sources are not permitted repeated use in production wells.

Future Technology:

Of the candidate technologies, only two, fluid-coupled piezo-ceramic vibrators and wall-clamped hydraulic vibrators, are considered operationally and economically viable over the next five years. The piezo-ceramic source, because of its resolution capability, operational ease of use, and lower engineering cost to develop, is expected to be the best choice for high resolution imaging (especially in gas fields with harder rocks) for the next 3–5 years.

Result:

Improvements in downhole sources for tomography will lead to much better reservoir characterization, which will in turn lead to improved development of gas fields.

Where:

The hydraulic well-clamped vibrators are best suited for work in areas where the rocks are poorly consolidated, such as the Gulf of Mexico. Where the rocks are more consolidated, the Permian basin, basins of the Midcontinent, etc., the piezo-ceramic source is best.

Technology References:

Expanded Abstracts, Sixty-First SEG Annual International Meeting, "Comparison of borehole seismic sources under consistent field conditions," D. L. Howlett, 1991.

Geophysics, "Seismic sources in open and cased boreholes," G. A. Winbow, vol. 56, pp. 1040–1050, 1991.

REAL PERMEABILITY LOGGING

Purpose:

To determine the permeability of the formation from a continuous wireline log without testing or coring.

How:

Develop logging techniques that measure phenomena associated with permeability such as actual fluid movement or surface area. Two physical effects that do this are: (1) Stoneley waves, which are affected by sloshing of the fluid in the pore space; and (2) nuclear magnetic resonance (NMR), which is affected by the surface area in sandstones.

1990 Technology:

Stoneley waves are measured by full waveform digital array sonic logs. Some commercial logs are still affected by the tool design during the Stoneley arrival. In addition a complete understanding of the petrophysics of Stoneley waves still needs to be developed before this application is practical.

Only one commercial NMR logging tool exists in 1990. It requires doping of the drilling mud with a minute amount of magnetite to run the tool. To predict permeability, the NMR log must be combined with a porosity log, even then predictions are only valid in sandstones.

2000 Technology:

Better Stoneley wave measurements will be available from all major vendors of logging tools. A better understanding of the major effects on Stoneley waves should be available so that log analysts will know when Stoneley waves will and will not accurately measure permeability.

New NMR logging tools that do not require doping of the mud should become available. These will also measure total porosity because of a decrease in the dead time for the first measurement. New generation NMR tools require downhole permanent magnets. Improvements in magnet technology should improve the signal-to-noise ratio of these logs over time.

Results:

Both of these logging techniques should improve the ability to predict permeability from logs. However, all types of rocks will probably not be covered by these two techniques. Although measurements of permeability will be available, the need for core and test data will still exist. Relative permeability and permeability anisotropy will still need to be known; these parameters will still need to be measured from core or testing.

THROUGH CASING PRESSURE DETECTOR

Purpose:

To determine pressure in cased wells for fluid density gradients, compartmentalization, and depletion.

How:

Pressures can be measured in cased hole by perforating a hole in the pipe than measuring formation pressure with a pressure gage. Gas density effects related to pressure affect other physical properties which can be measured by other logging tools.

1990 Technology:

Currently there are wireline formation test tools that can perform one or two shape charge perforations and pressure measurements per descent into a cased well. Resealing of the perforations is not currently possible, although it has been attempted in the past.

Cased hole pulsed neutron logs have been used to detect pressure changes in high porosity clean formations and laboratory measurements of sonic properties of rocks have indicated some effects of gas pressure on sonic travel times. These effects are capable of measuring only very large scale changes in gas pressure under relatively ideal conditions.

2000 Technology:

Cased hole formation tester tools should evolve to take multiple readings in cased holes with effective re-sealing of the casing after each test.

Results:

Compartmentalized gas reservoirs, bypassed gas reservoirs, and depletion of conventional reservoirs will be monitored more effectively and efficiently.

VERTICAL PERMEABILITY MEASUREMENTS

Purpose:

The vertical permeability of gas reservoirs is a highly variable parameter that affects the vertical movement of fluids through reservoir rock. Vertical permeability measurements are needed to accurately represent the entire reservoir in order to model the production of gas from compartmentalized and multiple layered reservoirs.

How:

Vertical permeability can be highly variable in the rocks which comprise gas reservoirs. The permeability difference between facies changes can be several orders of magnitude. Vertical permeability differences create permeability streaks and barriers which can result in layering and compartmentalized reservoirs. In unfractured reservoirs, the variability in vertical permeability impacts the flow of fluids through the rock reducing gas production. This affects the drainage radius which determines the optimal well spacing and the economics of reservoir development.

1990 Technology:

Vertical permeability is measured from core samples, inferred from production matching, and calculated from multiple. Chambered formation pressure test data. Core sample measurements can yield absolute and relative permeability over the sample length. Effective vertical permeability can be inferred by matching long term production data to reservoir models. Vertical permeability is computed from log correlations as is currently done for horizontal permeability.

2000 Speculative Technology:

Better vertical permeability correlations will be developed in thinly layered media due to higher resolution logs which can be correlated to finely laminated core measurements and summed in series. Relative vertical permeability and vertical capillary pressure technology will be developed. Formation pressure testing devices will have multiple probes for pressure data over a depth interval from which effective vertical permeability can be computed. Better reservoir models will improve inferences of vertical permeability by improved matching of long term production data and data input from new sources.

Results:

Improved vertical permeability measurements will improve the understanding of reservoir performance. This will impact development of new fields and infill drilling of existing reservoirs.

SOURCE ROCK GEOCHEMISTRY

Purpose:

To use organic geochemical data to locate and evaluate hydrocarbon source rocks, migration pathways and reservoirs.

How:

Analysis of organic compounds present as parent kerogen and daughter bitumen, natural gas and petroleum, can yield information on the location, timing, and size of reservoirs, through increased understanding of the origin and fate of hydrocarbons in the subsurface, analyses are commonly performed on both core and cuttings samples.

1975 Technology:

Chemical techniques to analyze hydrocarbon source rocks were initially adapted from methods employed by coal chemists. Basic organic geochemical parameters, such as Total Organic Carbon concentration, bitumen composition, organic matter type and thermal maturity, were readily determinable, although often by labor-intensive, wert chemical methods. Modeling techniques used to interpret the data in terms of the geological environment were relatively simple and rely on numerous simplifying assumptions about burial histories of the sediments, temperature gradients, through time and the chemical behavior of the organic matter itself. Source rock geochemistry was often used in a negative sense to condemn areas of a basin as hydrocarbon-poor, rather than as a technique to assist in location and subsequent evaluation of commercial reservoirs.

1991 Technology:

Advances in instrumentation have facilitated increased understanding of the role of source rocks in the formation of hydrocarbon deposits and improved our ability to exploit this understanding for exploration. Pyrolysis of potential source rocks allows a rapid, cost effective look at the quantity, quality and thermal maturity of organic matter, as well as prediction of the expected product—gas, condensate, or oil. Gas chromatography–mass spectrometry (GC/MS) analysis of biomarkers, specific organic compounds present in source rocks and crude oil, allows improved assessment of thermal maturity, provenance of the organic matter, and correlation between sourcebeds and generated crude oils. The ability to measure isotopic compositions of separate compounds allows increased understanding of the relationships between source beds and hydrocarbon generation has advanced with availability of increased computing power and the ability to measure certain parameters of hydrocarbon generation. Source rock geochemistry methods are now used to calculate the potential size of the deposit and to provide insight into its geographic extent, migration pathways and depositional environment off reservoir sediments.

Where:

Core analysis laboratories offer state of the art geochemical analyses, and interpretive reports for the user.

Technology References:

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AAPG Memoir 35, 1984, "Petroleum Geochemistry and Basin Evaluation," edited by G. Demaison and R. J. Murris.

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AIR DRILLING

Purpose:

To drill oil and gas wells as quickly and inexpensively as possible with a minimum amount of formation damage with air circulation to replace conventional mud systems.

How:

Drilling with air is accomplished by circulating high volumes of air rather than mud, to remove drill cuttings and cool the bit. The underbalanced condition of having no fluid in the hole significantly improves the rate of penetration over that of mud systems. Without the presence of drilling fluid there is no damage caused by drilling fluid invasion. Well control is a special concern, which limits application to often less productive formations that do not produce commercial amounts of gas and little or no oil and water while drilling.

1975 Technology:

Cable tool drilling was fading due to the speed of air drilling. The speed of air drilling had established it as a cheap method to drill wells. Air drilling featured a mixture of equipment, from rigs to air compressors. The rigs varied from driveable mobile rigs to jack knife rigs hauled by trucks.

1991 Technology:

The streamlining of equipment has resulted in much lower comparative drilling costs, while few advances in technology have been made. Rigs are smaller and almost all self propelled allowing them to move quicker onto smaller locations. Auxiliary equipment is designed for quick transportation from one location to the next on trucks and trailers. Location size savings alone can be up to $25,000/well. Some of these cost cutting moves that have made air drilling cheaper have also been detrimental to safety. Often not used, BOPs are cumbersome and time consuming, if used they are normally small annular preventors with no accumulators and operated by rig air or hydraulics. Smaller locations have shortened blooie line length, now often venting gas dangerously close. Drill bits designed for air application are widely used by drillers, with good results. Other technologies developed have not been accepted by industry due to poor economic conditions.

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IMPROVED FRACTURING FLUIDS

Purpose:

Fracturing fluids are used to create a wide hydraulic fracture and transport proppant deep into the producing formation. The basic fluid used is either oil or water and additives are added to provide the desired fluid rheology and improve the compatibility with formation fluids and rock. The ideal fracturing fluid would have very good fluid loss control so that the volume of fracture created is close to the volume of fluid pumped, have adequate viscosity to give near perfect proppant transport during the pumping time of the treatment and then "break"-undergo viscosity reduction due to viscosity breakers 80 that the fluid can be produced out of the formation and create no damage. Such a fluid would provide for the optimum economic development of low permeability reservoirs.

How:

Gelling agents are used to create viscosity, fluid loss additives to prevent fluid loss from the fracture, breakers reduce viscosity after a period of time, surfactants reduce surface tension and improve fluid recovery, and clay control chemicals to prevent clay swelling and fines migration. The proper selection of each additive is required to achieve optimum performance of the fracture stimulation treatment.

1975 Technology:

In 1975, over 90 percent of the fracturing treatments were performed with 2 percent KCl solution in water containing hydroxypropyl guar (HPG) to provide viscosity and crosslinked with a variety of crosslinkers. A crosslinker increases the viscosity of the gel solution by chemically tying polymer molecules together. The available crosslinkers suffered extensive shear degradation while being pumped down the tubular goods, thus reducing the viscosity and proppant carrying capacity. Breakers reduce the viscosity of the fracturing fluid, but if an adequate breaker concentration was added to minimize the permeability damage due to the gelling agent in the proppant pack, then the premature viscosity degradation significantly compromised proppant transport. Using this level of technology, a large number of reservoirs were economically developed. However, examples of stimulation failures were often observed.

1990 Technology:

High friction pressure and premature viscosity degradation in the tubular goods has been solved by the generalized availability of delayed crosslinking agents that are released as a function of time and temperature. Delayed crosslinking formulations are available for the zirconates, titanates, and borates which are the principal crosslinkers used today. Premature viscosity degradation and loss of proppant transport due to breakers has been improved by the availability of encapsulated breakers which provide for a timed release of the breaker. A large armament of fluid additives have been developed to improve formation compatibility of the stimulation fluid. These include nonemulsifiers, scale inhibitors, enhanced fluid recovery additives, paraffin inhibitors, and clay and fines migration control additives. In some ways, the availability of large numbers of additives and fluid formulations has made it difficult for the fracture design engineer to select the proper fluid formulation to optimize production from a given reservoir. Extensive field quality control testing has been recognized as a major factor in improving the field performance of fracturing fluid systems. Furthermore, computerized fracturing equipment has proved to be instrumental in delivering the chemical additives at the design concentration.

Future Technology:

Even with the above advances, a number of unconventional reservoirs such as coalbed methane, Devonian shale, and lenticular tight gas sands have not been successfully economically exploited with conventional technologies. In some cases this may be related to the improper application of available technology, while in other cases it will depend upon future developments in fracturing fluid additives and design procedures to successfully complete these reservoirs. Most unconventional reservoirs have very fragile permeability systems which are much more susceptible to treating fluid damage than is observed in more conventional reservoirs. Advances in the understanding of the key design parameters for these reservoirs will be required to properly apply conventional technologies and develop improved systems.

Immediate fracturing fluid improvements that could advance the state of fracturing technology include: (1) fluid and breaker combinations that degrade controllably at low temperature; (2) non-damaging fluids for the 180–250°F temperature range; (3) coated proppants that do not interfere with fracturing fluid cleanup and control proppant flowback; and (4) neutral density higher strength materials for use as propping agents

Technical References:

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Gulbis, J., "Fracturing Fluid Chemistry," in Economides, M. J. and Nolte, K. G., *Reservoir Stimulation*, Schlumberger Educational Services, Houston, TX (1987) (Chapter 4).

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Ely, J. W., Wolters, B. C., and Holditch, S. A., "Improved Job Execution and Stimulation Success Using Intense Quality Control," paper present at the 1989 Southwestern Petroleum Short Course, Lubbock, TX.

REAL GAS CONTENT LOG FOR SHALE AND COAL

Purpose:

To identify and quantify the gas content in shale and coal. This will provide a rationale for choosing completion intervals, and improve the accuracy of gas in place calculations. As a result, economic feasibility, completion design, treatment design, and production performance will be enhanced.

How:

Integrate core data with log data to determine accurate mineral composition of the shale, and physical properties of coal, and use these base results to determine gas content. Gas content in the shale is determined from relationships of porosity, bulk water volume, and bulk gas volume. In the case of coal, logs determine the physical properties that are then related to adsorbed gas content.

1975 Technology:

Log evaluation for gas content in shales consisted of the identification of gas entries using temperature logs, and using the gamma ray to determine organic "Hot" zones and clean zones with increased silt content. Generally, completions were performed over the entire shale interval and little was known regarding which perforations were actually producing.

Coals were not evaluated for gas content using log data in 1975. At that point in time, the oil and gas industry had not focused on the potential resource and the mining companies were primarily interested in seam thickness from logs. Estimates in gas content were aimed at mine safety rather than a producible resource.

1990 Technology:

Advancement in the measurement of porosity in shale cores has allowed the integration of modern advance logs, such as the photoelectric effect (PEF) and the gamma ray spectroscopy log, to determine accurately the major mineral constituents of the shale. From this base knowledge, log measurements can be corrected for the effects of mineral constituents such as kerogen and pyrite resulting in accurate log-based porosity, bulk volume water, and volume gas in the shale. Additionally, comparisons of core-derived porosity and bulk volumes of water, gas, and oil have demonstrated that shale porosity greater than 3 percent supports hydrocarbon storage (Devonian Shales Appalachian basin). As a result, selective completions are possible and production logs have proven the success of this methodology to identify gas-bearing zones and allow the calculation of gas in place.

As the oil and gas industry has identified the importance and potential of coalbed gas, increased effort has been directed at log evaluation (from mineral logging companies and oil and gas logging companies) for the determination of gas content. The thrust has been to correlate log response (particularly bulk density) to proximate analysis from core data. A stumbling block in the technology is that the core measurements that would be used to provide "ground truth" for the evaluation of the logging measurements are not standardized, and in many cases were developed for specific mining purposes, not the determination of gas reserves and producible gas. Therefore, discrepancies between core and log correlations are encountered and the reliability of current log-based models are more difficult to assess.

Future Technology:

Advances in standardization of core analysis techniques plus further development and integration with log response data will allow determination of matrix and fracture permeability in the shales, and more consistent log correlations in coal evaluation. Additional effort will be aimed at determining the gas and water saturations contained within the cleat system of the coals.

These results will then be used to model and predict the actual deliverability of the shale and coal. The direct benefits will be economic evaluation, completion design, treatment design, and production performance that is enhanced and easily evaluated.

Where:

This technology will be of benefit anywhere shale and/or coal are evaluated for the potential of gas production. Some domestic examples include the following:

Shale

Appalachian basin (Devonian)
Michigan basin (Antrim)
Illinois basin (New Albany)
West Texas (Barnett)
California (Monterey)

Coal

San Juan basin
Black Warrior basin
Appalachian basin
Piceance basin
Raton basin

Technological References:

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Colson, J. L., "Estimating Methane Content of Bituminous Coalbeds From Adsorption Data," Schlumberger Abstract, presented at the SPE Gas Technology Symposium, Houston, Texas, January 22-24, 1991.

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PROPELLANT FRACTURING

Purpose:

Many formations, subsequent to drilling, or after long periods of shut-in, are not economically productive due to near-wellbore damage or marginal permeability. The purpose of propellant fracturing is to improve the near-wellbore flow conditions in these wells quickly and economically.

How:

Solid propellants, usually in cylindrical form, are lowered into the well by wireline or tubing and ignited with an electrical detonating system. The resulting high-pressure gaseous propellant burn products penetrate the formation in the form of multiple fractures extending up to several tens of wellbore radii and create permeable channels for flow. Propellants are not explosives. Propellants will not detonate under normal circumstances. Their rapid burning, rather than detonating character, permits the creation of extending fractures. Propellant use is either open hole or through perforations.

1975 Technology:

Propellant fracturing was in existence but not generally known. The method was offered only on a limited basis. Tools and ignition systems were relatively primitive and somewhat unreliable. The actual downhole action of the propellant charges was unknown, except by empirical after-the-fact observation. Propellants were ignored by most engineers, but others thought of them incorrectly as possible methods of massive stimulation. Misapplications occurred, although enough successes were achieved to begin the growth of a small industry.

1990 Technology:

Over the past 15 years, the U.S. Department of Energy, the Gas Research Institute, and private industry have funded research in propellant fracturing technology. Some milestones have been: (a) field mineback demonstrations that propellant fracturing actually creates extending multiple fractures (Warpinski, et al., 1979) and associated computer modeling (Nilson, et al., 1985), (b) the development of a laboratory scale modeling, concurrent computer modeling, and downhole dynamic pressure measurement techniques that indicate the important parameters of fracture creation and extension by propellants. (Schatz, et al., 1987), and (c) the beginnings of formal recognition by the oil and gas industry that propellant fracturing is useful in certain circumstances (Hunt and Shu, 1989). The propellant fracturing industry, however, remains small because of a perception of limited usefulness and a lack of the application of previous research results to the design of new and more effective tools. A remaining research topic is to what extent propellant-generated fractures remain self-propped in various formation types, and how to create or enhance self-propping effects.

Future Technology:

Propellant tools can be ideal for certain near-wellbore applications. Limited applied research is now going on to enhance conventional perforations with propellants and to stimulate extremely long sections of horizontal holes with propellants. Either of these, if successful, could bring propellant fracturing much more into the main stream by the year 2000. The optimal development of propellant fracturing in the future will require more effort in specialized tool design to take advantage of behavior now known and understood, but not yet applied to tool design.

Results:

Optimized propellant tools and procedures are economic methods of improving near-wellbore connection in some formations and conditions. Increasingly, propellant applications are made correctly and appropriately due to improved knowledge.

Where:

Propellant fracturing has been used worldwide, although most applications have been in the U.S. and Canada. Most successes have occurred in shallow to intermediate depth wells with originally adverse near-wellbore conditions.

References:

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Hunt, W. C. III, and W. R. Shu, "Controlled Pulse Fracturing for Well Stimulation," Proc. SPE Joint Low Permeability Reservoir Symposium, pp. 445-450, Denver, CO, 1989.

COMPUTERIZED DATA INTEGRATION

Purpose:

To integrate geotechnical, engineering, production, and econometric data for optimization of the entire process from exploration to production, transportation, storage, and sales.

How:

Acquisition of large volumes of data and application of this data in simultaneous solution of multi-variant problems has become possible through advances in computer and communication technologies. On a small scale, accurate deductions from analysis of any given data set must satisfy the constraints imposed by other data sets and, on larger scale, optimization needs to be designed and implemented on the basis of the information in its entirety. This implies that users will need to access extremely diverse data through a "global" communication platform.

1975 Technology:

Integrated data systems were practically nonexistent in early 70s. Use of computerized data analyses was "departmental;" i.e., each technology group had its own data set and performed independent simulation and analysis. The idea of integrated databases came into being toward the end of the decade.

1990 Technology:

Integrated data systems are being developed, albeit still in a fragmented fashion. Seismic, petrophysical, and geological information can be accessed by a user with no major difficulty. However, integration with other geophysical information (e.g., potential field data) and reservoir engineering data is not quite as simple. It needs to be pointed out that achieving the objective of this whole concept requires coupled simulations of many multi-variant conditions for which a fully integrated system is a prerequisite. It is anticipated that fully integrated systems will be available by mid-1990s.

Result:

Utilization of fully integrated information systems allows for optimum field development designs and exploitation plan through maximized reserve recovery and minimized capitalization and operations costs. The link with econometrics models provides real-world constraints on price/supply/cost predictions. This will be a crucial decision-making tool at corporate levels.

Where:

Primary areas of application will be in larger field settings such as those of Texas and Oklahoma. The technology will then go through the normal technology diffusion process. It is anticipated that operators of any field with 75 or more wells will be potential users of the integrated data systems. The ultimate product will play a major role on larger exploration projects and long-term planning.

CHEAPER DIRECTIONAL DRILLING

Purpose:

Directional drilling technology gives drilling engineers a broad range of possibilities for planning wellbore designs and trajectories. Directional drilling technology has made possible the development of limited access locations, such as offshore discoveries where multiple wells are drilled from one structure. Other applications of directional drilling technology include horizontal drilling and relief wells, where a directionally drilled well is used to intersect and control a blowout.

How:

The trajectory of a wellbore is planned to intersect desired targets located at known depths and displacements from the wellbore. Typically, the wellbore is deflected from vertical as the well is being drilled to follow the planned well path. Special tools are used during the drilling process that allow the well to be guided in the desired direction. These tools are typically comprised of mud motors to provide power to rotate a drill bit and a device to orient the drilling tools and monitor the trajectory of the well path such as an MWD tool.

Direction drilling operations are more expensive to conduct than vertical drilling operations because they require specialized personnel, additional equipment, and are more time consuming

1990 Technology:

Cheaper directional drilling technology is due to the improvements that have been made in drilling tools and directional surveying. Directional drilling tools have evolved from mud motors and bent subs that required them to be removed from the well to make adjustments in the hole trajectory into sophisticated steerable drilling systems that are capable of drilling a deflected or straight wellbore. MWD or wireline steering tools provide reliable real time directional survey data for monitoring the well trajectory.

2000 Technology:

Directional drilling will become less expensive and more routine. Incremental improvements will continue to be made in bits, mud motors, and MWD tools which will increase the reliability and decrease the operating and maintenance costs of these tools. Directional drilling systems that employ intelligent controls will be developed that monitor and guide the wellbore trajectory with a minimum of human interaction.

Result:

The use of directional drilling technology will increase in the future as it becomes less expensive and more reliable. Production from gas reservoirs will be routinely planned and developed with directional wells. The use of multiple wells from a single pad will be routine on land operations. Offshore development will require fewer platforms as the capabilities and reliability of direction drilling increase and more wells are drilled from each platform.

SLIMHOLE DRILLING

Purpose:

To reduce drilling and completion cost through reduced drilling rig cost and tubular costs.

1975 Technology:

Over 3000 slimholes have been drilled by industry. Many applications have been for exploratory wells in remote locations where access was limited to airlifted equipment.

High drilling and completion costs in the early 1980s promoted the use of cost cutting measures afforded by slimhole wellbores. Difficulties with effective workovers within slimhole tubulars limited their application. Poor small diameter bit life also discouraged wide-spread utilization.

1990 Technology:

Improved drilling bit technology and the advent of coiled tubing have combined to overcome several slimhole technology problems. Drilling costs and tubular goods costs have decreased significantly however since the mid-1980s which diminishes the cost savings achievable through slimhole completions. Continued low gas prices are on the other hand cutting into profit margins resulting in some renewed interest.

These opposing factors have kept slimhole work from escalating in significant numbers but they retain the potential for increased utilization.

Result:

Reductions in well costs achievable with slimhole technologies are well documented. Application has been limited to specific conditions. New technology continues to expand the opportunities.

Where:

Slimhole applications are not limited to any single area but lend themselves to low volume production and/or wells where simple completion procedures apply. Continued development of completion procedures applicable in slimhole tubulars, small diameter logging tools and other procedures which allow workovers to be conducted inside small diameter pipe will expand application.

LOG INTERPRETATION IN HORIZONTAL WELLS

Purpose:

Log interpretation has been developed and fully established for conventional vertical wells. However, care must be taken in applying those techniques to high angle and horizontal wells. Reliable log interpretation in such wells can provide information on natural fractures, stratigraphy, and wellbore geometry as well as rock properties and saturations.

How:

Horizontal wells are logged with drill pipe- and coiled tubing-conveyed wireline logging tools, and/or with MWD/LWD (logging while drilling) mud telemetry devices, that produce quantitative and qualitative information on the reservoir formation when properly interpreted.

1975 Technology:

Log interpretation techniques adapted to horizontal wells did not exist in 1975.

1990 Technology:

Proper interpretation techniques for horizontal well logs have been developed only recently. Conventional log interpretation is based on the radial symmetry of the rocks around the wellbore, i.e., the logging tool investigates a uniform material at any one depth. A major (horizontal well) interpretation problem has been overcoming the fact that the rocks around the horizontal wellbore are now asymmetrical, i.e., the log may be influenced by formation layers above and below the wellbore. Techniques have been developed that overcome the asymmetry problem by creating a formation model based on geologic and drilling data and using it to (1) predict a log profile, and (2) compare the actual log to the synthetic one. LWD provides real-time lithologic and saturation data while the well is drilled, as well as giving geologic steering capabilities to the driller.

Result:

Logs of horizontal and high-angle holes can be interpreted to provide reliable lithology and reservoir information.

Where:

Log interpretation techniques tailored for horizontal wells has world-wide application.

References:

SPE 23114. "Recent North Sea Experience in Formation Evaluation of Horizontal Wells," J. White, presented at the 1991 SPE Offshore Europe conference in Aberdeen, Scotland, 3-6 September, 1991.

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EXPERT SYSTEMS/ARTIFICIAL INTELLIGENCE

Purpose:

Office, laboratory, and field operations automation is increasing productivity in all facets of our industry, while reducing technical manpower, experience, and expertise requirements.

How:

Expert systems are computer applications that use explicitly represented knowledge and computational inference techniques to achieve a level of performance comparable to human experts in specific application areas. Artificial intelligence (AI) is computerized decision making or problem solving; i.e., machines containing inherent thought-processing capabilities to reason, learn, and make judgments. The terms "expert systems" and AI are often used interchangeably.

1975 Technology:

AI and expert-type systems were still in the laboratory and had not been applied by the oil and gas industry or commercialized to any extent.

1990 Technology:

Knowledge-based expert systems have exploded into all facets of our industry in the last 10 years. A typical 1990s system is ODDA, a drilling engineering advisor that assist in (1) early well planning, (2) determining optimum well trajectories, (3) during operations, designing BHAs and controlling bit runs, and (4) during the evaluation phase, running statistics and comparing planned and actual results. Other systems include advisors on exploration/geophysics, formation evaluation, log interpretation, production, offshore development, casing and cementing program design, acid treatments, drilling mud rheology, and refining/chemical process engineering. Artificial intelligence development is still primarily in the laboratory, although some AI (pattern recognition and symbolic processing) technology is now being applied in such areas as geophysics, log interpretation, and chemical process control.

Results:

Time-consuming, manual engineering functions such as casing string design are now commonly and quickly performed by expert system-type computer programs, resulting in significant productivity increases.

Where:

Across all sectors of the international oil and gas industry.

References:

Computerized technical and business literature search of COMDEX PLUS and NTIS systems, too many to list.

BARIUM SULFATE AND NORM-CONTAINING SCALE TECHNOLOGY

Purpose:

To reduce the impacts of barium sulfate scales. Problems caused by barium sulfate scales are twofold:

- Production of petroleum may be drastically reduced and require costly well work-overs
- Resulting scale may contain naturally occurring radioactive materials (NORM) that pose a serious disposal problem.

Future barium sulfate scale management technology may improve petroleum production by:

- Preventing formation of barium sulfate scale
- Providing methods to solubilize or remove scale
- Providing innovative methods to dispose of or reuse NORM-containing scale.

1975 Technology:

Scale formation was accepted as unavoidable and mechanical milling procedures were used for removal. Based on well maintenance costs, petroleum production within some basins was uneconomical. The wastes produced by these removal procedures would also be considered unacceptable in today's regulatory environment.

1990 Technology:

Some scale inhibitors have been developed and are readily available from service companies. The effectiveness of existing inhibitors and methods of introducing them into the petroleum recovery facility are questionable, based on input from other major oil companies. Once scale is in place, methods for removal are limited. Milling techniques are an option. Mobil has recently developed a proprietary technique for solubilizing scale from petroleum recovery equipment. Once the scale is removed in solid or solubilized form, disposal or reuse techniques must be rationalized with respect to current regulatory demands. For example, recent work performed by ARCO has demonstrated the potential for reinjecting solid NORM wastes. Mobil has recently obtained permits to inject dissolved NORM waste in Class II wells. New research is needed to identify: (1) new inhibitors and their mechanisms, (2) methods for removing potentially NORM-containing scale, and (3) environmentally safe disposal or reuse techniques.

Result

Improvements in barium sulfate scale management technology will ultimately decrease the cost of producing oil and gas, and provide environmentally safe and economic ways for addressing NORM wastes.

Where:

Studies are being performed to predict areas where scale may form in response to pressure drops induced during production. Places where seawater is commingled with formation fluids (off-shore operations) may also pose a scaling/NORM problem.

AUTOMATION TECHNOLOGY

Purpose:

To utilize microprocessor based equipment to more efficiently and safely monitor and control gas production and processing facilities.

How:

Automation technology permits the use of programmable electronic devices to: (a) gather on-line operational data, (b) optimize production performance, and (c) analyze results for the purpose of managing gas resources better.

1970-1980 Technology:

The emphasis is on hardware and computing power. Modularity, reliability, and robust packaging allow remote areas to be automated. Improved communication techniques (including radio and microwave) permit data to be transmitted long distances. More "efficiency" production operations can be translated into an equivalent gain in natural gas supply.

2000 Speculative Technology:

Advances into more sophisticated software and control strategies will lead to more advanced automation, including applications involving artificial intelligence and neural networks. Communication techniques will be further improved and standardized. The benefits will come from further production efficiency, as well as from the capability to process gas more optimally.

Result:

Improved production and processing efficiencies—leading to an incremental equivalent gain in natural gas supply.

SEISMIC DATA ACQUISITION AND INTERPRETATION

Purpose:

Seismic data acquisition and subsequent interpretation provides a "view" of subsurface stratigraphy normally in two dimensions. The combination of many seismic cross-sections together can provide points of reference for developing subsurface maps of geologic features and can thus discover, define, or refine potential hydrocarbon reservoirs.

How:

Seismic energy is produced normally at the earth's surface and travels at varying velocities through rock layers at various depths. Seismic "reflections" are detected at the surface through geophones. Energy and velocity data is processed by computer to produce a cross-section normally in two dimensions. Data are processed to accurately depict proper subsurface depth and location along the seismic line. Normally, many of these cross sections are studied in a given area and correlative subsurface points are spotted on a flat map. Subsurface contours are drawn connecting points of equal depth producing a map of subsurface structures and anomalies. The mapping of large structures (square miles in size) to the mapping of small channel sands have been accomplished using this basic technique.

1975 Technology:

Less than 96 recording channels using analog and digital techniques. Geophone array length of 80 to 390 feet. Simple datum statics. Laboratory processing. Limited ability to focus on specific geologic features or strata.

1990 Technology:

The idea of initiating and then recording seismic energy for the purpose of defining subsurface stratigraphy is not a new one. What has changed, particularly from the 1980s to present, is the processing and subsequent interpretation techniques applied to subsurface studies utilizing seismic data and sophisticated computers. Absolute improvements in all phases of two dimensional seismic data acquisition and the addition of three dimensional seismic acquisition and interpretation. The combination of higher energy frequency detection, geophone improvements and processing breakthroughs have permitted very specific evaluation and detection of thin geologic units. Recording channels now number up to 1,000 using digital technologies. Processing techniques include field processing and the integration of computer centered work stations. Two dimensional cross-sections can now be expanded to three dimensional cut-outs of a larger geologic feature. Presentations now include color graphics for seismic display with the ability to tilt, rotate, or view from any angle a three dimensional model of geologic features.

Result:

Improved seismic techniques are defining hydrocarbon accumulations in many U.S. basins, onshore and offshore. For example, new seismic techniques have helped to identify 850 BCF of natural gas in the geologically complex Arkoma basin of southeastern Oklahoma.

Where:

Improved 2D seismic techniques are pervasive throughout the exploration and production segments of the petroleum industry. Three dimensional seismic techniques are becoming commonplace and have been used effectively in the Gulf of Mexico, Arkoma basin, and south Texas.

HORIZONTAL DRILLING

Purpose:

Normal well completions are drilled at near vertical. This limits contact between the well bore and the productive formation. Horizontal completions intersect more of the productive zone to the wellbore and more specifically can expose additional reservoir features such as vertical fractures to the well bore to enhance the productivity of a single well. This technique significantly influences drainage areas associated with individual wells, also.

How:

A horizontal well is normally drilled vertically to an intermediate depth then "kicked" in a predetermined direction. The radius of the curve from vertical to horizontal can be short, medium, or long. The angle is built until intersection with target formation, then the well is drilled parallel to bedding surfaces and often perpendicular to features such as vertical fractures. It is the intersection of the wellbore with more of the target reservoir or features of the reservoir (such as permeability enhancing fractures) that improve the production characteristics of the reservoir.

1975 Technology:

Early use of downhole motors with separate use of steering tools and singleshot directional surveys required that large amounts of rig time be used for trips to change equipment. Directional surveys required that drilling be ceased and the survey tool be lowered into the hole. Limited equipment accuracy often resulted in a wellbore which oscillated around the proposed directional line.

1990 Technology:

Major advances in horizontal drilling include the use of steerable motor assemblies (SMAs) and measurement while drilling (MWD) survey and logging tools. One assembly can now be used to build the angle of drilling toward horizontal significantly reducing idle rig time and trip time for changing assemblies. The combination of measurement while drilling techniques and polycrystalline-diamond-compact bits (PDCs) has further increased the ability of one assembly to cut a large portion of the horizontal hole without tripping to replace equipment. Directional control is also enhanced by MWD techniques. Drillstring designs have been optimized to reduce torque and drag and improve the transfer of weight to the drill bit. Record true vertical depth for a horizontal well is 14,672 feet in Huxford Field, Escambia County, Alabama.

Result:

Horizontal wells are being drilled in formations particularly where the increased intersection of the well bore with a geologic feature such as vertical fractures is desirable. Improvements in producibility are documented in plays such as the Austin Chalk of South Texas. Since 1989, 41 horizontal wells in the Austin Chalk have added 42 million net equivalent barrels of proved reserves.

Where:

West Virginia (Devonian shales), Michigan (Antrim shales and Niagaran reef structures), North Dakota and Montana (Bakken shale), Wyoming and Colorado (Cretaceous Niobrara), New Mexico (San Juan Basin), South Texas (Austin chalk), Gulf of Mexico, Alabama (Huxford field).

POLYCRYSTALLINE-DIAMOND-COMPACT (PDC) DRILL BITS

Purpose:

To improve longevity and versatility of drill bits in a variety of drilling environments.

How:

Drill bits are secured at the bottom of the drill string. Teeth on the bit cut and grate rock either by being rotated by the drill string or rotated by a downhole motor.

1975 Technology:

The most precise way to discuss the evolving technology of bits is to focus on an example area. The Wilcox trend of south Texas in Webb and Zapata counties have been extensively drilled since the 1970s and 1980s. Mid-1970s drilling required 5 to 6 milled tooth bits and 4 to 5 tungsten-carbon insert roller core bits working approximately 15 days (for drilling and tripping) to complete a 10,000 foot well. Bits were cone shaped with holes for jetting drilling fluid to circulate cuttings up the hole and 3 rollers oriented on the end of the bit with various tooth shapes and lengths for cutting various rocks. Each bit change required tripping the entire drillstring out of the well to access and change the bit.

1990 Technology:

The same 10,000 foot well can now be drilled using 1 milled tooth bit, 1 tungsten-carbon bit and 2 PDC bits. This combination requires 7 days to drill to total depth (half the time of 1975 drill bit technology). The PDC bits can even be reused on other wells. Each PDC bit cuts a greater variety of rock, maintains its cutting capability longer and thus requires less rig time for tripping and changing bits.

Where:

PDC bits are utilized throughout the drilling industry today. PDC bits are estimated to serve 23 percent of total bit needs in the petroleum industry (Salomon Brothers, Oil Service Monthly, May 1990).

Technology References:

Journal of Petroleum Technology, "Status of Polycrystalline-Diamond-Compact Bits: Part 2 Applications," R. Feenstra, July 1988.

> This discussion focuses on the practical applications for PDC bits including use in depleted reservoirs, directional or deviated drilling, slim and large-hole drilling, underreaming and coring. For example, compared to conventional drill bits, PDC bits drill up to five times faster when coring thus reducing formation invasion and damage.

Journal of Petroleum Technology, "Status of Polycrystalline-Diamond-Compact Bits: Part 1 – Development," R. Feenstra, June 1988.

> This article discusses the characteristics of PDC bits including temperature during drilling and impact resistance, as well as bit design and the future of PDC bit development.

Ocean Industry, "How Six Oil Companies Rank Offshore Technology Advances," Robert E. Snyder, April/May 1990.

> This article reviews the major technical improvements in offshore operations during the past decade. Specifically, Robert L. Bailey (Chief Engineer of Chevron) states, "PDC bits have made single runs from casing point to casing point possible. When used in conjunction with steerable drilling systems, PDC bits are particularly valuable."

TENSION-LEG WELL PLATFORMS (TLWP)

Purpose:

To replace solid-leg structures for deepwater production facilities.

How:

A tension-leg structure is connected to the seabed by vertical tubular steel mooring lines. The buoyancy of the platform at the surface creates an upward force, keeping the legs under tension and causing the platform to float in place.

1975 Technology:

During the mid-1970s solid offshore structures were routinely set in hundreds of feet of water. Stretching the limits of solid-structure technology was an economic issue. Sufficient reserves were required to cover substantial dollar investments in large offshore structures.

1990 Technology:

By 1989, Shell had set its rigid-structure Bullwinkle platform in the Gulf of Mexico in a water depth exceeding 1,350 feet. However, deeper water production facilities were needed. The tension-leg well platform offers significant economic advantages. The TLWP set at Jolliet field in the Gulf of Mexico by Conoco required only 12,000 tons of steel (including mooring lines and foundations) versus 80,000 tons for a rigid structure in the same 1,760 feet water depth. Wells are drilled by a semisubmersible rig, then seafloor completions are tied back to the production platform as satellite locations through flow lines.

Result:

Production technologies such as tension-leg well platforms have dramatically increased the water depth for economically recoverable reserves. Such advances have influenced the view of estimated resources in deepwater, also. For example, at year-end 1986 The Potential Gas Committee (PGC) offered no resource estimate for offshore areas in more than 1,000 meters of water. However, at year-end 1988 the PGC estimated 30 Tcf of gas resources in the Gulf of Mexico located in water depths exceeding 1,000 meters. Such estimates have been made under the influence of all production technology advances which have opened the door to deepwater development of gas resources.

Where:

This technology was applied first in the North Sea and is now a viable option for deepwater Gulf of Mexico operators.

GEOGRAPHIC INFORMATION SYSTEMS

Purpose:

Explorationists need to analyze many types of data concurrently to decide about lease acquisition, whether or not to drill, and drill location if the decision is yes. Software and data sets to analyze digitally this spatial data will promote better decisions by bringing more information to the problem, provide more analytic capability, and try more different alternative interpretations.

How:

Geographic Information Systems (GIS) combine vector and raster data in two dimensional overlays. For example, one can estimate the favorability of plays in a basin by digitally combining:

- For source: kerogen type, thickness, expulsion efficiency, thermal history, total organic content
- For migration: thickness and migration efficiency parameters
- For play: trap type favorability, reservoir thickness, and seal parameters.

1990 Technology:

Data is input with great difficulty. No systems adequately combine raster with vector data or analyze a three-dimensional model. GIS is used by some of the majors in relatively unique circumstances.

2000 Speculative Technology:

Combining raster with vector information and will be routine. Analyzing three-dimensional data sets will be new. Spatial data will be collected to fit into a GIS with relative ease. Data libraries will exist to use data multiple times.

Result:

Improved geographic analysis will improve the efficiency of many of the exploration and production operations. Each professional will be more productive in his/her analysis.

WATER SHUT-OFF USING POLYMERS

Purpose:

Water coning and fingering in high permeability intervals can cause premature abandonment of reserves. Operators have had mixed results using polymers to shut off unwanted water production. A thorough understanding of polymer performance in specific applications can improve polymer selection for water shut-off and lead to the development of improved polymers for this application.

How:

Polymers are injected into reservoirs having unwanted water production. The polymers are designed to set in specific conditions such as high salinity so that watered out intervals will be plugged off while allowing hydrocarbon bearing intervals to produce.

1990 Technology:

Polymers have been developed to shut off water production. However, often the polymer characteristics are not understood well enough to apply the right polymer in the right application. In other cases no polymer has been identified or developed to fit a necessary application. The result is a very low success rate for these treatments.

2000 Speculative Technology:

Laboratory and field research will increase knowledge of the characteristics of existing polymers and lead to the development of new polymers so that water shut-off can be routinely performed with a high success rate.

Result:

Improved success rate for water shut-off treatments will decrease premature abandonment of reservoirs because of excessive water production.

GEOPRESSURED GAS RESERVES PREDICTION

Purpose:

In normally pressured gas reservoirs, reserves can be estimated graphically by plotting reservoir pressure versus gas production. In abnormally pressured reservoirs this graphical representation is complicated by changing rock compressibility and reservoir compaction. Accurate representation and extrapolation of the data are necessary to estimate reserves accurately.

How:

Rock properties must be measured accurately and the effects of changing reservoir pressure on these properties must be understood and quantified.

1975 Technology:

The effects of changing rock compressibility and reservoir compaction were not determined accurately. Often these properties were empirically estimated using a technique that tends to underestimate both the gas in place and the ultimate recovery. Even when the properties were measured, rather than empirically estimated, the measurements were not accurate. The measurements were determined using hydrostatic loading.

1990 Technology:

Changing rock compressibility and reservoir compaction with decrease in reservoir pressure can be measured accurately. Uniaxial loading with no radial displacement much more accurately represents true reservoir stresses than the previously used hydrostatic loading. The measured rock properties are easily incorporated into the estimation of reserves.

Result:

Accurate rock compressibility measurements are showing more initial gas in place in many geopressured gas reservoirs. Also, accurate measurements of rock compaction are showing that several geopressured reservoirs can, in fact, be depleted to much lower pressures than originally expected. The effect of both of these findings is higher reserve estimates for many geopressured gas reservoirs.

Where:

South Texas (Wilcox), Gulf of Mexico, South Louisiana.

FORMATION DAMAGE CONTROL

Purpose:

Formation damage can occur at any time in the life of a well—during drilling, completion, production, and/or injection. Formation damage reduces the reservoir permeability in the damaged region and, thus, can severely restrict productivity. Damage to an exploratory well during drilling or completion can mask productivity such that a discovery goes unrecognized. Damage to a producer or injector can also cause premature rate decline below the economic production limit and, thus, premature abandonment of reserves. A complete understanding of the mechanisms of formation damage can enable the engineer either to avoid or to remedy the damage.

How:

Using an understanding of fluid/fluid and rock/fluid interactions, both chemical and mechanical, an engineer can design drilling, completion, and injection fluids as well as drilling, completion, production, and injection procedures to minimize the damage. The engineer can also apply this same understanding in identifying and removing damage that has already occurred.

1975 Technology:

Relatively few options existed for drilling and completion fluids. "Hardy" reservoirs that were not severely damaged by using these fluids were plentiful and more sensitive reservoirs were most likely tested and bypassed. Fines migration was not well understood and was usually ignored or discounted.

1990 Technology:

"Hardy" reservoirs are now the exception and sensitive reservoirs are the rule. Customized non-damaging drilling and completion fluids exist and are routinely used to ensure fluid/fluid and rock/fluid compatibility. Geochemical computer models are used to predict chemical reactions between reservoir rocks and injected fluids. Fines migration models exist and are being improved to predict reservoir particle movement caused by chemical and mechanical influences.

Result:

Formation damage control is now an integral and routine part of an engineer's drilling, completion, production, and injection planning and design. Productivity has improved and sensitive formations can now produce in commercial quantities.

Where:

Everywhere. For example: South Texas (Wilcox, Austin chalk, Vicksburg), New Mexico (San Juan Basin), Gulf of Mexico.

CORROSION RESISTANT ALLOYS FOR DEEP, HOT, SOUR GAS WELLS

Purpose:

Typical gas well completions involve the use of carbon or low alloy steel materials. Corrosion inhibitors, nonmetallic coatings or both may be used for corrosion protection. Deep, hot sour gas wells require stronger, more environmental cracking resistant materials than typical gas wells. Also, deep, hot sour gas wells are much more corrosive than typical gas wells. Common corrosion inhibitor materials and delivery methods won't work. A solution is to use corrosion resistant alloy (CRA) materials for tubing, wellhead and christmas tree components and even casing. Corrosion inhibitors and coatings are not needed with CRAs.

How:

CRAs are selected for downhole and surface completion equipment. These metals have sufficient strength and can withstand the high downhole temperatures. They resist corrosion from CO_2, H_2S, Cl- and elemental sulfur. Also, they do not crack in the produced fluids.

1990 Technology:

CRAs are used for tubulars, downhole tools, and wellhead components. In order of increasing resistance to the environment and increasing cost, the most common materials include duplex stainless steels, high nickel content iron based austenitic alloys, and nickel based alloys. Titianium alloys have been considered for some applications. Surface piping can be either solid CRA or carbon steel pipe internally clad or lined with CRA (so called bimetallic pipe). Fittings are solid CRA. Valve bodies are carbon or alloy steel internally clad with CRA. The CRA is applied by welding or through a powder metallurgy process.

2000 Speculative Technology:

Metal matrix composites, ceramics, ceramic composites will likely be available, particularly for valve and downhole tool components.

Result:

Extremely corrosive gas reservoirs can be produced reliably with no corrosion inhibitor and minimal corrosion-related well workovers. Expensive completion materials dictate a high gas price (or ready sulfur market) to allow economical gas production.

COALBED METHANE PRODUCTION TECHNOLOGY

Purpose:

To produce natural gas (essentially methane) associated with coal seams. Most of gas production comes from sandstone-type reservoirs where the gas exists in the pores between the rock grains. In coal seams, gas is adsorbed on the surface of the coal. The amount of gas present increases with the pressure. As the pressure is decreased, gas desorbs from the coal surface and can then be produced.

How:

Initially, coal beds are immersed in water. They are highly fractured. Usually two sets of fractures exist. A major set of fractures (called cleats) is called face cleats. A minor set of cleats (usually perpendicular to the face cleats) is called butt cleats. When a well is put on production, water only is produced. As the pressure declines, gas desorbs from the coal surface to maintain equilibrium under the new pressure. Gas then diffuses through the coal to the cleats and flows to the producing wells. At first, the gas production rate is small and may be zero. As the gas saturation in the deats increase, the gas production rate also increases, then as gas is depleted, the rate declines.

1975 Technology:

The process of producing methane from coal seams was not understood. Coal degasification lacked the knowledge of proper well completion, production techniques and reservoir engineering necessary to effectively and economically produce these reserves. Gas production from coal seams was practically non-existent.

1990 Technology:

Methods to quantify the gas content of coal seams were developed. Unlike conventional gas reservoirs, where the pore volume and reservoir pressure are sufficient to indicate the gas in place, experiments must be run on coal samples to find out how much gas will be produced at a given pressure. Completion technology for coal degasification wells matured. Without a form of stimulation, gas cannot be produced. Two completion methods were developed and are widely used today. Fracturing or cavitation is employed on all wells. Although some questions still exist for both techniques, results can be predicted with sufficient reliability. Experience with well logs reached the point where practicing engineers know what to use in evaluating coal beds. New pressure transient methods, based on the concept of multiphase pseudo pressure analysis, were developed to characterize coal beds. Reservoir simulators that take into account the adsorption, as well as the Darcy law flow, were developed to help predict the reservoir performance under a variety of operating strategies.

Results:

The combination of all these new technologies resulted in a substantial gas production capacity. Two major basins in the United States are sites for coal bed methane projects. The San Juan Basin in Colorado and New Mexico had about 700 gas producing wells from coal seams by 1990. Its production is estimated at 250 BCF annually. The Black Warrior Basin in Alabama had about 1,200 wells in 1990 producing 24 BCF annually.

Where:

Several basins in the Rocky Mountain area and the Eastern United States.

HYDRAULIC FRACTURE DIAGNOSTICS—GEOMETRY MEASUREMENT

Purpose:

The most direct evaluation of a hydraulic fracturing treatment is the measurement of the geometry of the created fracture in the reservoir. With the information obtained in these measurements, engineers can optimize the fracturing design to best exploit the reservoir potential and to achieve higher productivity while maintaining a low treatment cost.

How:

The techniques being used in the industry or having the potential to be used in the future for fracture geometry measurement are:

- Temperature log;
- Radioactive tracer log;
- Triaxial borehole seismic, microseismic log and other seismic techniques;
- Tiltmeter array mapping;
- Hydraulic impedance and other borehole acoustic techniques;
- Borehole radar or other electrical magnetic wave techniques; and potentially many others.

1990 Technology:

The temperature logging and the radioactive tracer logging are currently the most mature techniques. However, they are limited to the measurement of fracture height at the wellbore, and the interpretations are often ambiguous. The inferred height is not correct if fracture plane departs from wellbore, a frequent occurrence for a deviated wellbore. Tiltmeter mapping is limited to shallow depth. The hydraulic impedance and borehole radar techniques are still at primitive stages. The most promising techniques for full fracture plane mapping are the microseismic techniques. Many field tests have been tried and were successful. However, there are still some difficulties in detecting seismic signals from far distances, leaving insufficient analyzable seismic events to fully define fracture boundary.

2000 Speculative Technology:

Improved microseismic tools for commercial utilization provide sufficient resolution and background noise filtering mechanism to detect weak seismic signals for an accurate determination of hydraulic fracture plane.

Results:

Engineers will be provided with a direct tool for evaluating fracturing treatments. The optimization of fracture design can be more easily achieved than the trial-and-error process currently being exercised. The result is the maximum well productivity with the minimum cost.

FULLY 3-D FRAC MODEL—REAL TIME CONTROL

Purpose:

Hydraulic fracturing stimulation treatments can significantly increase drainage area and gas well productivity. Real time 3-D frac modeling and control will incorporate treating conditions, rheological data, and formation bottomhole pressure response into an accurate model for predicting the fracture geometry being created and direct changes in the treatment procedure to achieve optimal stimulation.

How:

Real Time Fully 3-D Frac Modeling and Control will combine the real time data acquisition and analysis of:

> Fracturing treatment conditions such as fluid and additive rates, surface pressures and slurry densities
>
> Fracturing fluid rheological properties such as base gel and crosslinked slurry viscosity
>
> Formation bottomhole net pressure response to height growth, fluid leakoff and changes in slurry rate and viscosity

into a fully 3-D non-planer, finite element fracture simulator with 3-D fluid flow and proppant transport to determine the fracture geometry being created and directly control the treatment conditions to achieve an optimal fracture penetration and conductivity for the formation at hand and the materials available.

1990 Technology:

Real time display of formation net pressure trends to infer a fracture propagation geometry using surface treating pressures and approximations of fluid friction pressures to estimate actual bottomhole pressure. Post-treatment pseudo 3-D modeling of the approximate fracture geometry created.

2000 Speculative Technology:

Real time direct measurement of bottomhole pressure and improved fracture simulators combined with process control equipment to fully automate the hydraulic fracturing treatment.

Results:

Optimal fracture penetration and conductivity reduces treatment cost while increasing drainage area, ultimate recovery and well productivity.

GEOCHEMICAL/ACIDIZING MODEL

Purpose:

To model the interaction between the complex mineralogy of a formation and the acids used in matrix stimulation treatments. Such a model would predict the production increase from an acid treatment and determine the type, concentration, and volume of acid to pump in the treatment. The model would be used to optimize matrix acidizing treatments by providing the most cost effective treatment. Since matrix acidizing provides a higher return on the stimulation dollar than any other type of stimulation, a Geochemical/Acidizing model can be an economic tool in the overall management of a reservoir.

How:

A Geochemical/Acidizing model utilizes known rock properties such as bulk and clay mineralogy, reaction kinetics, and formation temperature to predict changes in permeability, porosity, and skin as acid is pumped into the wellbore. Variables such as acid strength, volume, or concentration will effect changes in permeability, porosity, and skin. By altering these variables the model can determine the optimum matrix treatment necessary to give maximum production.

1970 Technology:

Geochemical/Acidizing models were nonexistent in 1970. Foundational work such as reaction kinetics, stoichiometry and equilibrium relationships were just being established. Most early work was done with individual rock components and not on whole rock. The first models incorporating different physical and chemical variables were presented in the late 1980s.

1990 Technology:

Although much more needs to be learned about the reaction of acid with a sandstone formation, recent models have made progress toward predicting the effect of an acid treatment in a well. Attempts are now being made to correlate model predictions with laboratory core flow studies. Work remains to be done on correlating model predictions and recommendations with field treatments. Pragmatic application of Geochemical/Acid models is still 5-10 years in the future. Geochemical/Acid modeling is at the stage that hydraulic fracturing was 20 years ago.

Future Technology:

Geochemical/Acidizing models will utilize information from a variety of sources (core analysis, rock properties, log analysis, drilling records, production history) to identify sources of formation damage and reasons for production decline. The models will then determine an appropriate acid system along with the proper volume, concentration, additives, and pumping method to restore productivity. The models will predict changes in permeability and porosity at various distances from the wellbore and the impact that this will have on productivity. Future models will optimize acid treatments by determining the most cost effective treatment that will have the greatest impact on productivity.

Result:

A great deal of progress has been made with Geochemical/Acid modeling. Current models will predict changes in permeability, porosity, and depth of acid penetration. Validation of these models with either field treatments or laboratory testing has not been achieved. Recognition of the complexity of the acid/formation interaction is leading to the research necessary to improve and expand the models used today.

Where:

Since the majority of the world's oil and gas supply is found in sandstone formations Geochemical/Acid modeling can play a significant role in recovering that oil and gas. In the past acidizing has taken a backseat to hydraulic fracturing in the stimulation arena. Acid treatments can be pumped at much lower costs than hydraulic fracturing treatments and by using a tool like a Geochemical/Acid model a much higher return on the stimulation dollar can be achieved.

HORIZONTAL WELL STIMULATION

Purpose:

There are few limitations in drilling a horizontal well with today's technology. Horizontal wells are now being applied to poor reservoir rock that needs a stimulation to produce. When successful, uneconomical reserves become successful by increasing the productivity of the well. Current stimulation technology uses the same tools and techniques of a vertical well which become costly in a horizontal well. These techniques are hydraulic fracturing, and acidizing. Because of the cost associated with the stimulation, compromises are made limiting potential rate and reserves benefits.

How:

Stimulation in a horizontal well is achieved by pumping a propped hydraulic fracture, acid washing using coiled tubing, water washes, and acid fracturing treatments using chemical diverters or mechanical isolation tools. All these techniques are limited to treating a small area of the wellbore because of the large intervals. Proper diversion is critical for a successful stimulation but becomes very costly.

1975 Technology:

Because of the equipment accuracy of drilling a horizontal well, stimulation was limited to pumping fluid down the tubulars with the hope that the damage will be removed. Coiled tubing during this time was unheard of because of the number of failures that were associated with using it.

1990 Technology:

Advances in coiled tubing and downhole equipment has resulted in applying vertical stimulation technology to horizontal wells. Downhole shut off tools are able to reduce the area to be treated thus enabling a better stimulation. Polymer gels and foam are being used for diversion in open hole configurations. These improvements in pumping and placement of stimulation fluids are still influenced with cost and reliability to perform correctly.

Future Technology:

Development of larger and dual coiled tubing strings will improve the reliability of downhole equipment. Future downhole equipment will be operated through hydraulic inner work strings increasing the capability of the tools. Better understanding of how diverting materials work will lead to better efficiency of diverting stimulation fluids in the wellbore. Improving the placement of the stimulation will result in the most cost effective treatment that will have the greatest impact on the wells productivity.

Result:

Improvements in the wells productivity through stimulation are documented throughout the industry. The Austin chalk area has been one of the leaders in developing these technologies because of the increase in drilling horizontal wells in this area. Technology gains are also being seen in the north slope from their highly deviated wellbores through perforating and tool development.

Where:

Horizontal wells are drilled everywhere today and are not limited to one area as in the past. The greatest activity today is still in the Austin Chalk and Devonian shales but activity is on the rise on the North Slope where limited drilling pads are forcing higher angle reach wells.

HIGH TEMPERATURE CEMENTING TECHNOLOGY

Purpose:

To improve primary cementing in a variety of high temperature operations, i.e., deep gas or oil, geothermal, steam flood, etc.

How:

Through increased understanding of the effects of elevated temperatures on cement slurries and set cements, and the development of (1) thermally stable cement formulations, (2) highly functional and predictable cementing additives, and (3) more accurate tools and methods for measuring downhole temperatures.

1975 Technology:

The use of additional silica (sand or flour) to stabilize the calcium (lime):silicate ratios in Portland cement at temperatures above 230°F has been practiced for over 15 years. Thermally stable cements such as Classes E, D, J (high aluminate cement) and Lime:Pozzolan blends have been used throughout the industry, but with varying success. A limited number of functional and predictable cementing additives are available to (1) regulate pumping times, (2) control fluid loss, (3) provide uniform compressive strength development throughout the length of the cemented interval, and (4) minimize W.O.C. (Waiting-On-Cement) time at elevated temperatures. In addition, lab studies have shown that a 25°F variance in temperature can shorten the thickening time for a cement slurry by as much as 50 percent, or double it. However, accurate and economical downhole temperature measuring devices are virtually non-existent. Due to these limiting factors, primary cementing success rates in deep, hot wells are lower than desired; the number of "cemented up" wells are excessive; remedial cementing costs are high; and rig costs, due to wasted W.O.C. time, are too expensive.

1990 Technology:

A wide variety of high temperature additives and special formulations have been developed which provide consistent performance and greater control over cement slurry properties and set cement behavior at elevated temperatures. These new developments have allowed Class G and H oil well cements to be applied at temperatures in excess of 450°F, yielding better quality control, and obsoleting most of the thermal cement formulations. Increased knowledge of the chemical and physical reactions in cement at elevated temperatures, coupled with new technologies capable of controlling or modifying these reactions, have greatly improved primary cementing success rates. Pumping times and transition periods for cement slurries can be optimized, slurry dehydration and fluid loss can be regulated, compressive strength development and thermal stability can be controlled, and W.O.C. times can be reduced in many cases by as much as 70 percent. In addition, accurate downhole temperature measuring devices and computer simulators have been developed which have further optimized the design and displacement processes. Advancements in high temperature cementing technology within the past 10 years have greatly improved primary cementing success rates, reduced remedial applications, and helped to decrease rig costs.

Where:

Major service companies now offer extensive product lines and a variety of "state-of-the-art" cementing formulations for high temperature applications on a global scale.

Technology References:

The volume of technical publications on high temperature cementing applications, products, and systems over the past 10 years is tremendous. Only a few articles have been referenced to support the above summaries:

Drilling, "Cementing at 30,000 Ft.," B. B. Bradford, July 1982.

This article summarizes the amount of detail that has to go into a cementing design at these extreme conditions, and points out some of the advantages of modern day technology.

Journal of Petroleum Technology, "High-Temperature Cement Compositions—Pectolite, Scawtite, Truscottite, or Xonotlite: Which Do You Want?" L. H. Eilers, E. B. Nelson, L. K Moran, July 1983.

A broader based knowledge of cementing compositions at elevated temperatures and a means of controlling the setting process to develop desired set cement properties.

No. 84-35-115, "Evaluation and Improving Thermal Cementing Practices," W. Chmilowski, A. Frankiw, R. J. Ford, 1984 Annual Petroleum Society of CIM, June 1984.

This paper summarizes some of the advanced evaluation and design procedures for improving cementing applications in high temperature wells.

SPE 12454, "Geothermal Well Cementing Technology," S. H. Shryock, 1984 SPE Offshore South East Asia conference, Feb. 1984.

Presents a summary of the new advances in cementing formulations for extreme temperature applications.

SPE 18029, "Improved Circulating Temperature Correlations for Cementing," M. A. Goodman, et al., 1988 SPE Annual Technical Conference and Exhibition, Oct. 1988.

Illustrates new computer simulated correlations to provide more accurate downhole temperatures to enhance cementing designs and applications.

Journal of Petroleum Technology, "New Cement Formulation Helps Solve Deep Cementing Problems," L. E. Brothers, F. X. deBlanc, June 1989.

This article discusses some of the problems associated with formulating a cement system for high temperature applications, and introduces a synthetic polymer product which provides dispersion, retardation and fluid loss control in cement slurries.

LOW DENSITY CEMENTING TECHNOLOGY

Purpose:

To decrease hydrostatic pressures on weak or unconsolidated formations during cementing operations while, at the same time, provide a cement which will support and protect the casing, isolate production intervals, and meet federal and state regulations.

How:

Through the use of lightweight fillers, chemical extenders, or special additives which allow excess water or gas to be added to a cement slurry and reduce the slurry density while providing desirable cement properties.

1975 Technology:

Basically, the same extenders (fillers) have been used for many years. These consist of (1) reactive materials (organic clays (bentonite, attapulgite, etc.), polymers, and silicates), (2) inert fillers (gilsonite, mica flake, diatomaceous earth, pozzolans, etc.) and other additives such as expanded perlites (volcanic ash), cellophanes, and plastics. The minimum slurry density that can be obtained using any combination of these materials, and still provide desirable slurry properties, is about 11.5 lbs/gal. Although beneficial, these systems can not consistently solve critical cementing problems such as (1) primary cementing in an air drilled well, or one that won't support a column of water, (2) lost circulation across very weak or highly fractured zones, (3) free water separation or gravitational exchange in deviated wellbores or (4) low density primary cementing. Requirements for primary cements are typically 500 psi compressive strength development in 8 hours, and +2000 psi in 24-48 hours. Most of these extended systems fall to meet these requirements which necessitates the use of a conventional "tail-in" cement slurries in most applications. Special preblended lightweight cement formulations are available on the market, however, they have about the same limitations as systems formulated with the available filler materials. New technology involving the use of gas impregnated or foamed cements is appearing in the industry, but the technology is far from being developed and is very difficult to apply.

1990 Technology:

Foamed cementing technology has undergone tremendous development over the past 10 years. Systems can be designed at densities below 8.3 lbs/gal and are capable of developing adequate compressive strength to support and protect casting. Engineering design and application is a fairly complex process, however, techniques, products and equipment necessary to perform foamed cement applications is constantly improving. In addition, new high strength, ultra-low density filler materials such as high strength, micro-sized hollow glass beads and ceramic or pozzolan spheres have been introduced. Systems can now be formulated at densities as low as 9.5 lbs/gal, and develop greater than 2,000 psi compressive strength in 24 hours with these materials. Either foamed or micro-sphere cements can be used in primary cementations and meet federal and state regulations (Texas Railroad Commission, etc.). Most of the lost circulation and other problems prevalent in 1975 can be solved with these new technologies. This has improved primary cementing success rates and made underbalanced completions and horizontal drilling operations much more cost effective. In addition, these systems have eliminated many of the costs associated with mixing and pumping two (or more) cement systems per job, running stage tools and other specialized hardware in the wellbore, and remedial (squeeze) applications.

Where:

Foamed cement technology and microspheres are used in critical, ultra lightweight cementing applications all over the world.

Technology References:

No. 75-PET-10, "Strength, Permeabilities, and Porosity of Oilwell Foam Cement," C. H. Aldrich, B. J. Mitchell, 1975 Annual ASME Petroleum Division of Mechanical Engineering Conference.

SPE 11204, "Foamed Cement—Solving Old Problems With a New Technique," O. G. Benge, L. B. Spangle, C. W. Sauer, 1982 SPE Annual Technical Conference and Exhibition.

SPE 12755, "Cementing of Fragile-Formation Wells With Foamed Cement Slurries," W. M. Harms, J. S. Febus, 1984 SPE California Regional Meeting.

SPE 19935, "Foamed Cement Characterization Under Downhole Conditions and Its Impact on Job Design," J. de Rozieres, R. F. Ferriere, 1990 IADC/SPE Drilling Conference.

These publications, and many others, summarize the evolution and versatility of foam cements. Ongoing research in foam cementing technology continues to produce formulations with increasingly better properties that are highly cost effective.

Journal of Petroleum Technology, "A New Ultra-Lightweight Cement with Super Strength," T. A. Dobkins, C. A. Powers, R. C. Smith, August 1980.

Presents studies to show the merits of using high strength, hollow glass bubbles to produce a very low density cement slurry which has superior compressive strength to comparative systems.

SPE Production Engineering, "Field Performance of Ultra-lightweight Cement Slurry Compositions Used in the UAE," B. N. Murali, C. H. Tanner, August 1987.

"Horizontal Cementing—Design and Displacement Practices for Higher Success Rates and Reduced Costs," R. R. Jones, Third International Conference on Horizontal Well Technology, Nov. 1991.

These publications illustrate the use of ceramic micro spheres to produce a high strength, lightweight cement with inherently better set cement properties than foam cements, and higher cost efficiency than glass bubbles.

MEASUREMENTS-WHILE-DRILLING (MWD) TECHNOLOGY

Purpose:

To improve drilling control, safety, and efficiency to reduce costs.

How:

Use a downhole system which measures drilling and formation parameters near the bottom of the hole while drilling and either transmits the measured data to the surface in real-time or records the data and retrieves it later to aid in drilling operations and formation evaluation. Perhaps more accurate name for this technology is DMWD (Downhole Measurements-While-Drilling).

1975 Technology:

Deeper drilling, increased activity in offshore directional wells, and rapidly escalating costs have focused attention on all possible methods of drilling safer and cheaper. Real-time data from the bit, if it is possible, give drilling engineer a better understanding of downhole conditions, exert closer control over their operations and offer the greatest potential for meeting these needs. For example, directional survey and control of the hole can only be made with wireline steering tools. But this is an after-the-fact measurement and requires significant interruption of the drilling process. There are no systems for navigation of the bit while drilling. Also, wireline logging is the single most important means of identifying and evaluating formations penetrated by the bit. This, too, is an after-the-fact measurement, which takes place after drilling a section of hole and removing the drill pipe from the hole. Under certain hostile drilling conditions, the wireline logging becomes very expensive or even impossible. In such circumstances, real-time formation logging, if it is available, could save tremendous drilling cost and even become the only log available for the well.

1990 Technology:

MWD technology has matured from an experimental project in the 70s to an essential drilling and exploration tool. Improved MWD tool reliability has made MWD real-time directional survey and control a standard practice for both offshore and onshore directional drilling. Though the savings of MWD real-time directional tool vary depending on the jobs, overall reduction of 20 percent in directional service cost is in common. In addition to the sensors for directional survey, the MWD string continues to undergo upgrading as formation evaluation and other drilling-related measurements develop and become more available. Formation Evaluation-While-Drilling (FEWD), also called DLWD (Downhole Logging-While-Drilling), provides geological data on downhole formation much like conventional wireline logging. These data may be used both to enhance overall drilling efficiency and to evaluate the hydrocarbon production potential of the formation encountered. More recent addition of neutron and density sensors to FEWD equipment containing resistivity and gamma ray measurements, the backbone of wireline logging, the "triple combo," can now be provided in real-time or recorded downhole while drilling. With this capability, FEWD could fully satisfy logging requirements in many situations. Now intermediate or correlation wireline logs can be replaced, openhole wireline logs can also be eliminated to some extent. The benefit and cost saving of MWD technology are getting greater and greater.

Where:

MWD technology is utilized throughout the drilling industry, especially in the areas where long-reach directional and horizontal drilling are required. The worldwide MWD market expanded by 48 percent, rising from $250 MM in 1989 to $370 MM in 1990. In the near term, the focus of MWD development will be on formation evaluation, but other tools and controls related to drilling efficiency will be developed as well.

Technology References:

Oil and Gas Journal, "MWD: State of the art," 10 articles, March 27–July 31, 1978.

This series of articles includes the information on each MWD system being developed in 1970s, together with economic and technical overviews. Each manufacturer contributes technical information on its system and estimates when its tools will become commercial.

Petroleum Engineer International, "MWD Systems Expand Capabilities," May 1991.

This is an annual survey describing all available MWD tools and their operational considerations. A most updated, comprehensive MWD Systems Comparison Table is provided for cross-reference.

Oil and Gas Journal, "Growth in the measurement-while-drilling sector continues," Gordon T. Hall, September 16, 1991.

This article points out that MWD services are on the rise in spite of slowing rig activity. MWD profits have been boosted by increased international activity, its success in horizontal drilling, and the development of formation evaluation tools. Market growth is estimated to be greater than 20 percent per year in 1992 and 1993. Future progress of this technology is also projected.

CONVERSION OF DRILLING MUD TO A CEMENTITIOUS MATERIAL

Purpose:

To convert drilling muds into a cementitious material to eliminate cementing problems and related costs associated with (1) poor displacement (improper mud removal) during conventional cementing operations, (2) mud and cement incompatibility, (3) incomplete annular fill and seal across major washout sections within a wellbore, (4) poor casing protection across highly corrosive zones, (5) drilling mud disposal, and (6) increasingly stricter environmental regulations.

How:

Through the development of a compatible mud:cement formulation that exhibits slurry properties, displacement characteristics and set cement behavior similar to conventional Portland cement slurries.

1975 Technology:

A dependable method for converting drilling mud into a cementitious material has been sought for many years. Several compositions have been patented, but none of these are capable of being circulated in a wellbore, and provide consistent and controllable behavior. Mud and cement are incompatible, thus alternative cementitious materials to Portland cement have been investigated. Some improvements have been achieved through the addition of dispersants and certain polymers to these formulations, but a technically or commercially attractive system does not exist at this time.

1990 Technology:

Recent advancements in copolymer technology have made it possible to introduce Portland cement directly into drilling mud while maintaining control of the slurry properties and set cement behavior. Other cementitious materials such as high aluminate compounds (blast furnace slag) can also be used in these formulations. Adjustments in the formulations can provide pumping times of hours, days or even weeks allowing the mud-to-cement systems to actually be used to drill wells, then cement the casing in the wellbore in one continuous operation using rig pumps. Activators have been developed which can regulate compressive strength development to meet federal and state regulations. Research is ongoing in the U.S. and abroad as mud disposal costs and environmental regulations continue to increase.

Where:

Commercial sources of mud-to-cement formulations are available all over the world.

Technology References:

"Method and Composition for Cementing Oil Well Casing," R. E. Wyant, U.S. Patent 3,499,491, 1970.

Oil and Gas Journal, "A New Material to Cement Well Casing," F. T. Jones, October 1969.

This article introduces a mud-to-cement formulation which is capable of being used in a wellbore, however, applications are very restricted and job quality is difficult to control at this time.

"Drilling Mud Cement Composition for Well Cementing," H. K. Barthel, G. L. Miller, U.S. Patent 3,887,009.

"Drilling Mud Composition Which May Be Converted Upon Irradiation," L. H. Novak, U.S. Patent 4,547,298, 1985.

"Cementing Oil and Gas Wells Using Converted Drilling Fluid," W. N. Wilson, et al., U.S. Patent 4,883,125, 1989.

SPE 20452, "Conversion of Mud to Cement," W. N. Wilson, et al., 1990 SPE Annual Technical Conference and Exhibition.

The article summarizes the development of a new mud-to-cement technology. It also presents case histories for field applications, and illustrates the economic impact this technology could have on the industry.

DOWNHOLE FLUID FLOW MEASUREMENTS

Purpose:

Total production from a well can be obtain through surface measurements, but to fully characterize the performance of a well and to optimize its production, downhole flow measurements are required. The downhole measurements obtained from production logging sensors, provide a means of determining flow rates from individual zones and even from sets of perforations in a given zone.

How:

Downhole flow rates are determined by knowing the cross-sectional area of the flow and measuring the fluid velocity as a function of depth. This approach is relatively simple and accurate for single phase flows. However, in multiphase flows which is usually the case in downhole measurements, the changing and unknown physical properties of the flow such as density and viscosity, can cause variations in the flow response of the sensor. Accurate analysis must also address the effects of the flow regime which may vary from bubble flow to mist flow. The total flow rate determined at the various depths is then used with water holdup measurements and an estimated slip velocity to calculate the flow rate of each phase.

Currently downhole flow measurements are made using temperature surveys, noise logs, radioactive-tracer (or velocity-shot) logs, and spinner flow meters. The continuous spinner flow meters are the most widely used device today but are limited in the lower flow range. To measure the low flow rates, two types of devices based on the spinner technology are used, the full-bore flow meter and diverting flow meters. Usually in multiphase flows, a density sensor based on either gamma ray attenuation or a vertical pressure difference, provides the water holdup measurement necessary to determine the flow rate of each phase.

1990 Technology:

Continuous spinner flow meters will continue to be widely used due to their simplicity and reliability but addition sensors will be used to supplement and address the more complex conditions associated with multiphase flows. Additional improvements will be made in the fullbore and diverting flow meters for low flow rate zones. Ultrasonic technology currently used in surface measurements will be advanced and developed for downhole applications and provide the first means of measuring the velocity of an individual phase. Microprocessors and techniques using the correlation of digitized signals will improve the accuracy of ultrasonic and other types of sensors.

2000 Speculative Technology:

Advancements in ultrasonic technology will lead to ultrasonic imagining and provide velocity profiles across multiphase flows. Also in regions involving complex profiles or particle movement, laser doppler anemometry techniques may also be applied.

Results:

Improved downhole flow measurements will assist engineers in describing reservoir flow characteristics on a zone by zone basis. Monitoring these flow rates during the life of the well will provide information to improve individual well performance and aid in optimizing production from the entire reservoir.

MULTIPHASE PUMPS—PRESSURE BOOSTING FOR PRODUCTION STREAMS

Purpose:

In order to economically develop some reservoirs, particularly offshore surface and subsea reservoirs not near an established pipeline infrastructure or processing facility, there is a need for multiphase pressure boosting of the production stream. Current technology for pressure boosting production streams calls for separation of the produced fluids and then pressure boosting the gas, oil, and water with existing pumping equipment for delivery to distant processing facilities. This can be a prohibitively expensive procedure and often results in abandoning prospects that cannot be economically developed.

How:

Multiphase pump technology can be used to eliminate the separator, complicated manifolds and multiple production lines, thus significantly reducing costs.

1990 Technology:

Two types of multiphase pumps are currently being field tested, the twin-screw and the rotodynamic. Others are being developed. Each type of pump has advantages over the other.

The ***twin-screw*** pump is a positive displacement pump capable of developing high head pressures necessary for boosting over long distances. This is an old technology that has been improved to allow pumping of liquid with a significant gas fraction (95–98 percent). Size may limit the pump volume capacity.

The ***roto-dynamic pump*** is a high speed rotary pump capable of high volumes and high (> 98 percent) gas fractions. It produces a lower head, limiting its distance boosting capability. This is a relatively new technology.

It is probable that each type of pump will find application for specific reservoir conditions and location. Surface testing of both types of pumps are currently in progress and improvements in design and performance are being obtained as a result. Surface field production applications are expected by the mid-1990s.

2000 Speculative Technology:

Multiphase pump technology will be mature. Surface applications will be routinely deployed and marinization of the pumps for subsea implementation will be in progress or completed.

Results:

Development and implementation of this technology will provide the producer with an economically viable tool for development of marginal size or distant reservoirs. It will have a positive effect on exploration decisions as well, providing the potential for development of several billion barrels of deep water (3,000–8,000 feet) reserves.

THREE PHASE METERING—PRODUCTION STREAM MONITORING

Purpose:

The need for an economical means for measuring three phase (oil, water, and gas) flow rates of production streams exists. A primary use is the periodic well flow testing necessary to monitor the performance of wells and reservoirs over time in order to optimize decisions on well production rates, determine the timing of well workover times and to identify uneconomic wells. Conventionally, a "test separator," test lines and slug catcher are required. The capital cost of conventional systems can be prohibitive, particularly for offshore platform and distant subsea satellite completions and can result in abandoning prospective reservoirs.

How:

Development of a three phase flow rate meter that can accurately measure the flow of oil, water, and gas in a commingled production stream will eliminate the conventional separator, associated test lines, and equipment currently used.

1990 Technology:

Several types of three phase meters are being developed and tested. These include meters utilizing combinations of nucleonic, microwave, ultrasonic, and mechanical technologies. One meter, using microwave and mechanical methods, undergoing extensive field testing on an offshore platform is designed for subsea application. Following satisfactory performance tests, it will be deployed at a subsea satellite for further evaluation.

2000 Speculative Technology:

Three phase flow rate meters will be in wide use and will be routinely deployed in remote locations and utilized in subsea applications. It will be used on reservoirs with sufficient drive pressure to deliver the product and on reservoirs that require pressure boosting.

Results:

This technology will provide another tool for the economical development of marginal size and distant reservoirs, particularly in offshore deepwater applications. It will assist in the economical development of several billion barrels of deep water (3,000–8,000 feet) offshore reserves.

SEPARATION OF DISSOLVED ORGANICS FROM PRODUCED WATER

Purpose:

Produced water contains varying amounts and composition of organic compounds that are soluble and cannot be removed by current oil field technology which focuses on the separation of dispersed droplets of oil. Under the current regulatory regime, these dissolved organics are measured as oil and grease and reported on the Discharge Monitoring Reports to the EPA. Unfortunately, the presence of dissolved organics is not necessarily a result of any action performed by the operator; but, more often a result of the reservoir from which the oil, gas, and water are produced.

How:

The separation of dissolved organics from produced water can be accomplished by nanofiltration membrane technology. The membranes can separate the soluble molecules from the water in a manner similar to reverse osmosis filtration. The permeate stream is clean enough for discharge, injection, or softening for steam. The reject stream either becomes a new waste stream or must be recycled back upstream in the separation system.

1992 Technology:

There is currently no reliable technology available to use for the treatment of produced water to remove dissolved organics. A recent effort was made by a vendor to convince the EPA that ceramic membranes were a proven technology for this situation. Unfortunately, field testing revealed that the technology was not proven for use on produced water. Other types of membranes are also being tested, but have not successfully addressed the problems of how to handle the reject stream which may contain an enriched concentration of divalent ions and how to prevent or minimize membrane flux degradation. The reject stream may contain an enriched concentration of divalent ions which may cause scale problems where none previously existed. Membrane flux degradation occurs when the membrane becomes plugged of saturated with organic material, solids, or precipitated inorganic salts. Membrane technology is a process and not a process element as are the other treatment devices used for produced water.

2002 Speculative Technology:

Both ceramic membranes and organic based membranes will likely be available as processes.

Result:

The problems encountered in trying to apply the membrane technology process to the treatment of produced water will be suitability addressed and membrane technology will be available for the separation of dissolved organics from produced water.

NORM DISPOSAL TECHNIQUES

Purpose:

Gas production wastes which contain Naturally Occurring Radioactive Materials (NORM) must be handled and disposed of with unique care. There are state and federal regulations now being written which will define the permits for said disposal options. New and improved technologies are required to cost effectively dispose of these materials which have caused so much adverse publicity to the Industry.

How:

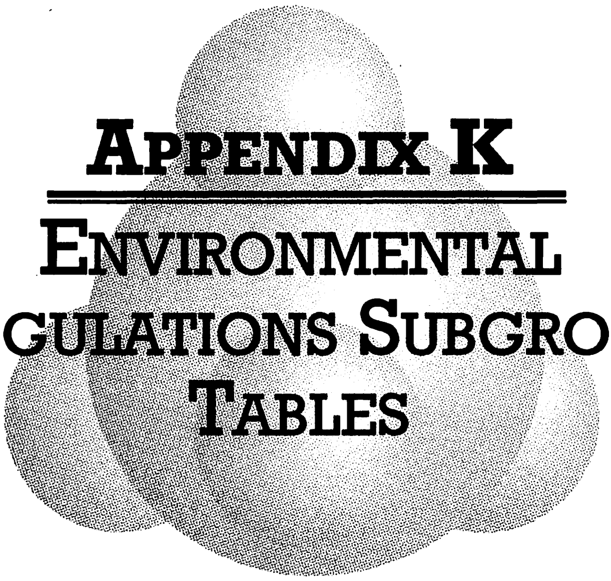
There is in reality no such thing as "radioactive disposal". The fact that a substance is radioactive cannot be changed; it will remain so until it decays away according to its preordained half-life; in the case of NORM, the half-life is some 1600 years. The only way to mitigate its effect is to remove it from the area in question (send it to the moon?), or shield all personnel from its radiation (store it in a lead box?). The best we can do is to employ some version of these two choices (as regulations permit) or not create (produce) the NORM in the first place.

1990 Technology:

The present day possibilities for NORM disposal are few and expensive. The best is probably to encase the material and equipment in a well which is to be plugged and abandoned. Other options include well injection, hydraulic fracturing, NORM waste disposal site (this is really just storage), equipment release to a smelter, landspreading (these two are really just dilution), and burial. At present none of these methods is approved by regulators carte blanch. Each instance must be negotiated and approved on a case by case basis.

2000 Technology:

The best solution to the NORM problem is not to create it. Therefore the best answer will be the development of a truly effective Barite scale control system. The solution to the already extant situation will be the evolution of an inexpensive liquid which will dissolve the NORM scales so they can easily disposed of downhole.



APPENDIX K

ENVIRONMENTAL REGULATIONS SUBGROUP TABLES

Table 1

Description of Environmental Regulatory Scenarios for the NPC Gas Study

Regulatory Scenario		
RCRA	**Balanced Scenario**	**More Stringent Scenario**
1. Management and Disposal of Drilling Wastes	Oil-based and saltwater-based muds disposed into lined pits. Fresh water-based muds discharged into unlined pits.	All water-based and oil-based muds used closed drilling systems.
2. Disposal of Associated Wastes in Central Disposal Facilities	Liquid wastes disposed into off-site disposal facility. Solid wastes disposed into non-hazardous off-site disposal facility.	Workover wastes disposed at non-hazardous sites after chemical stabilization. Other associated wastes disposed into non-hazardous off-site disposal facility.
3. a. Upgrade Emergency Pits Associated with SWD Wells and Gas Plants	All emergency pits associated with SWD wells must be lined.	All emergency pits at SWD wells and gas plants must be closed and replaced with tanks.
b. Upgrade Evaporation/Blowdown (EB) Pits	All EB pits must be closed and replaced with tanks, with scrubbers installed at 50% of the facilities; EB pits are associated with 15% of non-stripper wells.	All EB pits must be closed and replaced with tanks, with scrubbers installed at 50% of the facilities; EB pits are associated with 15% of non-stripper wells.
4. Close Existing Workover Pits	All workover pits must be closed. Assume old pits exist at 10% of well sites.	All workover pits must be closed. Assume old pits exist at 10% of well sites.

Table 1 (Continued)

Description of Environmental Regulatory Scenarios for the NPC Gas Study

	Regulatory Scenario	
RCRA	**Balanced Scenario**	**More Stringent Scenario**
5. RCRA Permit and/or Waste Testing Requirements	Assume waste characterization testing is required at SWD facilities for all E&P wastes.	Assume RCRA Part B permits are required for all existing and new storage facilities (SWD and EB). This includes pollution insurance and permit fees for produced water currently disposed under NPDES permit or by underground injection.
6. Corrective Action	No corrective action requirement.	Assume hydrocarbon and saltwater contamination at SWD facilities (2 contaminated areas/facility) and at EB facilities (1 contaminated area/facility). - 62% of sites require RFI. - 31% of sites require CMS. - 15.5% of sites require hydro-carbon contamination treatment. - 15.5% of sites require saltwater contamination treatment.
7. RCRA Permit for Onshore Disposal of Drilling Fluids from Offshore Operations	No RCRA permit requirement.	A permit fee of $2.00/ton of water-based drilling wastes from offshore facilities. Assume 69.2% of drilling fluids are water-based.

Table 1 (Continued)

Description of Environmental Regulatory Scenarios for the NPC Gas Study

Regulatory Scenario		
SDWA	**Balanced Scenario**	**More Stringent Scenario**
1. Mechanical Integrity Testing Part I	Assume pressure testing every 3.5 years, on average (based on assumption that well characteristics dictate testing every 5 years for 50% of existing wells, and every 2 years for remainder of wells); assume 10% of existing wells are packerless.	Assume positive annular pressure monitoring required weekly on wells with packers; assume all new wells have tubing and packers, assume 10% of existing wells are packerless.
Part II	Assume radioactive tracer and noise <u>or</u> temperature log every 3.5 years, on average, based on well characteristics.	Assume radioactive tracer test, noise <u>and</u> temperature log every 3.5 years, on average, based on well characteristics.
NIR Fluid Movement	No incremental requirement.	Assume OA log run to lowermost USDW.
2. Area of Review (on wells drilled prior to 1984)	No incremental requirement	Assume 1/4 mile AOR analysis on each existing injector. Assume one log applied on 75% of injectors and two logs applied on 20% of producers.
3. Corrective Action (on wells drilled prior to 1984)	No incremental requirement	Assume 10% of existing wells require remedial squeeze, 15% of abandoned wells found require reentering and replugging, and 2% of existing wells require redrilling.
4. Construction Requirements	No incremental requirement	Assume 15% of injectors require remedial squeeze, and 3% require redrilling.

Table 1 (Continued)

Description of Environmental Regulatory Scenarios for the NPC Gas Study

Regulatory Scenario		
CWA	**Balanced Scenario**	**More Stringent Scenario**
1. NSPS for Offshore Discharge of Muds and Cuttings	Assume EPA costs applied with toxicity failure rate of 1% and 1,1 mg/kg limitations for Hg&Cd in discharged fluids. This corresponds to 13.0% of drilling muds and 4% of drill cuttings being transported to shore for disposal.	Assume all drilling wastes within 4 miles are barged to shore for land disposal. Assume discharge limitations of 30,000 ppm with 15% toxicity failure rate beyond 4 miles.
2. NSPS for Offshore Discharge of Produced Water	<u>Existing facilities</u>: BPT (corresponds to a daily maximum oil and grease concentration of 72/mg/l and monthly average of 48 mg/l, i.e., no change over current requirements). <u>New facilities</u>: - Within 4 miles, treat to a maximum oil and grease concentration of 59 mg/l. - Beyond 4 miles, BPT (no change).	<u>Beyond 4 miles (all facilities)</u>: BPT (corresponds to a daily maximum oil and grease concentration of 72/mg/l and monthly average of 48 mg/l, i.e., no change over current requirements). <u>Within 4 miles (all facilities)</u>: Effluent limitations of 13 mg/l for daily maximum and 7 mg/l for maximum monthly average are required. Assume no discharge of produced water in order to achieve these limitations.
3. NPDES Stormwater Permits	50% of non-stripper wells require NPDES permit, assuming that 50% of existing wells had reportable discharge in the last 3 years.	50% of non-stripper wells require NPDES permit, assuming that 50% of existing wells had reportable discharge in the last 3 years.

Table 1 (Continued)

Description of Environmental Regulatory Scenarios for the NPC Gas Study

Regulatory Scenario		
CWA	**Balanced Scenario**	**More Stringent Scenario**
4. Above Ground Storage Tanks	Assume only leak detection and financial responsibility are required for new storage tanks larger than 1,000 barrels. No tanks larger than 1,000 barrels were assumed to be associated with gas production operations, therefore no incremental costs are incurred.	Assume all 5 aspects are required for new storage tanks larger than 500 barrels. Assumed one 1,000 barrel tank at each gas plant, and the cost for each aspect of a "spec" tank to be $1,200, with $1,000 additional cost for tanks within 1 mile of navigable water (50% of all tanks).
5. Ban on Onshore Surface Discharge of Produced Waters	Assume coastal water discharges are banned in Southern Louisiana only, accounting for 44% of produced water.	Assume coastal water discharges are banned in Southern Louisiana and half of Texas coastal areas. This corresponds to 44% of produced water in Southern Louisiana and 2.5% of produced water in Texas.
6. Wetlands Protection Requirements	Assume directional drilling for 50% of the wells in wetlands. Assume costs are 15% greater than drilling costs for conventional vertical wells.	Assume 75% of the wells in wetlands require directional drilling and 25% of the wells require wetland creation at a 2:1 mitigation ratio. Assume directional drilling costs are 15% greater than drilling costs for conventional vertical wells.

Table 1 (Continued)

Description of Environmental Regulatory Scenarios for the NPC Gas Study

Regulatory Scenario		
CAA	**Balanced Scenario**	**More Stringent Scenario**
1. Onshore Air Emission Standards	Assume air emission control equivalent to that required in California. (No incremental costs for California.) Costs include residual emission fee of $25/ton for regulated pollutants from gas plants and production facilities.	Assume air emission control technologies which are currently experimental or not in significant use. Costs include residual emission fee of $100/ton for regulated pollutants from gas plants and production facilities.
2. Offshore Air Emission Standards	Assume more stringent regulations applied to California OCS only. Assume BACT installation for all new OCS facilities, and RACT installation for all existing facilities. No emission offsets are required.	Assume more stringent regulations applied to all OCS areas. Assume BACT installation for all new OCS facilities, and RACT installation for all existing facilities. Assume residual emission offsets are required for all OCS non-attainment areas (California OCS only).

Table 2

Description of Environmental Regulatory Scenarios for the NPC Gas Study

Compliance Costs for Regulatory Scenario		
RCRA	**Balanced Scenario**	**More Stringent Scenario**

1. Management and Disposal of Drilling Wastes	Cost/well:
	= (0.94)(LC)(FUP)(0.38) + (0.06)(LC)(FUP) + (3.00)(DWF)(WD)(0.70)
	where:
	LC = liner installation cost
	FUP= fraction of pits which are unlined
	WD = well depth (feet)
	DWF= drilling waste volume/foot drilled
	For U.S. Average Gas Wells:
	Cost = $16,492/well
		Cost/well:
		= (8.10/ft)(average well depth)
		For U.S. Average Gas Wells (7,217 ft):
		Cost = $58,458/well

2. Disposal of Associated Wastes in Central Disposal Facilities	Cost/well/year: All regions except Appalachia = (12.50/Bbl)(Bbl solid waste/well/yr) + 4.00/Bbl)(Bbl liquid waste/well/yr) Appalachia = (12.50/Bbl)(Bbl solid waste/well/yr) + (1.00/Bbl)(Bbl liquid waste/well/yr) **For U.S. Average Gas Wells:** Cost = $13/well/yr	Cost/well/year: = (12.00)(Bbl associated waste/well/yr) +(65.00)(Bbl workover waste/well/yr) **For U.S. Average Gas Wells:** Cost = $48/well/yr

Table 2 (Continued)

Description of Environmental Regulatory Scenarios for the NPC Gas Study

Compliance Costs for Regulatory Scenario		
RCRA	**Balanced Scenario**	**More Stringent Scenario**
3. a. Upgrade Emergency Pits Associated with SWD Wells and Gas Plants	Cost/well: All regions except Appalachia (1 tank @1000 Bbl) = (1,235/2/z) Appalachia = (350/2/z) where z = number of wells per SWD well **For U.S. Average Gas Wells:** Cost = $2.00/well	Cost/well: All regions except Appalachia (2 tanks @500 Bbl and 1 tank @1000 Bbl) Existing wells: =(60,000/x)+(75,000/2/z) New wells: =(35,000/x)+(50,000/2/z) Appalachia (2 tanks @250 Bbl and 1 tank @1000 Bbl) Existing wells: =(60,000/x)+(50,000/2/z) New wells: =(35,000/x)+(40,000/2/z) where x= number of wells per gas plant z= number of wells per SWD well **For U.S. Average Gas Wells:** Cost = $256/existing well = $160/new well

Table 2 (Continued)

Description of Environmental Regulatory Scenarios for the NPC Gas Study

Compliance Costs for Regulatory Scenario		
RCRA	**Balanced Scenario**	**More Stringent Scenario**
3. b. Upgrade Evaporation/Blowdown (EB) pits	All regions except Appalachia (1 tank @500 Bbl) Existing wells: =($55,000*0.15) New non-stripper wells: =($30,000*0.15) Appalachia (1 tank @50 Bbl) Existing wells: =(8,000*0.15) New non-stripper wells: =(3,000*0.15) **For U.S. Average Gas Wells:** Cost = $8,250/existing well = $4,500/new well	All regions except Appalachia (1 tank @500 Bbl) Existing wells: =($55,000*0.15) New non-stripper wells: =($30,000*0.15) Appalachia (1 tank @50 Bbl) Existing wells: =(8,000*0.15) New non-stripper wells: =(3,000*0.15) **For U.S. Average Gas Wells:** Cost = $8,250/existing non-stripper well = $4,500/new non-stripper well

Table 2 (Continued)

Description of Environmental Regulatory Scenarios for the NPC Gas Study

Compliance Costs for Regulatory Scenario		
RCRA	**Balanced Scenario**	**More Stringent Scenario**
4. Close Existing Workover Pits	Cost/well: All regions except Appalachia Existing wells: = $2,500 New wells: = 0 Appalachia (1 tank @50 Bbl) Existing wells: = $500 New wells: = 0	Cost/well: All regions except Appalachia Existing wells: = $2,500 New wells: = 0 Appalachia (1 tank @50 Bbl) Existing wells: = $500 New wells: = 0

Table 2 (Continued)

Description of Environmental Regulatory Scenarios for the NPC Gas Study

Compliance Costs for Regulatory Scenario		
RCRA	**Balanced Scenario**	**More Stringent Scenario**
5. RCRA Permit and/or Waste Testing Requirements	Cost/well Existing wells: = ($4,890/2/z) New wells: = ($1,725 + $4,890/2/z) where z = number wells per SWD well **For U.S. Average Gas Wells:** Cost = $8/existing well = $1,733/new well	Cost/well at SWD: = ($16,100/2/z) at EB: = $1,665 Cost/well/year at SWD: = ($0.40*y)+($8,840/2/z) at EB: = $1,177 where z= number wells per SWD well y= produced water (bbl/well/yr) EB pits exist at 15% of all existing and new, non-stripper gas wells **For U.S. Average Gas Wells:** Costs = $1,691/well + $1,803/well/yr

Table 2 (Continued)

Description of Environmental Regulatory Scenarios for the NPC Gas Study

Compliance Costs for Regulatory Scenario		
RCRA	**Balanced Scenario**	**More Stringent Scenario**
6. Corrective Action	No incremental costs	Only at existing wells Cost/well at SWD = 340,426/z at EB = $20,184 Cost/well/year at SWD: = ($3,294/z) at EB: = $340 where z = number wells per SWD well and EB exist at 15% of wells **For U.S. Average Gas Wells:** Costs = $21,293/well + $351/well/yr
7. RCRA Permit for Onshore Disposal of Drilling Fluids from Offshore Operations	No incremental costs	Cost/well Drilling muds: = ($0.40/Bbl)(Bbl muds/well)(0.692) Drill cuttings: = ($0.65/Bbl)(Bbl cuttings/well)(0.692) **For Average Wells in the Gulf of Mexico:** Within 4 miles from shore Costs = $7,666/well Beyond 4 miles Costs = $3,796/well

Table 2 (Continued)

Description of Environmental Regulatory Scenarios for the NPC Gas Study

Compliance Costs for Regulatory Scenario		
SDWA	**Balanced Scenario**	**More Stringent Scenario**
1. Mechanical Integrity Testing		
Part I	Cost/well/year Existing wells: = (0.9)(400/3.5-80)/z New wells: = (400/3.5-80)/z	Cost/well Existing wells: = (0.9)($1,500)/z New wells: = $1,500/z Cost/well/year Existing wells: = (0.9)($23.75)(52)/z New wells: = ($23.75)(52)/z
Part II	Cost/well/year = (2,014 + 0.43/ft)/3.5/z	Cost/well/year = (2,464 + 0.53/ft)/3.5/z
NIR Fluid Movement	No incremental costs where z = number of wells per SWD well **For an average well,injection zone 2000 ft:** Total Cost = $2.77/existing well/yr = $2.78/new well/yr	Cost/well/year = (771 + 0.17/ft)/z where z = number of wells per SWD well **For an average well, injection zone 2,000 ft:** Total Cost = $4.39/existing well + $10.52/existing well/yr = $4.89/new well + $10.92/new well/yr

Table 2 (Continued)

Description of Environmental Regulatory Scenarios for the NPC Gas Study

Compliance Costs for Regulatory Scenario		
SDWA	**Balanced Scenario**	**More Stringent Scenario**

2. Area of Review (on wells drilled prior to 1984)	No incremental costs	Cost/existing injector
		=(0.86){(23340)+[(0.75)+ (PW)(0.2)(2)](3046+.605/ft)}
		where
		PW = number of producers/injector
		For an average 5,000 ft injection well:
		Cost = $29,084/existing injector

3. Corrective Action (on wells drilled prior to 1984)	No incremental costs	Cost/existing injector =(PW) {(0.1)(18000+0.53/ft)+ (0.02)(cost to redrill)}+ (0.15)(AW) {(0.9)(30250+2.35/ft)+ (0.10)(60500+1.4/ft)} where PW = number of producers/injector AW = number of abandon well/injector **For an average 5,000 ft injection well:** Cost/injector well = $48,074+(4.9%* cost to redrill)
4. Construction Requirement	No incremental costs	Cost/existing injector = (0.86){(0.15)(18000+0.53/ft) + (0.03)[(17000+1.15/ft) + (cost to redrill well)]} **For an average 5,000 ft injection well:** Cost/injector well = $3,250+(2.6%* cost to redrill)

Table 2 (Continued)

Description of Environmental Regulatory Scenarios for the NPC Gas Study

Compliance Costs for Regulatory Scenario		
CWA	**Balanced Scenario**	**More Stringent Scenario**
1. NSPS for Offshore Discharge of Muds and Cuttings	Cost/well = [(0.13)($46.61/ft)+(0.04)($6.11/ft)] (0.692)(10000 ft/well) **For U.S. Average Gas Wells:** Cost = $43,622/well	Cost/well = (Wc) (Wd) (0.692) where Wc = API compliance costs/foot Wd = Average well depth **For Average Wells in the Gulf of Mexico:** Within 4 miles from shore Costs = $393,794/well Beyond 4 miles Costs = $187,771/well
2. NSPS for Offshore Discharge of Produced Water	Cost/well Existing well: no costs New well: NSPS costs	Cost/well Beyond 4 miles : no costs Within 4 miles : re-injection costs
3. NPDES Stormwater Permits	Cost/non-stripper well (non-Appalachia): = (0.50)($4,500) = $2,250/non-stripper well Cost/non-stripper well (Appalachia): = (0.10)($4,500) = $450/non-stripper well	Cost/non-stripper well (non-Appalachia): = (0.50)($4,500) = $2,250/non-stripper well Cost/non-stripper well (Appalachia): = (0.10)($4,500) = $450/non-stripper well

Table 2 (Continued)

Description of Environmental Regulatory Scenarios for the NPC Gas Study

Compliance Costs for Regulatory Scenarios		
CWA	**Balanced Scenario**	**More Stringent Scenario**
4. Above Ground Storage Tanks	No incremental cost for gas operations	Cost/well = (1/x)[(5)(1,200)+(0.5)(1,000)] where x = number of wells per gas plant **For U.S. Average Gas Wells:** Cost = $14/well
5. Ban on Onshore Surface Discharge of Produced Waters	Cost/injector well = (FSD)(0.50) [(DC)+(CC)] Cost/injector/yr = (FSD)(30,000) where FSD = ratio of new injector/existing injector DC = drilling cost CC = cost to convert a producer to an injector **For an average well in Louisiana:** Cost = $16,527/well	Cost/injector = (FSD)(0.50) [(DC)+(CC)] Cost/injector/yr = (FSD)(30,000) where FSD = ratio of new injector/existing injector DC = drilling cost CC = cost to convert a producer to an injector **For an average well in Louisiana:** Cost = $16,527/well
6. Wetlands Protection Requirements	Cost/well = (0.5)(0.15)(x)(DC) where DC = drilling cost x = fraction of wetlands	Cost/well = (0.75)(0.15)(x)(DC)+ + (0.25)(x)(mitigation costs) where DC = drilling cost x = fraction of wetlands mitigation costs = $8,000 per well

Table 2 (Continued)

Description of Environmental Regulatory Scenarios for the NPC Gas Study

Compliance Costs for Regulatory Scenario		
CAA	**Balanced Scenario**	**More Stringent Scenario**
1. Onshore Air Emission Standards	Cost/well: All regions except Appalachia and California = (2,813 + 42,500/x) Appalachian region = (188 + 42,500/x) California = 0 Cost/well/year: All regions except Appalachia = (1,338 + 62,500/x) Appalachian region = (89 + 62,500/x) California = 0 where x = number of wells per gas plant **For U.S. Average Gas Wells:** Capital Costs = $2,908/well Operating Costs = $1,478/well/yr	Cost/well: All regions except Appalachia = (18,313 + 2,292,500/x) Appalachian region = (1,221 + 2,292,500/x) Cost/well/year: All regions except Appalachia = (1,338 + 62,500/x) Appalachian region = (89 + 62,500/x) where x = number of wells per gas plant **For U.S. Average Gas Wells:** Capital Costs = $23,442/well Operating Costs = $1,478/well/yr
2. Offshore Air Emission Standards	Cost without offsets are applied to California only. See Table 2A for cost details.	Costs without offsets are applied to all OCS areas. Costs with offsets are applied to California OCS areas only. See Table 2A for cost details.

Table 2A

Description of Offshore Air Emission Standards for the Environmental Scenarios for the NPC Gas Study

Air Emission Costs with No Offset Requirements		
Exploration Phase:	$177,400	per exploratory well
Platform Construction Phase:		
Capital Costs	$383,600	per platform
Operating Costs	$238,900	per platform per year (during construction)
Development Drilling Phase:		
Capital Costs	$398,000	per platform
Operating Costs	$511,700	per platform per year
Production Phase:		
Operating Costs	$511,700	per platform per year
Air Emission Costs with Offset Requirements		
Exploration Phase:	$783,400	per exploratory well
Platform Construction Phase:		
Capital Costs	$383,600	per platform
Operating Costs	$7,690,900	per platform per year (during construction)
Development Drilling Phase:		
Capital Costs	$398,000	per platform
Operating Costs	$2,287,700	per platform per year
Production Phase:		
Operating Costs	$1,927,700	per platform per year

Table 3

Summary of Representative Incremental Initial Compliance Costs for U.S. Average Onshore Gas Wells - Reference Case Scenario

Regulatory Initiative	Estimated Initial Compliance Cost	
RCRA	Cost/Existing Well	Cost/New Well
1. Management and Disposal of Drilling Wastes	----	$16,492
2. Disposal of Associated Wastes in Central Disposal Facilities	----	----
3. a. Upgrade Emergency Pits Associated with SWD Wells and Gas Plants b. Upgrade Evaporation/Blowdown (EB) pits	$2 $8,250	$2 $4,500
4. Replace Workover Pits with Portable Tanks	$2,500	----
5. RCRA Permit and/or Waste Testing Requirements	$8	$1,733
6. Corrective Action	----	----
SDWA	Cost/Existing Well	Cost/New Well
1. Mechanical Integrity Testing	----	----
2. Area of Review	----	----
3. Corrective Action	----	----
4. Construction Requirement	----	----
CWA	Cost/Existing Well	Cost/New Well
1. NPDES Stormwater Permits	$2,250	$2,250
2. Above Ground Storage Tank	----	----
3. Onshore Discharge Ban	$3,725	$3,725
4. Wetlands Protection	----	$2,873
CAA	Cost/Existing Well	Cost/New Well
1. Onshore Air Emission Standards	$2,908	$2,908
Total	**$19,643**	**$34,483**

Notes:
1) Incremental cost for a U.S. average gas well drilled to 7,217 feet.
2) Costs allocated to producer based on U.S. average number of 307 producers per SWD well and 447 producers per gas plant.
3) Area-specific costs (such as those corresponding to wetlands or the onshore discharge ban) are incorporated based on the weighted-average contribution for the area.

Table 4

Summary of Representative Incremental Annual Operating Compliance Costs for U.S. Average Onshore Gas Wells - Reference Case Scenario

Regulatory Initiative	Estimated Annual Operating Cost	
RCRA	Cost/Existing Well	Cost/New Well
1. Management and Disposal of Drilling Wastes	----	----
2. Disposal of Associated Wastes in Central Disposal Facilities	$13	$13
3. a. Upgrade Emergency Pits Associated with SWD Wells and Gas Plants	----	----
b. Upgrade Evaporation/Blowdown (EB) pits	----	----
4. Replace Workover Pits with Portable Tanks	----	----
5. RCRA Permit and/or Waste Testing Requirements	----	----
6. Corrective Action	----	----
SDWA	Cost/Existing Well	Cost/New Well
1. Mechanical Integrity Testing	$3	$3
2. Area of Review	----	----
3. Corrective Action	----	----
4. Construction Requirement	----	----
CWA	Cost/Existing Well	Cost/New Well
1. NPDES Stormwater Permits	----	----
2. Above Ground Storage Tank	----	----
3. Onshore Discharge Ban	$485	$485
4. Wetlands Protection	----	----
CAA	Cost/Existing Well	Cost/New Well
1. Onshore Air Emission Standards	$1,478	$1,478
Total	**$1,979**	**$1,979**

Notes: 1) Incremental cost for a U.S. average gas well drilled to 7,217 feet.
2) Costs allocated to producer based on U.S. average number of 307 producers per SWD well and 447 producers per gas plant.
3) Area-specific costs (such as those corresponding to wetlands or the onshore discharge ban) are incorporated based on the weighted-average contribution for the area.

Table 5

Summary of Representative Incremental Initial Compliance Costs for U.S. Average Onshore Gas Wells - More Stringent Scenario

Regulatory Initiative	Estimated Initial Compliance Cost	
RCRA	Cost/Existing Well	Cost/New Well
1. Management and Disposal of Drilling Wastes	----	$58,458
2. Disposal of Associated Wastes in Central Disposal Facilities	----	----
3. a. Upgrade Emergency Pits Associated with SWD Wells and Gas Plants	$256	$160
b. Upgrade Evaporation/Blowdown (EB) pits	$8,250	$4,500
4. Replace Workover Pits with Portable Tanks	$2,500	----
5. RCRA Permit and/or Waste Testing Requirements	$1,691	$1,691
6. Corrective Action	$21,293	----
SDWA	Cost/Existing Well	Cost/New Well
1. Mechanical Integrity Testing	$4	$5
2. Area of Review	$95	----
3. Corrective Action	$181	----
4. Construction Requirement	$23	----
CWA	Cost/Existing Well	Cost/New Well
1. NPDES Stormwater Permits	$2,250	$2,250
2. Above Ground Storage Tank	$14	$14
3. Onshore Discharge Ban	$3,824	$3,824
4. Wetlands Protection	----	$4,503
CAA	Cost/Existing Well	Cost/New Well
1. Onshore Air Emission Standards	$23,422	$23,422
Total	**$63,803**	**$98,827**

Notes:
1) Incremental cost for a U.S. average gas well drilled to 7,217 feet.
2) Costs allocated to producer based on U.S. average number of 307 producers per SWD well and 447 producers per gas plant.
3) Costs for average 5,000 foot injection wells are assumed for SDWA2, SDWA3 and SDWA4. Cost to redrill a 5,000-foot well in region G is assumed to be $150,000.
4) Area-specific costs (such as those corresponding to wetlands or the onshore discharge ban) are incorporated based on the weighted-average contribution for the area.

Table 6

Summary of Representative Incremental Annual Operating Compliance Costs for U.S. Average Onshore Gas Wells - More Stringent Scenario

Regulatory Initiative	Estimated Annual Operating Cost	
RCRA	Cost/Existing Well	Cost/New Well
1. Management and Disposal of Drilling Wastes	----	----
2. Disposal of Associated Wastes in Central Disposal Facilities	$48	$48
3. a. Upgrade Emergency Pits Associated with SWD Wells and Gas Plants	----	----
b. Upgrade Evaporation/Blowdown (EB) pits	----	----
4. Replace Workover Pits with Portable Tanks	----	----
5. RCRA Permit and/or Waste Testing Requirements	$1,803	$1,803
6. Corrective Action	$351	----
SDWA	Cost/Existing Well	Cost/New Well
1. Mechanical Integrity Testing	$11	$11
2. Area of Review (injector only)	----	----
3. Corrective Action (injector only)	----	----
4. Construction Requirement (injector only)	----	----
CWA	Cost/Existing Well	Cost/New Well
1. NPDES Stormwater Permits	----	----
2. Above Ground Storage Tank	----	----
3. Onshore Discharge Ban	$497	$497
4. Wetlands Protection	----	----
CAA	Cost/Existing Well	Cost/New Well
1. Onshore Air Emission Standards	$1,478	$1,478
Total	**$4,188**	**$3,837**

Notes:
1) Incremental cost for a U.S. average gas well drilled to 7,217 feet.
2) Costs allocated to producer based on U.S. average number of 307 producers per SWD well and 447 producers per gas plant.
3) Costs for average 5,000 foot injection wells are assumed for SDWA2, SDWA3 and SDWA4. Cost to redrill a 5,000-foot well in region G is assumed to be $150,000.
4) Area-specific costs (such as those corresponding to wetlands or the onshore discharge ban) are incorporated based on the weighted-average contribution for the area.

Table 7

Summary of Representative Incremental Initial Compliance Costs for Average Offshore Wells in the Gulf of Mexico - Reference Case Scenario

Regulatory Initiative	**Estimated Initial Compliance Cost**	
	Cost/Existing Well	Cost/New Well
RCRA Permit Fees for Onshore Disposal	----	----
Discharge of Muds & Cuttings	----	$43,622
Discharge of Produced Water	----	$0 - $46,766
Offshore Air Emission Standards	----	----
Total	----	$43,622 - $90,388

Notes: 1) Range in costs represents those associated with operations within and beyond the four-mile demarcation in EPA's proposed offshore discharge requirements.
2) Maximum gas production rate = 40 MMcf/d/platform.
3) For Gulf of Mexico, an 18-slot platform is assumed to be a "typical" platform.

Table 8

Summary of Representative Incremental Annual Operating Compliance Costs for Average Offshore Wells in the Gulf of Mexico - Reference Case Scenario

Regulatory Initiative	Estimated Annual Operating Costs	
	Cost/Existing Well	Cost/New Well
RCRA Permit Fees for Onshore Disposal	----	----
Discharge of Muds & Cuttings	----	----
Discharge of Produced Water	----	$0 - $8,144
Offshore Air Emission Standards	----	----
Total	----	$0 - $8,144

Notes: 1) Range in costs represents those associated with operations within and beyond the four-mile demarcation in EPA's proposed offshore discharge requirements.
2) Maximum gas production rate = 40 MMcf/d/platform.
3) For Gulf of Mexico, an 18-slot platform is assumed to be a "typical" platform.

Table 9

Summary of Representative Incremental Initial Compliance Costs for Average Offshore Wells in the Gulf of Mexico - More Stringent Scenario

Regulatory Initiative	Estimated Initial Compliance Cost	
	Cost/Existing Well	Cost/New Well
RCRA Permit Fees for Onshore Disposal	----	$3,796 - $7,666
Discharge of Muds & Cuttings	----	$181,771 - $393,794
Discharge of Produced Water	$0 - $58,766	$0 - $61,905
Offshore Air Emission Standards	----	$699,594
Total	$0 - $58,766	$885,161 - $1,162,959

Notes: 1) Range in costs represents those associated with operations within and beyond the four-mile demarcation in EPA's proposed offshore discharge requirements.
2) Maximum gas production rate = 40 MMcf/d/platform.
3) For Gulf of Mexico, an 18-slot platform is assumed to be a "typical" platform.

Table 10

Summary of Representative Incremental Annual Operating Compliance Costs for Average Offshore Wells in the Gulf of Mexico - More Stringent Scenario

Regulatory Initiative	Estimated Annual Operating Costs	
	Cost/Existing Well	Cost/New Well
RCRA Permit Fees for Onshore Disposal	----	----
Discharge of Muds & Cuttings	----	----
Discharge of Produced Water	$0 - $3,109	$0 - $3,313
Offshore Air Emission Standards	----	$31,981
Total	$0 - $3,109	$28,428 - $35,294

Notes: 1) Range in costs represents those associated with operations within and beyond the four-mile demarcation in EPA's proposed offshore discharge requirements.
2) Maximum gas production rate = 40 MMcf/d/platform.
3) For Gulf of Mexico, an 18-slot platform is assumed to be a "typical" platform.

Table 11

Suggested Timing of Resource Availability by OCS Area

	Date for Leasing	Lag before Exploration
Central Gulf of Mexico	1990	3 years
Western Gulf of Mexico	1990	3 years
Eastern Gulf of Mexico, S. of 26° N. latitude	2010	5 years
Eastern Gulf of Mexico, N. of 26° N. latitude	1994	3 years
North Atlantic	2005	5 years
Mid-Atlantic	1997	5 years
South Atlantic	1998	5 years
Florida Straits	2010	5 years
Southern California	2000	5 years
Central California	2000	5 years
Northern California	2000	5 years
Washington/Oregon	2005	5 years
Beaufort Sea	1993	5 years
Chukchi Sea	1994	5 years
Cook Inlet	1994	5 years
North Aleutian Basin	2000	6 years
Other western Alaska planning areas	1996	6 years
Other southern Alaska planning areas	2010	6 years

Reference Case 1
Table 12

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22-Jun-92

$3.50 CASE

TOTAL PRODUCTION	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	TOTAL 92-2010	DELTA	DELTA %
REGION A																							
Bal	624	627	638	638	617	597	614	633	665	707	752	776	786	805	831	851	855	855	846	853	13946	2119	15.19%
High	624	627	637	603	545	484	507	525	555	588	628	646	642	650	677	700	707	708	704	694	11827		
REGION B																							
Bal	288	350	402	447	464	474	483	483	475	470	472	481	483	512	530	548	562	573	588	594	9401	335	3.58%
High	288	350	402	450	482	471	478	473	471	467	468	474	482	495	508	510	515	527	537	532	9066		
REGION C																							
Bal	183	199	215	224	219	222	224	228	244	268	294	317	340	355	347	341	347	360	379	409	5532	1371	24.78%
High	183	199	214	223	215	202	190	176	169	174	178	180	184	194	209	231	262	292	324	343	4161		
REGION D																							
Bal	1307	1318	1328	1289	1221	1160	1149	1159	1150	1148	1154	1160	1148	1133	1138	1154	1152	1173	1224	1322	22688	1913	8.43%
High	1307	1318	1328	1292	1191	1136	1124	1093	1048	1006	1009	1005	995	1004	1012	1038	1035	1038	1034	1075	20775		
REGION E																							
Bal	1071	1068	1053	1041	1018	999	897	890	963	914	868	807	748	719	710	715	714	723	718	680	16439	534	3.25%
High	1071	1068	1053	1042	893	974	973	958	941	890	848	819	762	749	725	671	623	604	600	582	15805		
REGION G																							
Bal	2120	2052	2002	1936	1835	1742	1662	1627	1812	1637	1698	1768	1855	1830	2011	2076	2102	2089	2000	1944	35574	1629	4.58%
High	2120	2052	2012	1952	1628	1718	1629	1562	1565	1576	1628	1698	1768	1658	1653	1865	1679	1873	1818	1771	33945		
REGION WL																							
Bal	98	105	107	101	95	95	98	98	99	100	102	104	105	107	111	118	118	118	117	118	2008	92	4.58%
High	98	105	107	101	94	95	95	94	98	99	100	100	100	102	105	107	107	105	102	100	1918		
REGION FR																							
Bal	795	961	846	804	758	768	782	769	784	794	825	840	865	898	943	999	1058	1165	1299	1507	17531	1765	10.07%
High	795	861	848	801	749	778	782	772	777	751	744	754	758	774	799	840	899	962	1033	1110	15768		
REGION SJ																							
Bal	490	697	712	817	880	1068	1137	1208	1278	1347	1418	1472	1473	1474	1475	1478	1480	1458	1438	1382	23682	782	3.34%
High	490	697	713	818	881	1068	1137	1208	1278	1347	1378	1378	1367	1371	1367	1385	1392	1388	1374	1349	22890		
REGION OV																							
Bal	175	210	218	222	228	248	280	304	333	352	368	389	418	431	464	498	514	532	548	574	7119	-127	-1.79%
High	175	210	218	223	228	255	288	311	337	349	368	391	418	445	475	505	534	554	565	573	7246		
REGION JN																							
Bal	3204	3312	3440	3253	3238	3264	3162	3074	2994	2918	2867	2858	2839	2831	2803	2738	2589	2434	2289	2150	55047	1574	2.86%
High	3204	3312	3439	3248	3238	3224	3115	3024	2960	2898	2863	2827	2805	2768	2660	2557	2379	2212	2053	1871	53473		
REGION JS																							
Bal	1398	1399	1407	1337	1320	1335	1351	1365	1360	1397	1438	1464	1498	1530	1562	1587	1584	1577	1528	1495	27552	462	1.68%
High	1398	1399	1404	1339	1320	1321	1321	1332	1360	1391	1419	1439	1454	1488	1527	1529	1524	1535	1519	1469	27090		
REGION L																							
Bal	302	308	318	319	332	350	378	408	447	484	527	578	641	715	782	861	908	954	991	1007	11314	-109	-0.96%
High	302	308	318	318	330	349	377	408	451	491	533	585	648	723	798	884	922	974	1015	1015	11423		
REGION BO																							
Bal	78	149	245	416	486	554	624	693	708	705	693	677	658	637	621	594	573	551	528	507	10814	44	0.41%
High	78	149	245	416	486	554	624	693	703	701	690	674	653	634	618	591	588	548	524	500	10570		
REGION EGO																							
Bal	4817	4578	4433	4311	4161	4017	3906	3913	3958	4045	4115	4236	4338	4423	4510	4589	4651	4591	4470	4318	81559	4581	5.62%
High	4817	4578	4431	4334	4108	3925	3813	3751	3733	3769	3854	3928	3973	4000	4060	4173	4229	4208	4121	3992	76978		
REGION LO																							
Bal	49	53	57	60	62	66	71	80	98	93	91	88	87	86	85	83	81	80	79	75	1473	3	0.20%
High	49	53	57	59	62	66	71	80	98	93	91	89	87	86	84	82	81	79	79	75	1470		
REGIONAO																							
Bal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	135	173	173	231	712	356	50.00%
High	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	167	169	356		

NOTE: These printouts are not based on the final Reference Case runs found in Volume VI and other parts of this report. The differences were judged not to be significant and therefore the cases were not rerun.

Reference Case 2
Table 13

D:\WK1\NPCENVS\WJFNPC25.WK1
22-Jun-92

$2.50 CASE

TOTAL PRODUCTION	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	TOTAL 92-2010	DELTA	DELTA %
REGION A																										
Bal	639	646	642	624	627	638	636	616	595	610	627	656	691	724	743	752	770	791	807	811	800	777	788	13437	2271	16.90%
High	639	646	642	624	627	837	601	539	473	497	516	543	574	606	623	616	614	627	632	625	816	604	596	11188		
REGION B																										
Bal	229	233	255	286	350	402	448	464	472	477	472	459	444	440	445	452	464	478	489	502	519	523	517	8817	305	3.46%
High	229	233	255	286	350	402	451	462	468	470	481	447	433	429	436	443	454	464	468	474	472	468	462	8512		
REGIONC																										
Bal	124	146	164	183	199	215	224	219	209	200	200	200	204	212	233	260	289	310	326	325	297	284	283	4689	1852	39.50%
High	124	146	164	183	199	209	216	206	193	181	187	156	150	144	136	127	116	108	100	101	104	109	115	2837		
REGION D																										
Bal	1288	1321	1312	1307	1316	1328	1299	1220	1156	1147	1129	1091	1032	1016	993	981	957	987	1040	1054	1069	1091	1153	21041	2502	11.89%
High	1288	1321	1312	1307	1316	1326	1294	1186	1131	1118	1086	1038	978	922	868	837	818	799	792	768	753	742	771	18539		
REGION E																										
Bal	1171	1131	1100	1071	1068	1053	1042	1015	999	998	990	981	903	846	776	695	634	579	523	481	462	448	433	14906	270	1.81%
High	1171	1131	1100	1071	1068	1053	1044	993	974	973	957	922	872	802	723	636	568	525	485	471	493	524	553	14636		
REGION G																										
Bal	2188	2140	2206	2120	2052	2001	1934	1831	1737	1656	1619	1603	1604	1651	1683	1743	1767	1759	1760	1735	1675	1589	1557	32978	1891	5.73%
High	2188	2140	2206	2120	2052	2011	1953	1624	1713	1807	1558	1543	1549	1592	1614	1648	1624	1598	1563	1506	1445	1353	1332	31065		
REGION WL																										
Bal	94	93	96	96	105	107	101	96	96	96	96	97	96	102	104	105	107	109	111	114	114	112	108	1978	118	5.97%
High	94	93	96	96	105	107	101	95	95	95	94	96	96	99	99	100	99	99	100	99	97	93	89	1880		
REGION FR																										
Bal	701	724	775	795	861	846	803	756	775	768	767	784	784	772	781	798	815	830	845	883	932	1004	1083	15887	1327	6.35%
High	701	724	775	795	861	846	803	750	781	787	789	787	740	712	697	682	710	733	754	763	788	810	827	14560		
REGION SJ																										
Bal	412	407	468	490	697	712	815	879	1068	1137	1208	1206	1207	1251	1314	1421	1404	1390	1389	1370	1353	1323	1260	22432	725	3.23%
High	412	407	468	490	897	713	618	680	1068	1137	1208	1277	1348	1349	1325	1300	1289	1270	1271	1254	1208	1171	1128	21707		
REGIONOV																										
Bal	141	174	173	175	210	216	222	228	249	282	304	339	351	368	384	405	430	457	468	514	534	544	549	7072	-53	-0.75%
High	141	174	173	175	210	216	223	229	257	291	311	337	348	364	388	414	441	471	497	520	534	537	537	7125		
REGIONJN																										
Bal	3020	3132	3283	3204	3312	3441	3256	3236	3262	3135	3004	2821	2832	2774	2736	2704	2655	2563	2409	2190	2005	1872	1792	52099	1434	2.75%
High	3020	3132	3283	3204	3312	3442	3247	3237	3212	3100	2989	2909	2840	2778	2709	2617	2517	2388	2231	2042	1856	1692	1571	50665		
REGIONJS																										
Bal	1415	1433	1425	1398	1399	1407	1337	1320	1339	1347	1362	1362	1369	1392	1439	1468	1525	1528	1514	1481	1420	1388	1305	26682	803	3.01%
High	1415	1433	1425	1388	1399	1405	1338	1321	1321	1319	1330	1359	1388	1405	1428	1426	1423	1426	1399	1348	1318	1291	1237	25879		
REGION L																										
Bal	326	300	308	302	308	318	319	332	351	379	407	453	492	536	589	653	727	803	872	930	970	1000	996	11433	68	0.59%
High	326	300	308	302	308	316	318	330	349	377	406	451	491	534	585	647	727	802	868	925	972	989	970	11365		
REGION BO																										
Bal	7	14	39	78	149	245	416	485	554	624	693	706	693	684	670	652	630	611	580	554	530	502	478	10456	45	0.43%
High	7	14	39	78	149	245	418	485	554	624	693	703	688	680	688	648	627	608	577	551	527	488	472	10411		
REGION EGO																										
Bal	4909	4946	5123	4817	4578	4433	4313	4159	4008	3869	3867	3887	3886	3911	3869	3868	3867	3856	3896	3676	3776	3638	3488	75045	5188	6.91%
High	4909	4846	5123	4817	4576	4432	4338	4107	3934	3811	3736	3650	3597	3529	3478	3547	3575	3534	3422	3299	3161	3102	3031	69859		
REGION LO																										
Bal	47	45	48	49	53	57	60	62	66	71	80	98	95	92	90	89	88	85	64	83	62	81	78	1494	25	1.67%
High	47	45	48	49	53	57	59	62	66	71	80	98	93	91	88	87	88	84	62	81	80	79	74	1498		
REGIONAO																										
Bal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	154	174	187	515	515	100.00%
High	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		

15-Jun

Reference Case 1
Table 14

NATIONAL PETROLEUM COUNCIL ENVIRONMENTAL REGULATION LOW IMPACT SCENARIO
EXISTING WELLS
$3.50 STANDALONE RUN (HIGH REFERENCE)

		$1.67/MMBTU 1989$ WELLHEAD GAS PRICE (1996) MAXIMUM GAS PRICE $3.50/MMBTU BY YEAR 2014 LIFE OF WELL PAYOUT (7% ROR)									$1.67/MMBTU 1989$ WELLHEAD GAS PRICE (1996) MAXIMUM GAS PRICE $3.50/MMBTU BY YEAR 2014 LIFE OF WELL PAYOUT (7% ROR)	
				FIRST YEAR IMPACT:							TOTAL IMPACT FIRST TWENTY YEARS:	
HYDROCARBON MODEL REGIONS, (ONSHORE) :		STARTING WELL TOTALS	BASE WELLS UNECON	ADDITIONAL WELLS ABND	ADDITIONAL WELLS %	BASE PROD (BCF)	DELTA PROD. (BCF)	DELTA PROD. %	DELTA RESERVES (BCF)	ADDED COST ($MM)	DELTA RESERVES (BCF)	ADDED COST* ($MM)
A -	APPALACHIA	117330	0	44,585	NA	569	(58)	-10%	(394)	346	(631)	1,261
B -	EAST GULF ONSHORE (MAFLA)	2319	152	176	116%	210	(1)	-0%	(2)	32	(3)	74
C -	NORTH CENTRAL (MIDWEST)	2856	432	306	71%	96	(1)	-1%	(3)	34	(5)	78
D -	ARKLA-TEXAS	25836	4,147	4,569	110%	1,146	(17)	-1%	(42)	270	(57)	563
E -	SOUTH LOUISIANA ONSHORE	2473	79	124	157%	1,000	(1)	-0%	(4)	164	(10)	350
G -	TEXAS GULF ONSHORE	15129	1,014	792	78%	1,879	(5)	-0%	(9)	213	(16)	464
WL -	WILLISTON BASIN	2732	343	221	64%	42	(1)	-2%	(5)	34	(6)	76
FR -	ROCKY MOUNTAIN FORELAND	7411	476	389	82%	566	(2)	-0%	(8)	106	(13)	287
SJB -	SAN JUAN BASIN	15235	1,379	926	67%	388	(3)	-1%	(29)	199	(32)	425
TB -	OVERTHRUST BELT	120	4	2	50%	159	0	NA	(0)	2	(0)	4
JN -	MID-CONTINENT	53095	4,856	3,920	81%	2,799	(17)	-1%	(58)	688	(83)	1,468
JS -	PERMIAN BASIN	11794	954	776	81%	853	(3)	-0%	(9)	161	(16)	382
L -	WEST COAST ONSHORE	1179	47	94	200%	112	(1)	-1%	(2)	49	(2)	50
	ONSHORE TOTAL:	257,509	13,883	56,880	410%	9,819	(110)	-1%	(564)	2,297	(875)	5,482
OFFSHORE:												
B0 -	OFFSHORE NORPHLET TREND	10	0	0	NA	140	(1)	-1%	0	0	0	0
EGO -	GULF OF MEXICO OFFSHORE	3600	184	0	0%	4,263	(2)	-0%	0	0	0	7
LO -	WEST COAST OFFSHORE	17	0	0	NA	246	0	0%	(0)	2	(2)	35
	OFFSHORE TOTAL:	3,627	184	0	0%	4,649	(3)	-0%	(0)	3	(2)	42
	TOTAL:	261,136	14,067	56,880	404%	14,468	(113)	-1%	(564)	2,300	(877)	5,524

15-Jun

Reference Case 1
Table 15

NATIONAL PETROLEUM COUNCIL ENVIRONMENTAL REGULATION HIGH IMPACT SCENARIO
EXISTING WELLS. COST ESCALATED BY 4%/YR AFTER 1996
$3.50 STANDALONE RUN (HIGH REFERENCE)

$1.67/MMBTU 1989$ WELLHEAD GAS PRICE (1996)
MAXIMUM GAS PRICE $3.50/MMBTU BY YEAR 2014
LIFE OF WELL PAYOUT (7% ROR)
FIRST YEAR IMPACT:

$1.67/MMBTU 1989$ WELLHEAD GAS PRICE (1996)
MAXIMUM GAS PRICE $3.50/MMBTU BY YEAR 2014
LIFE OF WELL PAYOUT (7% ROR)
TOTAL IMPACT FIRST TWENTY YEARS:

HYDROCARBON MODEL REGIONS, (ONSHORE) :		STARTING WELL TOTALS	BASE WELLS UNECON	ADDITIONAL WELLS ABND	ADDITIONAL WELLS %	BASE PROD (BCF)	DELTA PROD. (BCF)	DELTA PROD. %	DELTA RESERVES (BCF)	ADDED COST ($MM)	DELTA RESERVES (BCF)	ADDED COST* ($MM)
A -	APPALACHIA	117330	0	84,477	NA	569	(168)	-30%	(1,549)	663	(2,642)	2,021
B -	EAST GULF ONSHORE (MAFLA)	2319	152	396	261%	210	(2)	-1%	(10)	82	(27)	194
C -	NORTH CENTRAL (MIDWEST)	2856	432	656	152%	96	(3)	-3%	(16)	86	(43)	207
D -	ARKLA-TEXAS	25836	4,147	8,002	193%	1,146	(37)	-3%	(152)	588	(378)	1,388
E -	SOUTH LOUISIANA ONSHORE	2473	79	447	566%	1,000	(9)	-1%	(57)	359	(266)	1,629
G -	TEXAS GULF ONSHORE	15129	1,014	2,269	224%	1,879	(18)	-1%	(66)	591	(284)	1,432
WL -	WILLISTON BASIN	2732	343	600	175%	42	(2)	-5%	(29)	69	(89)	183
FR -	ROCKY MOUNTAIN FORELAND	7411	476	1,199	252%	566	(7)	-1%	(70)	287	(211)	872
SJB -	SAN JUAN BASIN	15235	1,379	2,317	168%	388	(9)	-2%	(164)	379	(390)	1,122
TB -	OVERTHRUST BELT	120	4	2	50%	159	0	NA	(0)	4	(0)	12
JN -	MID-CONTINENT	53095	4,856	9,361	193%	2,799	(47)	-2%	(305)	1,454	(919)	3,959
JS -	PERMIAN BASIN	11794	954	3,055	320%	853	(10)	-1%	(57)	433	(189)	1,168
L -	WEST COAST ONSHORE	1179	47	141	300%	112	(1)	-1%	(4)	47	(14)	108
	ONSHORE TOTAL:	257,509	13,883	112,922	813%	9,819	(313)	-3%	(2,479)	5,042	(5,451)	14,296
OFFSHORE:												
B0 -	OFFSHORE NORPHLET TREND	10	0	0	NA	140	(1)	-1%	0	3	(7)	28
EGO -	GULF OF MEXICO OFFSHORE	3600	184	171	93%	4,263	(9)	-0%	(25)	402	(574)	2,541
LO -	WEST COAST OFFSHORE	17	0	1	NA	246	0	0%	(0)	14	(33)	145
	OFFSHORE TOTAL:	3,627	184	172	93%	4,649	(10)	-0%	(25)	418	(613)	2,714
	TOTAL:	261,136	14,067	113,094	804%	14,468	(323)	-2%	(2,504)	5,460	(6,063)	17,010

Reference Case 2
Table 16

NATIONAL PETROLEUM COUNCIL ENVIRONMENTAL REGULATION LOW IMPACT SCENARIO
EXISTING WELLS
$2.50 STANDALONE RUN (LOW REFERENCE)

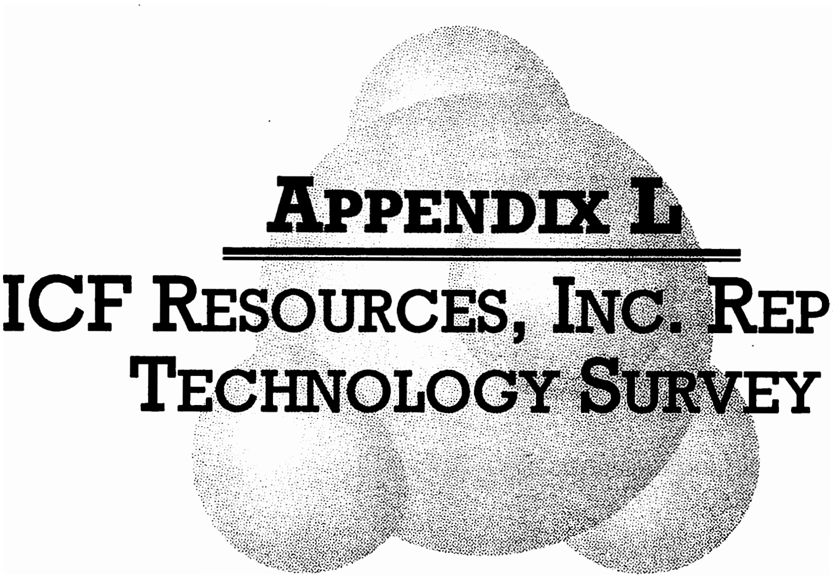
$1.67/MMBTU 1989$ WELLHEAD GAS PRICE (1996)
MAXIMUM GAS PRICE $2.50/MMBTU BY YEAR 2003
LIFE OF WELL PAYOUT (7% ROR)

				FIRST YEAR IMPACT:							TOTAL IMPACT FIRST TWENTY YEARS:	
HYDROCARBON MODEL REGIONS, (ONSHORE) :		STARTING WELL TOTALS	BASE WELLS UNECON	ADDITIONAL WELLS ABND	ADDITIONAL WELLS %	BASE PROD (BCF)	DELTA PROD. (BCF)	DELTA PROD. %	DELTA RESERVES (BCF)	ADDED COST ($MM)	DELTA RESERVES (BCF)	ADDED COST* ($MM)
A -	APPALACHIA	117330	0	44,585	NA	569	(58)	-10%	(394)	346	(667)	1,234
B -	EAST GULF ONSHORE (MAFLA)	2319	152	187	123%	210	(1)	-0%	(2)	32	(4)	74
C -	NORTH CENTRAL (MIDWEST)	2856	432	306	71%	96	(1)	-1%	(3)	34	(6)	78
D -	ARKLA-TEXAS	25836	4,147	4,746	114%	1,146	(18)	-2%	(47)	267	(69)	556
E -	SOUTH LOUISIANA ONSHORE	2473	79	124	157%	1,000	(1)	-0%	(4)	164	(11)	349
G -	TEXAS GULF ONSHORE	15129	1,014	846	83%	1,879	(6)	-0%	(10)	212	(25)	460
WL -	WILLISTON BASIN	2732	343	221	64%	42	(1)	-2%	(5)	34	(8)	76
FR -	ROCKY MOUNTAIN FORELAND	7411	476	389	82%	566	(2)	-0%	(8)	106	(16)	286
SJB -	SAN JUAN BASIN	15235	1,379	926	67%	388	(3)	-1%	(29)	199	(33)	425
TB -	OVERTHRUST BELT	120	4	2	50%	159	0	NA	(0)	2	(0)	4
JN -	MID-CONTINENT	53095	4,856	3,920	81%	2,799	(17)	-1%	(58)	688	(102)	1,462
JS -	PERMIAN BASIN	11794	954	892	94%	853	(4)	-0%	(11)	159	(21)	378
L -	WEST COAST ONSHORE	1179	47	118	251%	112	(1)	-1%	(3)	48	(3)	48
	ONSHORE TOTAL:	257,509	13,883	57,262	412%	9,819	(113)	-1%	(574)	2,290	(962)	5,430
OFFSHORE:												
B0 -	OFFSHORE NORPHLET TREND	10	0	0	NA	140	(1)	-1%	0	0	0	0
EGO -	GULF OF MEXICO OFFSHORE	3600	184	0	0%	4,263	(2)	-0%	0	0	0	7
LO -	WEST COAST OFFSHORE	17	0	0	NA	246	0	0%	(0)	2	(2)	35
	OFFSHORE TOTAL:	3,627	184	0	0%	4,649	(3)	-0%	(0)	3	(2)	42
	TOTAL:		14,067	57,262	407%	14,468	(116)	-1%	(574)	2,293	(964)	5,472

Reference Case 2
Table 17

NATIONAL PETROLEUM COUNCIL ENVIRONMENTAL REGULATION HIGH IMPACT SCENARIO
EXISTING WELLS. COST ESCALATED 4%/YR AFTER 1996
$2.50 STANDALONE RUN (LOW REFERENCE)

HYDROCARBON MODEL REGIONS, (ONSHORE) :		STARTING WELL TOTALS	BASE WELLS UNECON	$1.67/MMBTU 1989$ WELLHEAD GAS PRICE (1996) MAXIMUM GAS PRICE $2.50/MMBTU BY YEAR 2003 LIFE OF WELL PAYOUT (7% ROR) FIRST YEAR IMPACT: ADDITIONAL WELLS ABND	ADDITIONAL WELLS %	BASE PROD (BCF)	DELTA PROD. (BCF)	DELTA PROD. %	DELTA RESERVES (BCF)	ADDED COST ($MM)	$1.67/MMBTU 1989$ WELLHEAD GAS PRICE (1996) MAXIMUM GAS PRICE $2.50/MMBTU BY YEAR 2003 LIFE OF WELL PAYOUT (7% ROR) TOTAL IMPACT FIRST TWENTY YEARS: DELTA RESERVES (BCF)	ADDED COST* ($MM)
A -	APPALACHIA	117330	0	86,824	NA	569	(179)	-31%	(1,681)	616	(2,753)	1,863
B -	EAST GULF ONSHORE (MAFLA)	2319	152	424	279%	210	(2)	-1%	(11)	81	(29)	191
C -	NORTH CENTRAL (MIDWEST)	2856	432	713	165%	96	(3)	-3%	(19)	83	(49)	200
D -	ARKLA-TEXAS	25836	4,147	8,181	197%	1,146	(39)	-3%	(163)	580	(406)	1,365
E -	SOUTH LOUISIANA ONSHORE	2473	79	450	570%	1,000	(10)	-1%	(58)	359	(282)	1,605
G -	TEXAS GULF ONSHORE	15129	1,014	2,349	232%	1,879	(18)	-1%	(70)	587	(313)	1,408
WL -	WILLISTON BASIN	2732	343	653	190%	42	(2)	-5%	(34)	67	(98)	177
FR -	ROCKY MOUNTAIN FORELAND	7411	476	1,249	262%	566	(8)	-1%	(76)	284	(238)	859
SJB -	SAN JUAN BASIN	15235	1,379	2,477	180%	388	(10)	-3%	(185)	373	(430)	1,106
TB -	OVERTHRUST BELT	120	4	2	50%	159	0	NA	(0)	4	(0)	12
JN -	MID-CONTINENT	53095	4,856	9,815	202%	2,799	(50)	-2%	(338)	1,437	(1,018)	3,896
JS -	PERMIAN BASIN	11794	954	2,178	228%	853	(10)	-1%	(61)	429	(199)	1,152
L -	WEST COAST ONSHORE	1179	47	141	300%	112	(1)	-1%	(4)	47	(15)	108
	ONSHORE TOTAL:	257,509	13,883	115,456	832%	9,819	(332)	-3%	(2,700)	4,948	(5,831)	13,943
OFFSHORE:												
B0 -	OFFSHORE NORPHLET TREND	10	0	0	NA	140	(1)	-1%	0	3	(7)	28
EGO -	GULF OF MEXICO OFFSHORE	3600	184	171	93%	4,263	(9)	-0%	(25)	402	(625)	2,513
LO -	WEST COAST OFFSHORE	17	0	1	NA	246	0	0%	(0)	14	(37)	138
	OFFSHORE TOTAL:	3,627	184	172	93%	4,649	(10)	-0%	(25)	418	(669)	2,679
	TOTAL:		14,067	115,628	822%	14,468	(342)	-2%	(2,725)	5,366	(6,500)	16,622



APPENDIX L

ICF RESOURCES, INC. REPORT TECHNOLOGY SURVEY

Summary of Findings from 1992 NPC Exploration & Production R&D Survey

July 6, 1992

Introduction and Purpose

A major objective of the Source and Supply Task Group is to recommend priorities for future federal upstream R&D that would reduce constraints on production and utilization of natural gas. These priorities must be based on an understanding of the scope and magnitude of current industry R&D and their recommended priorities for federal R&D. The task group decided that a formal survey of the entities conducting the majority of gas related upstream R&D would provide the consistency and credibility upon which to base such recommendations.

Analysis Method

The survey was limited to 25 companies expected to be the principal users of advanced natural gas E&P technology and those conducting significant natural gas-related E&P R&D. These included 17 operators, 2 R&D organizations and 6 service companies. In addition to soliciting data on current (1992) R&D operations, the survey also asked for data on 1988 operations to allow calibration with the results of a 1988 NPC R&D survey.[1] Survey results were aggregated, analyzed and are summarized below. Task group policy and R&D recommendations are not described in this report.

The survey form and list of companies surveyed are included at the end of this appendix. All 25 companies responded to the survey. Respondents with significant ongoing R&D programs included 12 of the 17 operators, 1 of the 2 R&D organizations and 3 of the 6 service companies. Data were aggregated and analyzed by type of respondent (operator, R&D or service company) to distinguish different patterns of R&D expenditure growth and desired federal R&D priorities.

Findings

Each of the questions will be discussed below in terms of aggregate survey data, trends compared to 1988 data and implications for industry or federal R&D policy recommendations. Because R&D organizations make up less than 5 percent of total R&D expenditures, they are not discussed separately below.

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[1] National Petroleum Council, *Integrating R&D Efforts,* June 1988.

Allocation of R&D Expenditures by Product

Aggregate R&D expenditures in 1992 for the survey group were $1,429 million, compared to $1,218 million for 1988, a 17 percent increase in nominal dollars, and unchanged in real dollars. This increase was concentrated in the service companies ($472 million in 1992, up 42 percent from $333 million in 1988), who indicated they were mostly rebuilding to early 1980s levels of expenditures after downsizing in the mid-1980s.

Operating company R&D expenditures increased only 5 percent, from $891 million from $851 million in 1988. Current operator R&D expenditures are concentrated in a few companies. The three largest R&D budgets make up 53 percent of the 17 company total, and the top 6 companies make up 78 percent of total R&D expenditures. Because of this concentration, the expenditure trends of the companies with large R&D expenditures disproportionately influence the trends in aggregate data.

Where possible, companies indicated allocations of R&D expenditures among oil-related and gas-related efforts. Operators reported that 39 percent of R&D dollars was directed to oil, 13 percent to gas, and the remaining 48 percent was judged non-allocable. Within service companies, 93 percent of R&D was judged to be non-allocable.

Allocation of R&D Expenditures by Type

One hypothesis was that recent cuts in capital expenditures and reductions in staff would force companies to reduce basic research and proportionately increase technical support services for field operations. Also, environmental compliance R&D was expected to have increased significantly over the 1988-92 period.

In 1988, operators allocated 57 percent to research, 42 percent to technical support and 1 percent to environmental compliance. By 1992, these priorities had changed very little, with basic research making up 54 percent of R&D budgets, technical support at 41 percent and environmental compliance at 5 percent.

Service companies in 1988 allocated 27 percent to basic research, 71 percent to technical support and 2 percent to environmental compliance. By 1992, these allocations had shifted to 31 percent, 65 percent and 4 percent, respectively. Growth in basic research for the service companies resulted from overall increases in R&D expenditures, rather than at the expense of technical support.

The overall R&D expenditures of $1,218 million in 1988 and $1,429 million in 1992 are not directly comparable with data from the 1988 study. That study only included expenditures for basic R&D and excluded technical support. Therefore, $1,218 million total funding and a 50 percent R&D allocation indicates 1988 basic research expenditures of $609 million, compared to the 1988 survey total of $811 million. This discrepancy may be due to either different sample populations or different reporting bases among respondents.

By the same method, $697 million would have been spent on basic R&D, derived from a 49 percent research share of $1,429 million total R&D expenditures. This 15 percent nominal dollar increase is comparable to overall and company type expenditure trends described above.

Thus, there is no empirical basis to support the hypothesis of a shift from basic research to technical support over the 1988 to 1992 period.

Allocation of R&D Expenditures by Performing Entity

A second hypothesis and an expected trend predicted by the 1988 NPC study was an increase in the proportion of collaborative R&D as a means to leverage R&D budgets. Among operators, 96 percent of R&D was conducted at a company's own facilities in both 1988 and 1992. Since most R&D expenditures are for salaries, it is counter-intuitive that companies undergoing staff reductions would fund R&D consortia or academic programs at the expense of retaining their own staff.

Service companies share of in-house R&D decreased from 96 percent in 1988 to 91 percent in 1992. As for allocation of R&D by type, the increase in consortia and academic R&D came from overall growth in R&D expenditures rather than at the expense of company R&D. Therefore, the second hypothesis also is not supported by the survey data.

R&D Staffing

Overall R&D staffing grew slightly over the 1988-92 period, from 8,600 to 8,900 full-time, on staff personnel. Operator R&D staffs decreased by 16 percent, from 5,300 to 4,500, while service company staffs increased 35 percent, from 3,300 to 4,400. As mentioned above, this increase in staff levels was largely due to rebuilding following the downsizing of the mid-1980s.

Among the service companies, some of the growth was the result of acquisitions of smaller geophysical and related equipment companies since 1988. These do not significantly affect interpretation of the results or comparison with the 1988 NPC survey because the largest companies were already included in the 1988 survey and many service company respondents both bought as well as sold subsidiaries during 1988-92.

Federal R&D Priorities

Respondents were asked to rate six areas of potential federal R&D by level of importance (on an ordinal scale of low, medium, or high). There were four technology-related areas:

- Exploration/Resource Appraisal
- Reservoir Evaluation/Characterization
- Drilling and Completion Technology
- Production/Field Management

and two topical areas:

- Unconventional Gas
- Environmental Technology.

Company rankings were totaled within each priority class. The rankings showed clear preferences of high and low importance for federal R&D, preferences that were consistent between operator and service company groups.

High priority rankings were given to Reservoir Evaluation/Characterization and Environmental Technology. Low rankings were given to the Drilling and Completion Technology and the Production/Field Management categories. Both Exploration/ Resource Appraisal and Unconventional Gas were ranked lower than average priority for federal R&D.

Conclusions

Analysis of survey data led to three conclusions:

- R&D expenditures between 1988 and those planned for 1992 held steady. This conclusion may be misleading because many of the reductions in R&D expenditures may not become apparent in company budgets until later this year or in planned expenditures for next year. Respondents indicated, however, that 1992 data were current budgeted values and not estimates made in 1991. At the end of this year, the full effect of recent downsizing might be empirically evident.

- There is no demonstrable shift to collaborative research, as was expected in 1988. This is logical, since companies would preferentially fund their own staff before spending money on outside R&D operations, unless R&D expenditures were increasing.

- Company priorities for federal R&D are consistent among operator and service sectors of the industry. Companies feel that federal research should focus on reservoir evaluation and environmental technologies and minimize involvement in drilling and production technology research.

National Petroleum Council
Natural Gas Upstream R&D Survey
(May 1992)

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1. Estimate your company's past and current oil and gas E&P R&D expenditures ($ millions). These expenditures should include only those amounts derived from your company and exclude monies spent on R&D at your facilities from government or other private sources.

	1988	1992
Oil	$	$
Gas	$	$
Not Allocable	$	$
Total E&P R&D	$	$

2. Indicate significant allocations of your organization's overall E&P R&D expenditures from your answer to Question 1.

	1988	1992
Company R&D	%	%
Funding for Industry R&D Consortia	%	%
Funding for Academic Research	%	%
Other (Specify________________________)	%	%
Total E&P R&D Expenditures	100%	100%

3. Estimate staffing (full time equivalent personnel) for 1988 and current R&D operations.

	1988	1992
Total R&D Staff		

4. The aggregate estimated E&P R&D expenditures of the 25 surveyed companies should constitute a majority of total domestic oil and gas E&P R&D. What proportion of <u>total</u> private sector and institutional E&P R&D expenditures do you think this aggregate estimate represents?

	1988	1992
Survey % of Total E&P R&D	%	%

5. Please specify the allocation of your company's E&P R&D expenditures shown in your answer to Question 1 above.

	1988	1992
Research	%	%
Technical Support Services	%	%
Environmental Compliance	%	%
Total R&D	100%	100%

National Petroleum Council
Natural Gas Upstream R&D Survey
(May 1992)

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6. What priorities would you recommend that the federal government place on its future natural gas E&P related R&D? Please check one priority level for each item.

	Low	Medium	High
Exploration/Resource Appraisal			
Reservoir Evaluation/Characterization			
Drilling and Completion Technology			
Production/Field Management Practice			
Unconventional Gas Technology			
Environmental Technology			

Who should we contact if we need clarification with the survey responses?

Name ____

Telephone (______) _______________________________

Please return completed survey forms by Friday, May 22 to:

Mark R. Haas
ICF Resources
9300 Lee Highway
Fairfax, VA 22031-1207
Phone: (703) 934-3847
Telecopy: (703) 691-3349

National Petroleum Council
Natural Gas Upstream R&D Survey
(May 1992)

DEFINITIONS

Expenditures - R&D costs include a reasonable allocation of indirect costs. However, general and administrative costs that are not clearly related to research and development activities should not be included.

R&D Staffing - Technical personnel (scientists, engineers, direct technical support and first line supervision) employed in your research effort. Only those included in full-time research should be included. Do not include field support personnel.

Research - Planned search or critical investigation aimed at discovery of new knowledge with the hope that such knowledge will be useful in developing a new product or service, or a new process or technique, or in bringing about a significant improvement to an existing product or process.

Technical Support Services - Routine or periodic alterations to existing products, production lines and manufacturing processes in support of ongoing field operations. It includes adaptation of existing products or processes to improve technical or cost efficiency but excludes generic scientific inquiry that is included as part of the research function.

Environmental Compliance - Research uniquely targeted to reduction, elimination, remediation or monitoring of emissions, discharges or other products of E&P operations that are covered or are expected to be governed by federal or state environmental regulations.

1992 - Answers to questions pertaining to "1992" should represent the level of company effort at the conclusion of any current program of change.

Appendix M

Suggested R&D Projects for Joint Industry/Government Sponsorship

AIR EMISSIONS CONTROL TECHNOLOGY

Implementation of the Clean Air Act Amendments for the exploration and production portion of the natural gas industry will place a burden on companies to inventory, evaluate, and minimize air emissions. A large quantity of clean-air technology already exists for the natural gas industry. A technology transfer effort aimed at companies of all sizes would disseminate the required information, speed compliance, and reduce costs associated with the retrofit of the required technology. An even larger quantity of clean-air technology exists for allied industries, such as coal combustion. Studies to adapt applicable clean-air technology from these industries could be a very cost-effective way to achieve required standards in the natural gas industry.

AIR EMISSIONS INVENTORY/MODELING

Although a clear strategy for implementation of the Clean Air Act Amendments is not evident, most agree that an accurate air emissions inventory will be the key for a company to conform to these regulations. Most air emissions for the exploration and production industry are based on calculations as opposed to analytical measurements. These calculations are subject to significant errors as a result of the inaccuracies of assumptions required for the calculations. Studies are needed to identify ways to make more accurate analytical measurements and approximations of emissions. Regulators and natural gas companies will both benefit from having an accurate measurement tool that does not change radically with time.

PRODUCED WATER TREATMENT

The salt and hydrocarbon content of produced waters make disposal in onshore and offshore operations very difficult and costly. Cost effective technologies are needed to allow on-site polishing of produced waters to remove hydrocarbons. These techniques would be required to meet current and anticipated hydrocarbon concentrations for discharge. Many produced waters may have relatively low salt content, posing the possibility of desalination and agricultural utilization. Research into potential methods of desalination, soil loading rates, cat-ion balances, and soil response could provide an effective means for beneficial re-use of produced waters. These produced waters could be transformed from a nuisance waste to a valuable natural resource in arid areas.

DISPOSAL OR INHIBITION OF NORM-CONTAINING SCALE

Naturally occurring radioactive material (NORM) is present in many of the scales that form in natural gas production operations. There are no currently available techniques for legally disposing of NORM-containing wastes. Research may take the form of waste disposal technology or waste minimization. One waste disposal option would call for the re-injection in dissolved or solid form. Research to illustrate the stability of the re-injected materials in the subsurface would assist regulators in making the right decision in terms of NORM injection. A second approach to the problem is waste minimization, achieved by preventing formation of NORM-containing scales. Chemical treatments to prevent scale are well documented; however, the ability to consistently prevent small quantities of NORM scale from forming is questionable. Identification of dependable, cost-effective NORM scale inhibitors could prevent future NORM problems and have a potential impact on gas production as well.

MEMBRANE SEPARATION RESEARCH

This is probably the most promising area for advances in sub-quality natural gas treatment (i.e., CO_2, H_2S, H_2O, and N_2 removal). Membrane manufacturers consider natural gas treatment a niche market and are not likely to expend a great deal on R&D for this area. A program in this area should include further funding of basic materials research as well as lab and/or pilot scale testing of new materials for commercial application. This may be done as an augmentation of on-going work by the Department of Energy or the Gas Research Institute.

REDOX PROCESSES FOR H_2S CONVERSION TO ELEMENTAL SULFUR

This program also stems from environmental concerns with the removal and disposal of H_2S from either natural gas directly or amine system acid gas. Current commercial redox processes produce a low-quality waste sulfur stream of little or no value. Alternative processes have been proposed that would produce high-quality, easily marketed sulfur. A program in this area should target these processes for validation and testing.

RESERVOIR CHARACTERIZATION FOR ADVANCED GAS RECOVERY

Access to conventional and nonconventional natural gas resources using advanced technologies is increasingly dependent on understanding the physical framework that was determined when reservoir rocks were originally deposited and subsequently consolidated and cemented. Developing this understanding is a key part of reservoir characterization. In tight gas sandstones, propagation of the hydraulic fracture is dependent on physical properties of the cemented sandstone as well as its thickness and lateral extent. Emplacing a hydraulic fracture across rock type boundaries and pre-existing fractures is not yet entirely predictable, and additional work is needed in fracture diagnostics and fracture fluid characteristics. In conventional reservoirs, drilling over the last decade has revealed reservoir heterogeneities that compartmentalize reservoirs leaving unrecovered gas in place. Thus, mature reservoirs may be abandoned unless reservoir compartmentalization based on flow boundaries can be recognized through an integrated program of advanced reservoir development. Reservoirs specifically amenable to this type of reserve growth have substantial remaining resource potential accessible through strategic infill drilling and, where reservoirs are vertically stacked, through well recompletions.

GAS TO HYDROCARBON LIQUIDS

Large quantities of natural gas are located in remote areas, such as Prudhoe Bay, where transportation costs make it prohibitive to bring it to market. Basic research is needed to develop and commercialize catalytic methane conversion processes that produce refinery-compatible liquids. A straightforward isobaric process could minimize the capital expenses associated with the methane-to-crude oil process.

A COMPREHENSIVE STUDY OF LIQUID LOADING IN NATURAL GAS WELLS

A comprehensive study involving field data, laboratory experiments, model tests, and mathematical models could be used to better define the rate at which liquids cannot be lifted from gas wells. Most gas wells produce some associated water which, as gas rates per well decline, can kill the well if these waters are not lifted to the surface. The most applicable technical work concerning predicting liquid loading rates in gas wells is more than 20 years old and did not cover large tubing sizes or deviated wells. Recently, a field study done by Exxon found that correlations from that work tended to under predict the loading rate by an average of 20 percent. Correctly predicting this information could add years to the productive lives of gas wells and allow significant increases in ultimate recoveries from gas reservoirs.

IMPROVED TECHNIQUES FOR QUANTITATIVELY CHARACTERIZING LOW-POROSITY, LOW-PERMEABILITY, AND FRACTURED RESERVOIRS

Many of the remaining gas reserves are located in tight formations. The industry currently cannot accurately measure the characteristics of these reservoirs with respect to porosity, permeability, and gas saturation. For example, currently accuracy for determining porosity from downhole measurements is + 40 percent in reservoirs of 5 porosity units. It is, therefore, difficult to determine reserves in these tight formations, making development decisions difficult. It is also difficult to characterize natural or induced fractures in these reservoirs. Research needs to be conducted in several areas to improve the ability to accurately characterize these reservoirs. From an exploration standpoint, it is also desirable to be able to predict variations in reservoir quality from seismic or other methods prior to drilling so that drilling can be focused on the better parts of the reservoir.

GAS GENERATION AND MIGRATION

Part of the industry's inability to explore specifically for gas is due to a poor ability to type gas back to specific source rocks, understand the specific kinetic reactions and temperature of formation of gas of thermogenic origin in different geographic areas, understand when biogenic gas is likely to be formed in economic accumulations, and understand gas versus oil migration on a basin scale. Research in these areas could provide tools to assist in developing the understanding of gas generation, migration, and entrapment which would allow for a better ability to intelligently explore for gas. This work would also provide a greater understanding of the chemistry of the gas encountered in various areas.

GAS PROCESSING

Research in this area could be focused on improved methods of removing undesirable components from gas production streams, on producing and transporting gas from low pressure reservoirs, and new and innovative ways of storing gas in areas where it is most needed.

U.S. NATURAL GAS RESOURCE BASE PERIODIC ASSESSMENT

Several organizations, such as the Potential Gas Committee, the U.S. Geological Survey, and other government-associated, academic, and private groups have from time to time made estimates of the total U.S. hydrocarbon and natural gas resources. Annually the Department of Energy, through the Energy Information Agency, compiles and summarizes statistics on the cumulative production and proved reserves for the U.S. gas industry. In addition, periodically special studies, such as the 1992 NPC natural gas study are commissioned. The Department of Energy should take on the responsibility and administration of a coordinated resource assessment at a regular time interval (i.e., every three years). This effort should involve all aspects of the natural gas industry, and should bring together private industry, government, and academic experts to bring the assessment of the resource, by category, up to date. Results of this assessment should be published for public use, and give likely resource values by type (i.e., conventional high and low permeability, tightgas, coalbed methane, shale, etc.) and geographic location by basin. This assessment could start with the 1992 NPC developed values and categories and build from there.

ESTABLISH A CLEARING HOUSE FOR TECHNOLOGY DISSEMINATION

The Department of Energy should establish technology centers at locations in or near gas field operations, where information on new and evolving technologies in drilling, formation evaluation, completion, stimulation, production, processing, and transportation are made available to all of industry. A key to technology transfer to all industry in a timely manner is information in a usable and readily available format. It might also require some professional interpretation for applicability to specific situations.

ESTABLISH AND JOINTLY SPONSOR FORUMS FOR THE DISCUSSION AND EXCHANGE OF INFORMATION ON ALL ASPECTS OF THE UPSTREAM GAS BUSINESS

In association with technical or industry sponsored groups, create a forum for the exchange of operating as well as technical information on the upstream gas industry. This exchange would stimulate the dissemination of low cost and effective practices. From such a forum, focused programs might be initiated and directed for specific research and field testing.

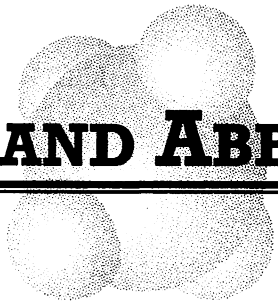
MULTI-PHASE FLUID COMPRESSION / PUMPING RESEARCH AND DEVELOPMENT

Sponsor research and development for modularized, multi-phase fluid pressure boosters, which would help make more gas production available from multi-point, isolated systems.

OTHER OPPORTUNITIES

- Develop a method for water shutoff in the formation.
- Develop a method for accurately measuring the flux of hydrocarbons from surface facilities in the field.
- Develop a technique for remotely sensing "Sweet Spots" in naturally fractured reservoirs.
- Devise a method to prevent gas flow just after cementing.
- Develop acid stimulation techniques for deep, hot, sour gas reservoirs.
- Evolve interpretation techniques to relate quantitative surface gas measurements to formation fluid content.
- Improve cementing techniques or formulations to prevent gas leakage through cement after development of compressive strength.
- Develop selection criteria for horizontal wells in gas reservoirs.

ACRONYMS AND ABBREVIATIONS



ACE	adjusted current earnings
AFUE	Average Fuel Utilization Efficiency
AGA	American Gas Association
AGCC	American Gas Cooling Center
AGS	Alberta Geological Society
AMT	Alternative Minimum Tax
ANGTS	Alaskan Natural Gas Transportation System
ANWR	Arctic National Wildlife Refuge
API	American Petroleum Institute
ATEPD	Alternative Tax Energy Preference Deductions
BCF	billion cubic feet
BCF/D	billion cubic feet per day
BCM	billion cubic meters
B/D	barrels per day
BLM	Bureau of Land Management
BOE	barrels of oil equivalent
BTU	British thermal units
CAA	Clean Air Act of 1967
CAAA	Clean Air Act Amendments of 1990
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980
CERI	Canadian Energy Research Institute
CFC	chlorofluorocarbons
CLEV	California Low Emission Vehicle Regulations
CNG	compressed natural gas
CNR	Columbia Natural Resources
CO_2	carbon dioxide
COPAS	Council of Petroleum Accounting Societies
CWA	Clean Water Act of 1977
D&C	drilling and completion (costs)
DCF	Discounted Cash Flow
DFI	Decision Focus Inc.
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DRI	Data Resources Incorporated
DSM	Demand Side Management

E&P	exploration and production (costs)
EEA	Energy and Environmental Analysis, Incorporated
EEI	Edison Electric Institute
EIA	Energy Information Administration
EMF	Electric and Magnetic Field
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
EPACT	Energy Policy Act of 1992
EPRI	Electric Power Research Institute
ERCB	Alberta Energy Resources Conservation Board
ERM	Enhanced Recovery Module of the Hydrocarbon Model
EUR	estimated ultimate recovery
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission
FRB Index	Federal Reserves Boards' Index of Total Industrial Production
G&G	geological and geophysical (expenditures)
GATT	General Agreement on Tariffs and Trade
GEMS	Generalized Equilbrium Modeling System
GRI	Gas Research Institute
HDD	heating degree days
HSM	Hydrocarbon Supply Model
HVAC	Heating, Ventilating, and Air Conditioning
IDC	Intangible Drilling Costs
IEA	International Energy Agency
IGTCC	Industrial Gas Technology Commercialization Center
INGAA	Interstate Natural Gas Association of America
IOGCC	Interstate Oil and Gas Compact Commission
IPAA	Independent Petroleum Association of America
IPP	independent power producer
IRP	integrated resource planning
JAS	Joint Association Survey
KW	kilowatts
KWH	kilowatt hours
LAER	lowest achievable emission rate (controls)
LCP	least cost planning
LDC	local distribution company
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MAFLA	Mississippi, Alabama, Florida onshore
MCF	thousand cubic feet
MCF/D	thousand cubic feet per day
MECS	Manufacturing Energy Consumption Survey
MMBTU	million British thermal units
MMCF	million cubic feet
MMCF/D	million cubic feet per day
MMS	Minerals Management Service, Department of Interior

MOPPS (I&II)	Market Oriented Program Planning Study
MPRSA	Marine Protection, Research and Sanctuaries Act, 1972
MW	megawatts
MWH	megawatt hours
NAAQS	National Ambient Air Quality Standards
NAECA	National Appliance Energy Conservation Act
NAFTA	North American Free Trade Agreement
NARG	North American Regional Gas Model
NARUC	National Association of Regulatory Utility Commissioners
NEB	National Energy Board of Canada
NEPA	National Environmental Policy Act of 1969
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NES	National Energy Strategy
NGA	Natural Gas Act of 1938
NGL	natural gas liquids
NGPA	Natural Gas Policy Act of 1978
NGSA	Natural Gas Supply Association
NGV	Natural Gas Vehicle
NGVC	Natural Gas Vehicle Coalition
NGWDA	Natural Gas Wellhead Decontrol Act of 1989
NIMBY	Not In My Back Yard
NMS	National Marine Sanctuary Program
NORM	naturally occurring radioactive material
NOx	nitrogen oxides
NPC	National Petroleum Council
NPDES	National Pollutant Discharge Elimination System
NRRI	National Regulatory Research Institute
NUG	non-utility generator
NYGAS	New York State Gas Association
O&M	operating and maintenance (expenses)
OCS	Outer Continental Shelf
OGIFF	Oil and Gas Integrated Field File
OPA	Oil Pollution Act of 1990
OPEC	Organization of Petroleum Exporting Countries
PEMEX	Petroleos Mexicanos, national oil company of Mexico
PGC	Potential Gas Committee of the Colorado School of Mines
PIFUA	Powerplant and Industrial Fuel Use Act of 1978
PMA	Federal Power Marketing Agencies
PSC	Public Service Commission
PUC	Public Utility Commission
PUCHA	Public Utilities Holding Company Act
QBTU	quadrillion British thermal units
RACC	Refiners Acquisition Cost of Crude Oil

RCRA	Resource Conservation and Recovery Act of 1976
R&D	research and development
RD&D	research, development, and demonstration
RECS	Residential Energy Consumption Survey
ROR	rate of return
SARA	Superfund Amendments and Reauthorization Act of 1986
SCF	standard cubic feet
SDWA	Safe Drinking Water Act of 1984
SEC	Securities and Exchange Commission
SEDS	State Energy Data System
SFV	straight fixed variable
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SMP	special marketing program
SO_2	sulfur dioxide
SOx	sulfur oxides
SPP	small power producer
TAGS	Trans-Alaska Gas System
TAPS	Trans-Alaska Pipeline System
TBTU	trillion British thermal units
TCF	trillion cubic feet
TRC	Texas Railroad Commission
TSCA	Toxic Substance Control Act of 1976
UDI	Utility Data Institute
UIC	Underground Injection Control program
USGS	United States Geological Survey
VOC	volatile organic compounds
WCSB	Western Canada Sedimentary Basin

GLOSSARY

ABANDONMENT

When an interstate pipeline closes facilities, stops transporting gas in interstate commerce, or stops sales of gas for resale with permission of the Federal Energy Regulatory Commission.

ALASKA NATURAL GAS Transportation (ANGTS)

A proposed pipeline to transport gas from Prudhoe Bay, Alaska, to the lower-48 states. Portions of the line were "prebuilt" prior to the flow of Alaskan gas, with the rest of the system awaiting sponsors and economically viable gas prices.

ALLOWABLE

The maximum amount of gas a specific field, lease, or well is permitted to produce.

ALTERNATIVE MINIMUM TAX (AMT)

Under the Tax Reform Act of 1986 the minimum tax was reformulated as the AMT and expanded to the point where it became the *de facto* corporate income tax for many capital-intensive firms. The AMT is imposed at 20 percent rate (24 percent non-corporate) on a broader income than that used for regular income tax, and the taxpayer pays the higher of the two taxes.

AMERICAN GAS ASSOCIATION (AGA)

The gas utility industry trade association.

ANTRIM SHALE

The Antrim shale is a formation of primarily Devonian age located in the Michigan Basin.

ASSOCIATED DISSOLVED GAS

The combined volume of natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

BACK HAUL

A contractual form of natural gas transportation service, where natural gas is delivered to the shipper at a point on the pipeline system which is upstream of the point where gas is received into the system. Contractually, the natural gas is transported against the direction of natural gas flowing in the pipeline system. In most cases this type of service can be provided without the need to construct new facilities, and in operation may actually reduce the variable costs (fuel) incurred by the pipeline to provide transportation service. It also has the effect of increasing the effective capacity of the pipeline system.

BASE GAS

(*See* Cushion Gas.)

BASE LOAD GENERATING UNIT

Those generating units at electric utilities that are normally operated to meet electricity demand on a round-the-clock basis.

BASE RATE

That portion of the total electric rate which covers the general costs of doing business unrelated to fuel expenses.

BCF

Billion Cubic Feet. A volumetric unit of measurement for natural gas.

BLANKET CERTIFICATE (AUTHORITY)

Permission granted by the Federal Energy Regulatory Commission (FERC) for a certificate holder to engage in an activity (such as transportation service or sales) on a self-implementing or prior-notice basis, as appropriate, without case-by-case approval from the FERC.

BRITISH THERMAL UNIT (BTU)

A standard unit for measuring the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit at or near 39.2 degrees Fahrenheit.

CAPACITY BROKERING

A process where an existing natural gas shipper sells or leases its contractual capacity rights to transport natural gas on a pipeline to someone else.

CERTIFICATED CAPACITY

The maximum volume of gas that may be stored in an underground storage facility certificated by the Federal Energy Regulatory Commission or its predecessor, the Federal Power Commission. Absent a certificate, a reservoir's present developed operating capacity is considered to be its "certified" capacity.

CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY

Certificates required under the Natural Gas Act and issued by the Federal Power Commission/Federal Energy Regulatory Commission prior to construction or expansion of an interstate pipeline; after the pipeline showed the existence of market demand and attendant gas supply.

CHRISTMAS TREE

The valves and fittings installed at the top of a gas well to control and direct the flow of well liquids.

CITYGATE

A point or measuring station at which a gas distribution company receives gas from a pipeline company or transmission system.

CITYGATE SALES SERVICE

Interstate pipeline natural gas sales service where the title to gas sold changes at the pipeline's interconnection with the purchasing local distribution company.

COAL GASIFICATION

The process of placing coal steam and oxygen under pressure to produce gas.

COFIRING (REBURNING)

The process of burning natural gas in conjunction with another fuel to reduce air pollutants and/or take advantage of lowest available fuel prices.

COGENERATION

The sequential production of electricity and another form of useful thermal energy such as heat or steam and used for industrial, commercial heating or cooling purposes. There are basically three types; boiler steam turbine, combustion turbine with waste heat recovery steam generator, and combined cycle.

COKE OVEN GAS

The gaseous portion of volatile substance driven off in the coking process after other coal chemicals are removed.

COMBINED CYCLE

An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

COMMERCIAL CONSUMPTION

Gas consumed by nonmanufacturing establishments or agencies primarily engaged in the sale of goods or services. Included are such establishments as hotels, restaurants, wholesale and retail stores, and other service enterprises; gas consumed by establishments engaged in agriculture, forestry, and fishers; and gas consumed by local, state, and federal agencies engaged in nonmanufacturing activities.

CONVENTIONAL RESOURCES

Resources included in this category are crude oil, natural gas, and natural gas liquids that exist in reservoirs in a fluid state amenable to extraction employed in traditional development practices. They occur as discrete accumulations. They do not include resources occurring within extremely viscous and intractable heavy oil deposits, tar deposits, oil shales, coalbed gas, gas in geopressured shales and brines, or gas hydrates. Gas from low-permeability "tight" sandstone and fractured shale reservoirs having in situ permeability to gas of less than 0.1 millidarcy are not included as conventional resources.

COST-OF-SERVICE RATES

A method of rate making used by utilities under which the original cost of facilities are depreciated for an expected life, and the annual costs and the operating and maintenance costs are allocated to each service offered according to a test year and projected volumes.

CROSS SUBSIDIES

Subsidies among customers or customer classes so that one group carries a disproportionate share of the costs of providing service.

CURTAILMENTS

The rationing of natural gas supplies to an end user when gas is in short supply, or when demand for service exceeds a pipeline's capacity, usually to an industrial user and/or power generator.

CUSHION GAS

The volume of gas, including native gas, that must remain in the storage field to maintain adequate reservoir pressure and deliverability rates throughout the withdrawal season.

CYCLING

The process of injecting or withdrawing a percentage or all of a reservoir's working gas capacity during a particular season.

CYCLING UNIT (INTERMEDIATE UNIT)

Units that operate with rapid load changes, frequent starts and stops, but generally at somewhat lower efficiencies and higher operating costs than base load plants. These units are generally either former base load units regulated to cycling units, or newly built units of a lower megawatt rating which require less capital investment per unit of output than required for base load units.

DECATHERM

Ten therms, or 1,000,000 BTU.

DEEP GAS DEPOSITS

Deposits of gas below 15,000 feet, where the porosity and permeability are reduced by the deeply buried sediments.

DELIVERABILITY

The rate at which gas can be withdrawn from an underground reservoir. Actual rates depend on rock characteristics, reservoir pressure, and facilities such as wells, pipelines, and compressors.

DELIVERED

The physical transfer of natural, synthetic, and/or supplemental gas from facilities operated by the responding company to facilities operated by others or to consumers.

DEMAND CHARGE

A charge levied in a contract between a pipeline and local distribution company, electric generator, or industrial user for firm gas pipeline transportation service. The demand charge must be paid whether or not gas is used up to the volume covered by the charge.

DEMAND SIDE MANAGEMENT

Programs designed to encourage customers to use less natural gas or other fuels or less electricity and to use it more efficiently (i.e., conservation) or to reduce peak demand (i.e., load management).

DESIGN DAY CAPACITY

The volume of natural gas that a pipeline facility is designed to transport during one day, given the assumptions used in the design process, such as pressures, pipeline efficiency, and peak hourly rates.

DESIGN DAY DELIVERABILITY

The rate of delivery at which a storage facility is designed to be used when storage volumes are at their maximum levels.

DEVELOPED OPERATING CAPACITY

That portion of operating capacity which is currently available for storage use.

DEVONIAN SHALE

Any body of shale (a fine-grained, detrital, sedimentary rock with a finely laminated structure) formed from the compaction of clays and/or silts and/or middays that were deposited during the Devonian period of the Paleozoic era, from approximately 400 million to approximately 345 million years before the present.

DISPLACEMENT

A method of natural gas transportation/delivery that is similar to a back haul (see above). In a displacement service, natural gas is received by a pipeline at one point and delivers equivalent volumes at another point, without necessarily transporting the natural gas in a line between the two points. Displacement service may contain elements of forward haul, back haul, and displacement to effect delivery.

DRY NATURAL GAS PRODUCTION

Marketed production less extraction loss.

ELECTRIC GENERATORS

Establishments that generate electricity. These include traditional electric utilities; independent power producers; and commercial and industrial establishments that generate electricity for their own use, often using cogeneration facilities, and which may sell some of the electricity to an electric utility for resale. In the NPC report, commercial and industrial generators of electricity are included in the commercial and industrial sectors and all other generators are dealt with under "electric generation."

ELECTRIC UTILITIES

Establishments primarily engaged in the generation, transmission, and/or distribution of electricity for sale or resale.

ELECTRIC UTILITY CONSUMPTION

Gas used as fuel in electric utility plants.

END-USE SECTOR MODELS

Energy and Environmental Analysis, Inc.'s process-engineering models used in the NPC Gas Study and include the Residential, Commercial, Industrial, and Electric Utility Demand Models.

END USER

Anyone who purchases and consumes natural gas.

ENERGY OVERVIEW MODEL

Energy and Environmental Analysis, Inc.'s forecasting model, which simulates the natural gas supply/demand balance through the use of 3 sets of model components (End-Use Sector Models, the Pipeline Model, and the Hydrocarbon Supply Model) and used in the NPC Gas Study.

EXCHANGE

A method of natural gas transportation/delivery among two (or more) parties. Where one party has a natural gas supply at one point, convenient to one pipeline system, and another party has gas at another point, convenient to another pipeline system, a swap is arranged. The two pipelines do not necessarily have to interconnect. Essential to the concept is that both parties receive mutual benefits. Exchange agreements usually contain some form of balancing mechanism requiring either the delivery of natural gas, in kind, or payment.

EXPORTS

Natural gas deliveries from the continental United States and Alaska to foreign countries.

EXTERNALITY

A side effect that can create benefits or costs in a transaction and which fall upon those not directly involved in, or who are external to, the transaction.

EXTRACTION LOSS

The reduction in volume of natural gas due to the removal of natural gas liquid constituents such as ethane, propane, and butane at natural gas processing plants.

FEDERAL POWER COMMISSION (FPC)

The predecessor agency of the FERC, which was created by Congress in 1920 and was charged with regulating the interstate electric power and natural gas industries.

FEDERAL ENERGY REGULATORY COMMISSION (FERC)

A quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification. Five members are appointed by the President of the United States and, upon confirmation by the Senate, serve fixed terms. This independent agency is administered by the Chairman of the five-person commission. No more than three of the five members may belong to the President's political party.

FERC ORDER 436

An order issued October 9, 1985, by the FERC, which created a voluntary blanket certificate transportation program. Under this program, participating pipelines were authorized to provide firm and interruptible transportation to any willing shipper without prior case-specific FERC approval. Pipelines providing this service are required to serve on a non-discriminatory basis any shipper willing to meet the terms and conditions of the pipeline's tariff. Participating pipelines were also subject to a requirement that they allow existing firm sales customers to convert their sales service to firm transportation service.

FERC ORDER 451

Order 451 was issued in 1986 and eliminated old gas "vintaging" pricing, which was based on the date of first production of the gas reserves. The Order established a new ceiling price for all vintages of old gas, which a pipeline purchaser could purchase or release under a procedure called "good faith negotiations."

FERC ORDER 500

In Associated Gas Distributors vs. FERC, Order 436 was remanded back to FERC. In response, FERC issued Order 500 in August 1987, which restated Order 436 with two major changes: elimination of the customer contract demand reduction option, and creation of a take-or-pay crediting mechanism. This mechanism was designed to affect take-or-pay obligations of interstate pipelines caused by Order 436 transportation.

FERC ORDER 490

Order 490 was issued in 1988 and established an expedited abandonment procedure for gas under expired or terminated contracts.

FERC ORDER 636 (*SEE ALSO* UNBUNDLING)

An order issued April 8, 1992, by the FERC, requiring open-access interstate pipeline companies to unbundle their transportation delivery services from their natural gas sales services. Order 636 also required other changes designed to enhance the access to gas supplies, no matter who owned or sold them, on an equal basis.

FIELD

A single pool or multiple pools of hydrocarbons grouped on, or related to, a single structural or stratigraphic feature.

FINDING RATE

Some measure of "added proved reserves" divided by some measure of either time or the physical or investment effort expended to generate them. There are many different specific formulations in use.

FIRM GAS

Gas sold on a continuous and generally long-term contract.

FIRM SERVICE

Service offered to customers (regardless of class of service) under schedules or contracts that anticipate no interruptions. The period of service may be for only a specified part of the year as in off-peak service. Certain firm service contracts may contain clauses that permit unexpected interruption in case the supply to residential customers is threatened during an emergency.

FLARED

Natural gas burned in flares at the base site or a gas-processing plants.

FRACTURING

Improvement of the flow continuity between gas-bearing reservoir rock and the wellbore by erecting fractures which extend the distances into the reservoir.

FUEL CELLS

A fuel cell, configured like a battery, combines natural gas and oxygen in an electrochemical reaction that produces electricity, heat, and water (often in the form of steam).

GAS BUBBLE

Surplus gas deliverability at the wellhead.

GAS CONDENSATE WELL

A gas well producing from a gas reservoir containing considerable quantities of liquid hydrocarbons in the pentane and heavier range, generally described as "condensate."

GAS WELL

A gas well completed for the production of natural gas from one or more gas zones or reservoirs.

GATHERING SYSTEM

Facilities constructed and operated to receive natural gas from the wellhead and transport, process, compress, and deliver that gas to a pipeline, LDC, or end user. The construction and operation of gathering systems is not a federally regulated business, and in some states is not regulated by the state.

GENERATING UNIT

Any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

GENERATION (ELECTRICITY)

The process of producing electric energy by transforming other forms of energy; also, the amount of electric energy produced, expressed in watthours (WH).

GENERATOR

A machine that converts mechanical energy into electrical energy.

GENERATOR NAMEPLATE CAPACITY

The full-load continuous rating of a generator, prime mover, or other electric power production equipment under specific conditions as designated by the manufacturer. Installed generator nameplate rating is usually indicated on a nameplate physically attached to the generator.

GREENFIELD

A "new" site for the construction of an electric generation plant; in other words, a location that did not previously have a generation unit.

GREENHOUSE EFFECT

The increasing mean global surface temperature of the earth caused by gases in the atmosphere (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon). The greenhouse effect allows solar radiation to penetrate but absorbs the infrared radiation returning to space.

GRID-TYPE SYSTEM

This term describes a natural gas pipeline company that operates facilities which physically interconnect at numerous points within its service area. Typically such a system receives gas from a variety of sources from both ends of its system and is characterized by gas flows which are difficult to trace in a linear fashion.

GROSS WITHDRAWALS

Full well-stream volume, including all natural gas plant liquids and all nonhydrocarbons gases, but excluding lease condensate.

HEATING VALUE

The average number of British thermal units per cubic foot of natural gas as determined from tests of fuel samples.

HUB

A hub is a location where gas sellers and gas purchasers can arrange transactions. The location of the hub can be anywhere multiple supplies, pipelines, or purchasers interconnect. "Market centers" are hubs located near central market areas. "Pooling points" are hubs located near center supply production areas. Physical hubs are found at processing plants, offshore platforms, pipeline interconnects, and storage fields. "Paper" hubs may be located anywhere parties arrange title transfers (changes in ownership) of natural gas.

HYDRATES

Gas hydrates are physical combinations of gas and water in which the gas molecules fit into a crystalline structure similar to that of ice. Gas hydrates are considered a speculative source of gas.

HYDROCARBON SUPPLY MODEL

Energy and Environmental Analysis, Inc.'s model of the U.S. and Canada's potential recoverable resource base. This model seeks to show the impact of technological advancements and exploratory and development drilling activity and was used in the NPC Gas Study.

IMPORTS

Gas receipts into the United States from a foreign country.

IN-PLACE GAS RESOURCE

The total in-place gas is the summation of gas already produced, the technically recoverable resource, and the remaining in-place resource.

INCENTIVE REGULATION

An alternative to, or modification of, cost of service regulation, which is used in markets that lack sufficient competition (examples include price caps, zone of reasonableness, bounded rates, sharing of efficiency gains, and incentive rates of return).

INDEPENDENT POWER PRODUCERS (IPPs)

Wholesale electricity producers that are unaffiliated with franchised utilities in their area. IPPs do not possess transmission facilities and do not sell power in any retail service territory.

INDUSTRIAL CONSUMPTION

Natural gas consumed by manufacturing and mining establishments for heat, power, and chemical feedstock.

INDUSTRIAL CONSUMERS

Establishments engaged in a process that creates or changes raw or unfinished materials into another form or product. Generation of electricity, other than by electric utilities is included.

INTEGRATED RESOURCE PLAN (IRP)

A plan or process used by utilities to evaluate both supply-side and demand-side measures when seeking to prepare for meeting future energy needs and to do so at lowest total costs. ("Least cost" or "best cost" planning is sometimes used synonymously with integrated resource planning.)

INTERMEDIATE LOAD (ELECTRIC SYSTEM)

The range from base load to a point between base load and peak. This point may be the midpoint, a percent of the peak load, or the load over a specified time period.

INTERRUPTIBLE GAS

Gas sold to customers with a provision that permits curtailment or cessation of service at the discretion of the distributing company or pipeline under certain circumstances, as specified in the service contract.

INTERRUPTIBLE SERVICE

A sales volume or pipeline capacity made available to a customer without a guarantee for delivery. "Service on an interruptible basis" means that the capacity used to provide the service is subject to a prior claim by another customer or another class of service (18 CFR 284.9(a)(3)). Gas utilities may curtail service to their customers who have interruptible service contracts to adjust to seasonal shortfalls in supply or transmission plant capacity without incurring a liability.

INTERSTATE PIPELINE COMPANY

A company subject to regulation by the Federal Energy Regulatory Commission pursuant to the Natural Gas Act of 1938 because of its construction and/or operation of natural gas pipeline facilities in interstate commerce.

INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA (INGAA)

Trade group that represents interstate pipeline companies.

INTRASTATE PIPELINE COMPANY

A company that operates natural gas pipeline facilities which do no cross a state border.

KILOWATT

One thousand watts. (*See* Watt.)

LARGE DIAMETER PIPE

High pressure natural gas pipeline is constructed, typically, of steel, in different sizes from one inch, outside diameter (O.D.) to 42 inches. Typically "large diameter pipe" is larger than 20 inches, O.D.

LEASE AND PLANT FUEL

Natural gas used in well, field, and lease operations, (such as gas used in drilling operations, heaters, dehydrators, and field compressors), and as fuel in natural gas processing plants.

LIGHT-HANDED REGULATION

Regulation characterized by reliance on market forces where they are available to help ensure fair access and stable prices. Generally, under such a scheme, companies are given significant discretion to enter and leave a particular service, and over what rate it charges. While such activities are not "deregulated" in the normal sense of the phrase, regulatory scrutiny is usually generic and compliance oriented, rather than intrusive.

LINE PACK

The volume of natural gas contained, in a point of time, within the pipeline. Also, a technique to fill a pipeline to its maximum capacity in anticipation of high demands, or hourly fluctuations in demand.

LIQUEFIED NATURAL GAS (LNG)

Natural gas that has been reduced to a liquid stage by cooling to -260 degrees Fahrenheit and thus sustains a volume reduction of approximately 600 to 1.

LOAD (ELECTRIC)

The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

LOCAL DISTRIBUTION COMPANY (LDC)

A company that distributes natural gas at retail to individual residential, commercial, and industrial consumers. LDCs are typically granted an exclusive franchise to serve a geographic area by state or local governments, subject to some requirement to provide universal service. Rates and terms and conditions of service are typically (but not always) subject to regulation.

LOOPING

A method of expanding the capacity of an existing pipeline system by laying new pipeline adjacent to an existing pipeline and connected to the existing system at both ends.

LOW PERMEABILITY

Gas that occurs in formations with a permeability of less than 0.1 millidarcy.

MANUFACTURED GAS

A gas obtained by destructive distillation of coal, or by the thermal decomposition of oil, or by the reaction of steam passing through a bed of heated coal or coke. Examples are coal gases, coke oven gases, producer gas, blast furnace gas, blue (water) gas, carbureted water gas. BTU content varies widely.

MARKET CENTER

A place, located near natural gas market areas, where many gas sellers and gas buyers may arrange to buy/sell natural gas. See "Hub."

MARKETED PRODUCTION

Gross withdrawals less gas consumed for repressuring, quantities vented and flared, and nonhydrocarbon gases removed in treating or processing operations.

MCF/D

"Thousand cubic feet of natural gas per day." A volume unit of measurement for natural gas.

MEGAWATT

One million watts of electric capacity. (*See* Watt.)

MINIMUM BILL

A distributor's obligation to take or pay for the gas volumes specified in its firm service agreements with the pipeline.

MMBTU

"Million British Thermal Units." A unit of measurement of the heating content, as measured in BTU, of natural gas.

MMCF/D

"Million cubic feet of natural gas per day." A volume unit of measurement for natural gas.

NATIONAL ENERGY BOARD

The agency of the Canadian federal government which regulates international and inter-provincial and natural gas trade with(in) Canada. The "NEB" is the Canadian counterpart to the FERC, and like FERC also regulates electricity.

NATIVE GAS

The gas remaining in a reservoir at the end of a reservoir's producing life. After a reservoir is converted to storage, remaining gas becomes part of the cushion gas volume.

NATURAL GAS

A gaseous hydrocarbon fuel. Primarily made up of the chemical compound methane, or CH_4. Natural gas is found in underground reservoirs, often in combination with oil, and other hydrocarbon compounds.

NATURAL GAS, WET AFTER LEASE SEPARATION

The volume of natural gas remaining after removal of lease condensate in lease and/or field separation facilities, if any, and after exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Natural gas liquids may be recovered from volume of natural gas, wet after lease separation, at natural gas processing plants.

NATURAL GAS ACT OF 1938

Act passed by Congress which regulates the transportation and sale of natural gas in interstate commerce. This statute is administered by the FERC.

NATURAL GAS COUNCIL

Formed in 1992 through the four major U.S. gas industry trade groups to promote awareness of the potential of natural gas and to develop a unified gas industry.

NATURAL GAS POLICY ACT OF 1978

An act of Congress which effected the phased decontrol of certain categories of natural gas wellhead prices.

NATURAL GAS SUPPLY ASSOCIATION

Trade group that represents natural gas producers, whether integrated or small.

NATURAL GAS WELLHEAD DECONTROL ACT OF 1989

This Act fully decontrols natural gas wellhead prices effective January 1, 1993.

NETBACK PRICE

The price for natural gas the producer receives "at the wellhead" as determined by subtracting the cost of all delivery services from the price received "at the burnertip" for natural gas. In a competitive end-use market, it is presumed that a producer would receive no more than the netback price for its gas.

NEW FIELDS

A category of the resource base which represents gas that is yet to be discovered. This category is quantified based on risked assessments attributing geologic similarities from known areas, defined as those resources estimated to exist outside of known fields on the basis of broad geologic knowledge and theory.

NO-NOTICE TRANSPORTATION SERVICE

A term used in FERC Order 636 to describe firm transportation service equivalent in quality to the delivery service provided as an integral part of traditional firm pipeline natural gas sales services.

NONCONVENTIONAL GAS

Resource that includes shale gas, coalbed methane, and tight gas as these are in a relatively early stage of technical development.

NONHYDROCARBON GASES

Typical nonhydrocarbon gases that may be present in reservoir natural gas, such as carbon dioxide, helium, hydrogen sulfide, and nitrogen.

NORM

"Naturally Occurring Radioactive Material" in exploration and production operations originates in subsurface oil and gas formations and is typically transported to the surface in produced water, both onshore and offshore.

OFF-PEAK

Periods of time when natural gas pipeline facilities are typically not flowing natural gas at design capacity.

OFFSHORE RESERVES AND PRODUCTION

Unless otherwise indicated, reserves and production that are in either state or federal domains, located seaward of the coastline.

OIL-EQUIVALENT GAS

Gas volume that is expressed in terms of its energy equivalent in barrels of oil (BOE). One BOE equals 5,650 cubic feet of gas.

OPEN-ACCESS TRANSPORTATION

Interstate natural gas transportation service, available to any willing, creditworthy shipper, subject to the availability of capacity, on a non-discriminatory basis. (*See* FERC Order 436).

OPERATING CAPACITY

The maximum volume of gas an underground storage field can store. This quantity is limited by such factors as facilities, operational procedure, confinement, and geological and engineering properties.

OUTER CONTINENTAL SHELF (OCS)

The undersea area offshore from the coastline of a continent. This area may stretch for many miles from the coastline and be covered by shallow ocean. The Gulf Coast adjacent to Texas, Louisiana, Mississippi, and Alabama is an OCS area with substantial natural gas fields currently providing a significant source of natural gas supplies for the United States. The federal offshore usually starts 3 miles offshore (e.g., Louisiana), but starts 10 miles offshore of Texas.

PEAK DAY

The day of maximum demand for natural gas service. In any given area, the "peak day" usually occurs on the coldest day of the year, when demand for natural gas for heating is at its highest. Because each part of the country experiences different weather conditions, the peak day for each region or area is usually different. In some parts of the country, such as the Southeast and the Southwest Central regions, the peak day may occur on the hottest day of the year, when demand for space cooling drives electric generation demand to its highest levels.

PEAK-DAY DELIVERABILITY

The rate of delivery at which a storage facility is designed to be used for peak days.

PEAKING UNIT

An electric generation unit that is only run to serve "peak" demand. An electric generation unit is normally operated during the hours of highest daily, weekly, or seasonal load. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on a "round-the-clock" basis.

***PHILLIPS* DECISION**

In 1954, the U.S. Supreme Court in *Phillips Petroleum Company v. Wisconsin* interpreted the Natural Gas Act as requiring wellhead price of interstate gas to be regulated by the Federal Power Commission.

PIPELINE FUEL

Gas consumed in the operation of pipelines, primarily in compressors.

PIPELINE

A continuous pipe conduit, complete with such equipment as valves, compressor stations, communications systems, and meters, for transporting natural and/or supplemental gas from one point to another, usually from a point in or beyond the producing field or processing plant to another pipeline or to points of use. Also refers to a company operating such facilities.

PIPELINE MODEL

The EEA (Energy and Environmental Analysis, Inc.) model used in the NPC Gas Study, which simulates gas flow from U.S. and Canadian producing regions to consuming regions.

PLAY

A group of geologically related known accumulations and/or undiscovered accumulations or prospects generally having similar hydrocarbon sources, reservoirs, traps, and geological histories.

POOLING POINT

Production area pooling points are areas where gas merchants aggregate supplies from various sources, and where title passes from gas merchant to pipeline shipper. "Paper" pooling areas are places where aggregation of supplies occurs and where pipeline balancing and penalties are determined. (*See* FERC Order 636; Hub.)

POWER POOL

An arrangement used in many regions whereby all dispatchable electric generation is under the operational control of a dispatching center controlled by the power pool, not the individual company that owns the generating equipment.

POWERPLANT AND INDUSTRIAL FUEL USE ACT OF 1978

This Act was enacted as part of the National Energy Plan and prohibited the use of oil and gas as primary fuel in newly built power generation plants or in new industrial borders larger than 100 million BTU per hour of heat input. PIFUA also limited the use of natural gas in existing power plants based on fuel used during 1974-76, and prohibited switching from oil to gas.

PREBUILD

The "Prebuild" System was authorized in 1977 and provides natural gas from Alberta, Canada, to markets in California and the Midwest. The "prebuild" system is Phase I of the Alaska Natural Gas Transportation System.

PRODUCTION, WET AFTER LEASE SEPARATION

Gross withdrawals less gas used for repressuring and nonhydrocarbon gases removed in treating or processing operations.

PRORATION POLICY

Policies within some gas-producing states that set production limits in order to protect the correlative mineral rights of producers and royalty owners and to prevent physical waste.

PROSPECT

A geological feature having the potential for trapping and accumulating hydrocarbons.

PROVED RESERVES

The most certain of the resource base categories as they represent estimated quantities which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

RATE BASE

The value established by a regulatory authority, upon which a utility is permitted to earn a specified rate of return.

REFINERY GAS

Noncondensate gas collected in petroleum refineries.

REGULATORY LAG

Length of time between occurrence of a cost by a regulated entity and the reflection of that cost in the actual rates.

RENEWABLE ENERGY SOURCES

Sources of energy, usually for electric generation, that include hydropower, geothermal, solar, wind, and biomass.

REPRESSURING

The injection of gas into oil or gas reservoir formations to effect greater ultimate recovery.

RESERVE APPRECIATION

The portion of the conventional resource base that results from the recognition that currently booked proved reserves are conservative by definition and will continue to grow over time. This component represents the growth of ultimate recovery (cumulative production plus proved reserves) from known fields that occurs over time.

RESERVE GROWTH

Composed of new reservoirs, extensions, and net positive revisions.

RESERVE-TO-PRODUCTION RATIO

Used as an indicator that measures the relative size of ready inventory of gas supply to the current production rate.

RESERVOIR PRESSURE

The force within a reservoir that causes the gas and/or oil to flow through the geologic formation to the wells.

RESIDENTIAL CONSUMPTION

Gas consumed in private dwellings, including apartments, for heating, air conditioning, cooking, water heating, and other household uses.

RESOURCE BASE

Composed of proved reserves, conventional resources (reserve appreciation and new fields), and nonconventional resources (coalbed methane, shales, tight gas).

RESOURCE COST CURVE

A curve that portrays estimates of the wellhead gas price required to develop a certain volume of the resource base and yield a minimum rate of return to the investor.

RESOURCES

Known or postulated concentrations of naturally occurring liquid or gaseous hydrocarbons in the earth's crust which are now or which at some future time may be developed as sources of energy.

RIGHT-OF-WAY

Either a permanent or temporary (during construction) right of access to privately held land for the purpose of constructing and locating pipeline or related facilities. Although ownership remains, in many cases, with the original landowner, the pipeline purchases the right to locate a pipeline under a specific piece of property and the right of access to that land for inspection and maintenance activities. Pipeline right-of-way may be anywhere from 25 feet to 100 feet wide. Typically, at least 75 feet is desired for construction activities, while only 25 feet to 50 feet are maintained as permanent right-of-way.

RISKED (UNCONDITIONAL) ESTIMATES

Estimated quantities of the volumes of oil or natural gas that may exist in an area, including the possibility that the area is devoid of oil or natural gas are risked (unconditional) estimates. Estimates presented in this report are of this nature. For this study, the estimated conventional resource values were used in the model as certain quantities (occurrence probability of 1.0), and the sensitivity of the model results to higher and lower resource estimates was evaluated without quantifying the occurrence probabilities.

ROYALTY

The gas producer gives the mineral owner a royalty in the form of a share of the gross production of gas from the property free and clear of any production costs or sells the royalty share of gas and gives the owner the gross proceeds in cash.

SECTION 29 OF THE INTERNAL REVENUE CODE

Under this section, income tax credits are available to producers of "nonconventional" fuels, such as gas produced from geopressured brine, Devonian shale, coal seams, tight gas. To be eligible for the credit, gas from nonconventional sources must come from wells drilled before January 1, 1993, and must be produced before January 1, 2003.

SOUR GAS

Natural gas with a high content of sulfur and this requires purification before use.

SPECIAL MARKETING PROGRAMS

The FERC permitted pipelines to implement programs that allowed large industrial consumers to arrange purchases of cheaper spot market gas from producers, marketers, and pipelines, with the pipelines serving as only the transporter. These programs were ruled discriminatory by the court and ceased in 1985.

SPOT PURCHASES

A single shipment of gas fuel or volumes of gas, purchased for delivery within 1 year. Spot purchases are often made by a user to fulfill a certain portion of gas requirements, to meet unanticipated needs, or to take advantage of low prices.

STEADY STATE FLOW

A method of designing natural gas pipeline facilities to meet daily volumetric requirements. Under this method, it is assumed that the same quantity of natural gas flows during each of the 24 hours during a day.

STORAGE ADDITIONS

Volumes of gas injected or otherwise added to underground natural gas reservoirs or liquefied natural gas storage.

STORAGE FIELD

A facility where natural gas is stored for later use. A natural gas storage field is usually a depleted oil- or gas-producing field (but can also be an underground aquifer, or salt cavern). The wells on these depleted fields are used to either inject or withdraw gas from the reservoir as circumstances require.

STORAGE VOLUME

The total volume of gas in a reservoir. It is comprised of the cushion and working gas volumes.

STORAGE WITHDRAWALS

Volumes of gas withdrawn from underground storage or liquefied natural gas storage.

STRAIGHT FIXED VARIABLE (SFV)

An interstate pipeline transportation rate design that includes all of the fixed costs as part of the reservation change. Under the Modified Fixed Variable (MFV) rate design, costs are divided and some of the fixed costs are allocated back to the demand change.

SUNSHINE ACT

Act passed by Congress with the intent to prevent decisions from being made outside the protection afforded by exposure to public scrutiny.

SYNTHETIC NATURAL GAS

A manufactured product chemically similar in most respects to natural gas, resulting from the conversion or reforming of petroleum hydrocarbons or from coal gasification. It may easily be substituted for or interchanged with pipeline quality natural gas.

SYSTEM SUPPLY

Gas supplies purchased, owned, and sold by the supplier or local distribution company to the ultimate end user. System gas is subject to FERC or state tariff and is generally sold under long-term (contract) conditions.

TAKE-OR-PAY

A clause in a natural gas contract that requires that a specific minimum quantity of gas must be paid for, whether or not delivery is actually taken by the purchaser. Contracts entered into currently do not generally include a take-or-pay clause.

TECHNICALLY RECOVERABLE RESOURCE

Is composed of proved reserves and assessed resources. Assessed resources are that portion of the in-place resource which is estimated to be recoverable in the future at various assumed technology and price levels.

THERM

One hundred thousand British thermal units.

TIGHT GAS

A component of nonconventional resources which is gas found in low permeability formations (0.1 millidarcy or less).

TOP GAS

(*See* Working Gas.)

TRANSIENT FLOW

A method of designing natural gas pipeline facilities to meet the hourly fluctuations in demand.

UNBUNDLING

On April 8, 1992, the FERC issued Order 636, requiring interstate natural gas pipelines, operating under the FERC's open-access transportation program, to unbundle natural gas sales services from the transportation/delivery service. In practice, this requires affected pipelines to sell natural gas at the pipeline's physical receipt points where natural gas enters the pipeline's facilities, or at designated pooling points. The transportation service necessary to affect delivery of this gas to the customer would be provided under a separate contract. Pipelines would also be required to provide unbundled, separate, storage services. In theory, this will allow all firm customers of the pipelines to purchase natural gas from anyone, with assurance that the delivery service provided by the pipeline will be the same.

UNDERGROUND STORAGE

The storage of natural gas in underground reservoirs at a different location from which it was produced.

UNDERGROUND STORAGE INJECTIONS

Gas from extraneous sources put into underground storage reservoirs.

UNDERGROUND STORAGE WITHDRAWALS

Gas removed from underground storage reservoirs.

UNDISCOVERED CONVENTIONAL RESOURCES

Conventional resources estimated to exist, on the basis of broad geologic knowledge and theory, outside of known fields. Also included are resources from undiscovered pools within the areal confines of known fields to the extent that they occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions. For the purposes of this study, undiscovered conventional resources are a portion of the total resource base. Conventional resources are those recoverable using current recovery technology and efficiency but without reference to economic viability. These accumulations are considered to be of sufficient size and quality to be amenable to conventional recovery technology.

UNIFORM CODE

The establishment of a consistent code of regulations that is available to all jurisdictions.

UNIFORM SYSTEM OF ACCOUNTS

Prescribed financial and accounting rules and regulations established by the Federal Energy Regulatory Commission for utilities subject to its jurisdiction under the authority granted by the Federal Power Act.

VENTED

Gas released into the air on the base site or at processing plants.

VINTAGING

A method for pricing gas at the wellhead that was committed to interstate commerce prior to the passage of the Natural Gas Policy Act of 1978. Price was determined in part by the year in which the gas was dedicated to interstate commerce or the year in which drilling of the well actually commenced. Vintaging was eliminated by FERC Order 451 in November 1986.

WATT

The electrical unit of power. The rate of energy transfer equivalent to 1 ampere flowing under a pressure of 1 volt at unity power factor.

WATTHOURS

The electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electrical circuit steadily for 1 hour.

WELL WORKOVER

Work done on a well that improves the mechanical condition of the well or work that treats the reservoir in order to improve gas flow.

WORKING GAS

The volume of gas in reservoir above the designed level of the cushion gas.

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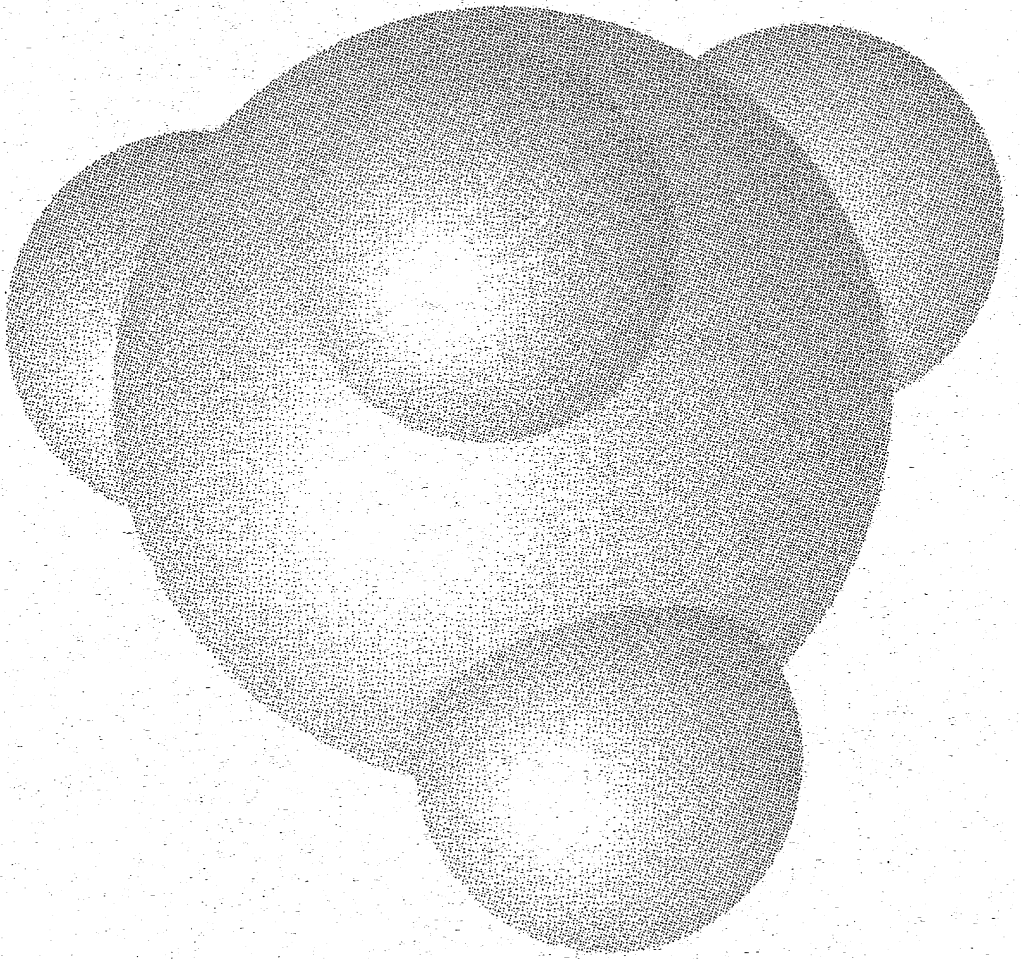

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