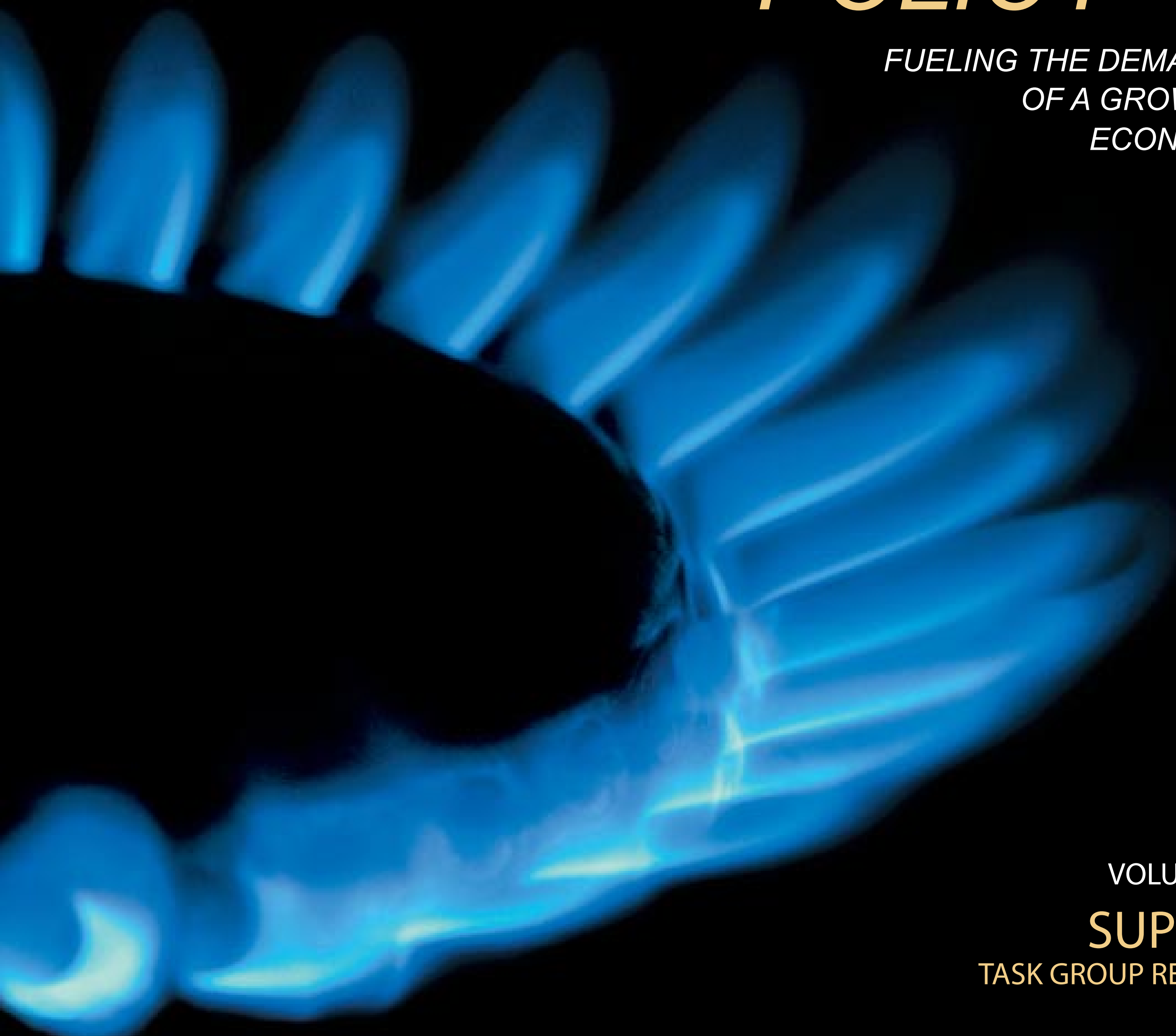
BALANCING NATURAL GAS POLICY

FUELING THE DEMANDS OF A GROWING ECONOMY



VOLUME IV

SUPPLY

TASK GROUP REPORT

NATIONAL PETROLEUM COUNCIL

SEPTEMBER 2003

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TASK GROUP REPORT

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NATIONAL PETROLEUM COUNCIL

COMMITTEE ON NATURAL GAS

BOBBY S. SHACKOULS, CHAIR

NATIONAL PETROLEUM COUNCIL

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SUPPLY TASK GROUP REPORT

PREFACE

Study Request

By letter dated March 13, 2002, Secretary of Energy Spencer Abraham requested the National Petroleum Council (NPC) to undertake a new study on natural gas in the United States in the 21st Century. Specifically, the Secretary stated:

> Such a study should examine the potential implications of new supplies, new technologies, new perceptions of risk, and other evolving market conditions that may affect the potential for natural gas demand, supplies, and delivery through 2025. It should also provide insights on energy market dynamics, including price volatility and future fuel choice, and an outlook on the longer-term sustainability of natural gas supplies. Of particular interest is the Council's advice on actions that can be taken by industry and Government to increase the productivity and efficiency of North American natural gas markets and to ensure adequate and reliable supplies of energy for consumers.

In making his request, the Secretary made reference to the 1992 and 1999 NPC natural gas studies, and noted the considerable changes in natural gas markets since 1999. These included "new concerns over national security, a changed near-term outlook for the economy, and turbulence in energy markets based on perceived risk, price volatility, fuel-switching capabilities, and the availability of other fuels." Further, the Secretary pointed to the projected growth in the nation's reliance on natural gas and noted that the future availability of gas supplies could be affected by "the availability of investment capital and infrastructure, the pace of technology progress, access to the Nation's resource base, and new sources of supplies from Alaska, Canada, liquefied natural gas imports, and unconventional resources." (Appendix A contains the complete text of the Secretary's request letter and a description of the NPC.)

Study Organization

In response to the Secretary's request, the Council established a Committee on Natural Gas to undertake a new study on this topic and to supervise the preparation of a draft report for the Council's consideration. The Council also established a Coordinating Subcommittee and three Task Groups – on Demand, Supply, and Transmission & Distribution – to assist the Committee in conducting the study.

Bobby S. Shackouls, Chairman, President and Chief Executive Officer, Burlington Resources Inc., chaired the Committee, and Robert G. Card, Under Secretary of Energy, served as the Committee's Government Cochair. Robert B. Catell, Chairman and Chief Executive Officer, KeySpan Corporation; Lee R. Raymond, Chairman and Chief Executive Officer, Exxon Mobil Corporation; and Richard D. Kinder, Chairman and Chief Executive Officer, Kinder Morgan Energy Partners, L.P., served as the Committee's Vice Chairs of Demand, Supply, and Transmission & Distribution, respectively. Jerry J. Langdon, Executive Vice President and Chief Administrative Officer, Reliant Resources, Inc., chaired the Coordinating Subcommittee, and Carl Michael Smith, Assistant Secretary, Fossil Energy, U.S. Department of Energy, served as Government Cochair.

This volume of the report was prepared by the Supply Task Group and its subgroups. Mark A. Sikkel, Vice President, ExxonMobil Production Company, chaired the Supply Task Group, and Elena S. Melchert, Program Manager, Oil and Gas Production, Fossil Energy, U.S. Department of Energy, served as Government Cochair. The Supply Task Group was assisted by five subgroups:

- Resource Subgroup
- Technology Subgroup
- Environmental/Regulatory/Access Subgroup
- LNG Subgroup
- Arctic Subgroup.

The members of the various study groups were drawn from the NPC members' organizations as well as from many other industries, non-governmental organizations, and government organizations. These study participants represented broad and diverse interests including large and small producers, transporters, service providers, financers, regulators, local distribution companies, power generators, and industrial consumers of natural gas. Appendix B contains rosters of the study's Committee, Coordinating Subcommittee, and the Supply Task Group and its subgroups. In addition to the participants listed in Appendix B, many more people were involved in the work of the study's other Task Groups and Subgroups as well as in regional and sector-specific workshops in the United States and Canada.

Study Approach

The study benefited from an unprecedented degree of support, involvement, and commitment from the gas industry. The breadth of support was based on growing concerns about the adequacy of natural gas supplies to meet the continuing strong demand for gas, particularly in view of the role of gas as an environmentally preferred fuel. The study addresses both the short-term and long-term outlooks (through 2025) for North America, defined in this study as consisting of Canada, Mexico, and the United States. The reader should recognize that this is a natural gas study, and not a comprehensive analysis of all energy sources such as oil, coal, nuclear, and renewables. However, this study does address and make assumptions regarding these competing energy sources in order to assess the factors that may influence the future of natural gas use in North America. The analytical portion of this study was conducted over a 12-month period beginning in August 2002 under the auspices of the Coordinating Subcommittee and three primary Task Groups.

The Supply Task Group developed a basin-by-basin supply picture, and analyzed potential new sources of supply such as liquefied natural gas (LNG) and Arctic gas. The Supply Task Group worked through five subgroups (Resource, Technology, Environmental/Regulatory/Access, LNG, and Arctic), with over 100 people participating. These people were drawn from major and independent producers, service companies, consultants, and government agencies. These working groups conducted 13 workshops across the United States and Canada to assess the potential resources available for exploration and development. Workshops were also held to examine the potential impact on gas production from advancing technology. Particular emphasis was placed on the commercial potential of the technical resource base and the knowledge gained from analysis of North American production performance history.

The Demand Task Group developed a comprehensive sector-by-sector demand outlook. This analysis was done by four subgroups (Power Generation, Industrial Utilization, Residential and Commercial, and Economics and Demographics). The task of each group was to try to understand the economic and environmental determinants of gas consumption and to analyze how the various sectors might respond to different gas price regimes. The Demand Task Group was composed of representatives from a broad cross-section of the power industry as well as industrial consumers from gas-intensive industries. It drew on expertise from the power industry to develop a broad understanding of the role of alternative sources for generating electric power based on renewables, nuclear, coal-fired, oil-fired, or hydroelectric generating technology. It also conducted an outreach program to draw upon the expertise of power generators and industrial consumers in both the United States and Canada.

The Transmission & Distribution Task Group analyzed existing and potential new infrastructure. Their analysis was based on the work of three subgroups (Transmission, Distribution, and Storage). Industry participants undertook an extensive review of existing and planned infrastructure capacity in North America. Their review emphasized, among other things, the need to maintain the current infrastructure and to ensure its reliability. Participants in the Transmission & Distribution Task Group included representatives from U.S. and Canadian pipeline, storage, marketing, and local distribution companies as well as from the producing community, the Federal Energy Regulatory Commission, and the Energy Information Administration.

Separately, two other groups also provided guidance on key issues that crossed the boundaries of the primary task groups. An ad hoc financial team looked at capital requirements and capital formation. Another team examined the issue of increased gas price volatility.

Due to similarities between the Canadian and U.S. economies and, especially, the highly interdependent character of trade in natural gas, the evaluation of natural gas supply and demand in Canada and the United States were completely integrated. The study included Canadian participants, and many other participating companies have operations in both the United States and Canada. For Mexico, the evaluation of natural gas supply and demand for the internal market was less detailed, mainly due to time limitations. Instead, the analysis focused on the net gas trade balances and their impact on North American markets.

As in the 1992 and 1999 studies, econometric models of North American energy markets and other analytical tools were used to support the analyses. Significant computer modeling and data support were obtained from outside contractors; and an internal NPC study modeling team was established to take direct responsibility for some of the modeling work. The Coordinating Subcommittee and its Task Groups made all decisions on model input data and assumptions, directed or implemented appropriate modifications to model architecture, and reviewed all output. Energy and Environmental Analysis, Inc. (EEA) of Arlington, Virginia, supplied the principal energy market models used in this study, and supplemental analyses were conducted with models from Altos Management of Los Altos, California.

The use of these models was designed to give quantified estimates of potential outcomes of natural gas demand, supply, price and investment over the study time horizon, with a particular emphasis on illustrating the impacts of policy choices on natural gas markets. The results produced by the models are critically dependent on many factors, including the structure and architecture of the models, the level of detail of the markets portrayed in the models, the mathematical algorithms used, and the input assumptions specified by the NPC Study Task Groups. As such, the results produced by the models and portrayed in the NPC report should not be viewed as forecasts or as precise point estimates of any future level of supply, demand, or price. Rather, they should be used as indicators of trends and ranges of likely outcomes stemming from the particular assumptions made. In particular, the model results are indicative of the likely directional impacts of pursuing particular public policy choices relative to North American natural gas markets.

This study built on the knowledge gained and processes developed in previous NPC studies, enhanced those processes, created new analytical approaches and tools, and identified opportunities for improvement in future studies. Specific improvements included the following elements developed by the Supply Task Group:

- A detailed play-based approach to assessment of the North American natural gas resource base, using regional workshops to bring together industry experts to update existing assessments. This was used in two detailed descriptive models, one based on 72 producing regions in the United States and Canada, and the other based on 230 supply points in the United States, Canada, and Mexico. Both models distinguished between conventional and nonconventional gas and between proved reserves, reserve growth, and undiscovered resource.

- Cost of supply curves, including discovery process models, were used to determine the economically optimal pace of development of North American natural gas resources.

- An extensive analysis of recent production performance history, which clearly identified basins that are maturing and those where production growth potential remains. This analysis helped condition the forward-looking assumptions used in the models.

- A model to assess the impact of permitting in areas currently subject to conditions of approval.

- A first-ever detailed NPC view and analysis of LNG and Arctic gas potential.

The Demand Task Group also achieved significant improvements over previous study methods. These improvements include the following:

- Regional power workshops and sector-specific industrial workshops to obtain direct input on consuming trends and the likely impact of changing gas prices.

- Ongoing detailed support from the power industry for technology and cost factors associated with current and future electric power generation.

- Development of a model of industrial demand focusing on the most gas-intensive industries and processes.

Study Report

Results of this 2003 NPC study are presented in a multi-volume report as follows:

- Volume I, *Summary of Findings and Recommendations*, provides insights on energy market dynamics as well as advice on actions that can be taken by industry and government to ensure adequate and reliable supplies of energy for American consumers. It includes an Executive Summary of the report and an overview of the study's analyses and recommendations.

- Volume II, *Integrated Report*, contains discussions of the results of the analyses conducted by the three Task Groups: Demand, Supply, and Transmission & Distribution. This volume provides further supporting data and analyses for the findings and recommendations presented in Volume I. It addresses the potential implications of new supplies, new technologies, new perceptions of risk, and other evolving market conditions that may affect the potential for natural gas demand, supplies, and delivery through 2025. It provides insights on energy market dynamics, including price volatility and future fuel choice, and an outlook on the longer-term sustainability of natural gas supplies. It also expands on the study's recommended policy actions. This volume presents an integrated outlook for natural gas demand, supply, and transmission in the United States, Canada, and Mexico under two primary scenarios and a number of sensitivity cases.

  The demand analysis provides an understanding of the economic and environmental determinants of natural gas consumption to estimate how the industrial, residential/commercial, and electric power sectors may respond under different conditions. The supply analysis develops basin-by-basin resource and cost estimates, presents an analysis of recent production performance, examines potential technology improvements, addresses resource access issues, and examines potential supplies from traditional areas as well as potential new sources of supply such as liquefied natural gas and Arctic gas. The transmission, distribution, and storage analysis provides an extensive review of existing and planned infrastructure in North America emphasizing, among other things, the need to maintain the current infrastructure and to ensure its reliability.

- *Task Group Report Volumes and CD-ROMs* include the detailed data and analyses prepared by the Demand, Supply, and Transmission & Distribution Task Groups and their Subgroups, which formed the basis for the development of Volumes I and II. Information on the study's computer modeling activities is also included. The Council believes that these materials will be of interest to the readers of the report and will help them better understand the results. The members of the National Petroleum Council were not asked to endorse or approve all of the statements and conclusions contained in these documents but, rather, to approve the publication of these materials as part of the study process. These documents are provided as follows:

  – Volume III, *Demand Task Group Report*, provides in-depth discussions and analyses of economic and demographic assumptions; consumption in the industrial, residential, commercial, and electric power sectors; and uncertainties/sensitivities.

  – Volume IV, *Supply Task Group Report*, provides in-depth discussions and analyses of resource assessment, cost methodology, production performance, technology improvements, access issues, and arctic developments.

  – Volume V, *Transmission & Distribution Task Group and LNG Subgroup Reports*, provides in-depth discussions and analyses of LNG imports and transmission, distribution, and storage infrastructures. (While the LNG Subgroup operated under the Supply Task Group, its report is provided with that of the Transmission & Distribution Task Group due to the interrelationship of their infrastructures and issues.)

– *CD-ROMs* are available as part of the documentation of the Task Group Reports. One CD contains further input/output on a regional basis for the study's principal modeling activities. That CD also contains digitized maps, which were used in assessing the potential impact of conditions of approval for access to key Rocky Mountain resource areas. Another CD contains the input data developed by the NPC for use in the study's supplemental modeling activities.

A form for ordering additional copies of the report volumes can be downloaded from the NPC website, http://www.npc.org. PDF versions of Volumes I through V also can be viewed and downloaded from the NPC website.

Retrospectives on 1999 Study

In requesting the current study, the Secretary noted that natural gas markets had changed substantially since the Council's 1999 study. These changes were the reasons why the 2003 study needed to be a comprehensive analysis of natural gas supply, demand, and infrastructure issues. By way of background, the 1999 study was designed to test the capability of the supply and delivery systems to meet the then-public forecasts of an annual U.S. market demand of 30+ trillion cubic feet early in this century. The approach taken in 1999 was to review the resource base estimates of the 1992 study and make any needed modifications based on performance since the publication of that study. This assessment of the natural gas industry's ability to convert the nation's resource base into available supply also included the first major analytical attempt to quantify the effects of access restrictions in the United States, and specifically the Rocky Mountain area. Numerous government agencies used this work as a starting point to attempt to inventory various restrictions to development. This access work has been further expanded upon in the current study. Further discussions of the 1999 analyses are contained in the Task Group reports.

The 1999 report stated that growing future demands could be met if government would address several critical factors. The report envisioned an impending tension between supply and demand that has since become reality in spite of lower economic growth over the intervening time period. On the demand side, government policy at all levels continues to encourage use of natural gas. In particular, this has led to large increases in natural gas-fired power generation capacity. The 1999 study assumed 144 gigawatts of new capacity through 2015, while the actual new capacity is expected to exceed 200 gigawatts by 2005. On the supply side, limits on access to resources and other restrictive policies continue to discourage the development of natural gas supplies. Examples of this are the 75% reduction in the Minerals Management Service's Eastern Gulf Lease Sale 181 and the federal government's "buying back" of the Destin Dome leases off the coast of Florida.

The maturity of the resource base in the traditional supply basins in North America is another significant consideration. In the four years leading up to the publication of this study, North America has experienced two periods of sustained high natural gas prices. Although the gas-directed rig count did increase significantly between 1999 and 2001, the result was only minor increases in production. Even more sobering is the fact that the late 1990s was a time when weather conditions were milder than normal, masking the growing tension between supply and demand.

In looking forward, the Council believes that the findings and recommendations of this study are amply supported by the analyses conducted by the study groups. Further, the Council wishes to emphasize the significant challenges facing natural gas markets and to stress the need for all market participants (consumers, industry, and government) to work cooperatively to develop the natural gas resources, infrastructure, energy efficiency, and demand flexibility necessary to sustain the nation's economic growth and meet environmental goals.

CHAPTER 1

INTRODUCTION

The Supply Task Group Report provides detailed documentation of the methodologies employed by the Supply Task Group to develop an outlook for natural gas supplies and the corresponding results of this outlook. This volume is organized with chapters for each of the subgroups that operated under the Supply Task Group as follows:

Chapter 2 – Resource Assessment

Chapter 3 – Cost Methodology

Chapter 4 – Production Performance

Chapter 5 – Technology Improvements

Chapter 6 – Access Issues

Chapter 7 – Arctic Developments.

The LNG Subgroup also reported to the Supply Task Group, but its report is contained in Volume V along with the report of the Transmission & Distribution Task Group.

In addition to the data contained in this report, a CD-ROM is available that contains Excel spreadsheets of the modeling output for all the cases developed by the study team. Supply information for these cases includes; annual production, reserves, and drilling activities by producing regions; LNG import volumes by location; cost of supply data by region; and technical resource by technology by region. Also included on the CD-ROM are digitized maps of the Rocky Mountain producing basins and the habitat assessments that were conducted to evaluate the impact of conditions of approval on resource access.

Below is a summary of the study approach taken by the Task Group and each of the subgroups conducting the study.

In undertaking its analysis of natural gas supply, the Supply Task Group considered the most important factors affecting the current supply situation and the long-range outlook. This analysis included the following:

- A comprehensive review of the North American gas resource base using the best publicly available data. This assessment included a thorough review of both conventional and nonconventional resources (including tight gas, coal bed gas, and shale gas). In order to gain a solid understanding of potentially commercial recoverable resources, the review also included a detailed assessment of drilling and development costs, and the likely number and size of future discoveries.

- A comprehensive review of the production performance history for the mature basins of North America. This was needed in order to gain an understanding of the future production decline rates of existing reserves, the likely response to future drilling, and the potential for growth in proved reserves from revisions and extensions to existing fields.

- An evaluation of the effect of the permitting process and access restrictions on development of indigenous resources.

- An assessment of the effect that technology advances might have on the cost and availability of gas resources.

- An assessment of the potential contribution from major new supply sources, such as imported liquefied natural gas (LNG) and Arctic gas.

The Supply Task Group had five subgroups. The Resource Subgroup was led by ExxonMobil, Technology by ChevronTexaco, Environmental/Regulatory/Access by Burlington Resources, LNG by Shell, and the Arctic Subgroup was led jointly by ExxonMobil, ConocoPhillips, and BP. Given the breadth of the resource work, the Resource Subgroup was further subdivided into conventional and nonconventional resource groups; the latter was led by Anadarko. The members of the Supply Task Group oversaw the efforts of all of the subgroups.

Based on advice of participants from prior NPC studies, high priority was given to timely completion of the resource and cost estimating work. The Resource Subgroup set out to complete the resource review before the end of 2002. They also concluded that the most efficient way to access industry experts in key North American geologic plays was to hold a series of workshops across the country, inviting the contribution of as broad a group as possible. Industry workshops were held in New Orleans, Denver, Menlo Park, Houston, Calgary, and Reston. In some cases, follow-up workshops were held to reconfirm or modify assessments in light of subsequent model projections of resource development.

The Resource Subgroup further decided that publicly available data from the U.S. Geological Survey, the Minerals Management Service, and the Canadian Gas Potential Committee were the best starting points for an industry review of the resource base. Cooperation by each of these organizations was outstanding. In these workshops, each agency was asked to describe for the group their detailed, play-by-play, resource assessment. This discussion then generated debate and comment from industry experts. In the course of this discussion, consensus emerged regarding any significant modifications that the group felt appropriate for the NPC study. The intent of this work was not to judge an assessment as "right" or "wrong," but rather to develop a "best estimate" that industry could support for modeling purposes. At the same time, key cost drivers, access issues, and technology factors were discussed. All of this information was carefully documented for future use by the appropriate subgroups, with detailed descriptions of the regional results contained in Chapters 2 and 3.

The assessment of technically recoverable resource and cost was an important part of the study, but just as important was the assessment of future production performance based upon an analysis of production history. For each significant producing basin in the United States and Canada, this analysis included the initial production rates, decline rates, and expected reserve recoveries from all gas wells drilled in the past ten years. This information was essential for assessing the production trends of proved reserves and the likely effect of future drilling on the production outlook.

One reason for this interest in production performance was the much-questioned supply response to significantly increased drilling for gas in 2000-2001. These data were used to reconcile the supply response to the drilling activity undertaken. Results of this work are described in detail in Chapter 4.

The effects of technology on future supply development can be significant. The Technology Subgroup chose a workshop process similar to the Resource Subgroup to assess how new technology might help reduce costs and increase recoveries. Many areas of technology were evaluated, including subsurface imaging, drilling and development costs, completions, coal bed gas, deepwater developments, and natural gas hydrates. The projected effects of technology on future gas recovery are significant and described in Chapter 5.

Similarly, the ability to access resources is also a critical factor in determining the future contribution of indigenous resources. The Environmental/Regulatory/Access Subgroup determined early on that their evaluation of this issue needed to go beyond "stipulations" contained in oil and gas leases, to the "conditions of approval" that accompany the development of those leases. A team of experts developed a model of how those conditions impact gas drilling and development. Those results are described in Chapter 6.

Finally, it was clear that a good assessment of the potential contributions to supply of new, large, long lead-time resources was needed. The LNG and Arctic Subgroups undertook this task. Their work included a comprehensive review of worldwide gas resource availability, an examination of resource development and liquefaction capability together with an assessment of shipping requirements, and regasification needs. Similarly, the potential for major new pipelines to bring Arctic gas to North American markets was reviewed and assessed. These analyses represent the first comprehensive work by the NPC on these new sources. The Arctic Subgroup work is documented in Chapter 7, while the LNG Subgroup Report is contained in Volume V along with the Transmission & Distribution Task Group Report.

In the following chapters, the full reports of the Supply Task Group subgroups are presented. Additional details of the study results are also available on the study CD-ROM. On overall summary of the supply outlook can be found in Chapter 4 of Volume II, Integrated Report.

CHAPTER 2

RESOURCE ASSESSMENT

I. Resource Assessment Overview

This section describes the assessment of natural gas resources in North America. The assessment of technical resource, together with cost and production performance data were used as inputs by an economic model to determine the size of the commercial resource base and to derive an outlook for natural gas production through 2025. Parts of this section have been included in the supply section of the Integrated Report, but are included again in the Task Group Report to provide continuity.

Following this overview, Section II compares and contrasts the 17 super-regions comprising North America. Section III contains detailed descriptions of the major assessment regions that aggregate into each of the super-regions. Section IV describes the methodologies used in technical resource assessment. Finally, Section V includes summary charts of technical resources by country, super-region, and region. Additional resource assessment data can be found in the CD-ROM that the NPC is making available as part of the study documentation.

A. The Assessment Process

The resource assessment was based on best practices learned from prior NPC studies and from other similar studies. It was designed to utilize publicly available data, to be play-based, and to provide a thorough review by geoscientists and engineers. The resulting assessment represents an industry consensus.

Many sources of public and commercial data were used. For the United States, data from the Minerals Management Service (MMS) and United States Geological Survey (USGS) comprised the baseline data. For Canada, the Canadian Gas Potential Committee (CGPC) assessment was primarily used. For Mexico, a combination of IHS Energy Group (IHS) and USGS data was used. Production performance data and field sizes were derived from EIA, IHS, and NRG Associates (Nehring). Cost data were derived from the American Petroleum Institute (API) in the United States and the Petroleum Services Association of Canada (PSAC) in Canada.

Early on, best practice teams were organized to formulate methodologies for reserve growth, new field (undiscovered) assessment, cost, etc. Following that, major workshops were held for the purpose of reaching industry consensus on the various assessment parameters for significant plays and basins. Subsequently, a further series of workshops was held to re-validate, or change, assessment parameters in response to information learned from the models used to develop long-term forecasts.

B. Definitions

In most cases, natural gas is a mixture of hydrocarbons (primarily methane) plus small amounts of noncombustible gases. Natural gas may be produced in association with oil, or it may come from nonassociated gas fields. Approximately 87% of North American gas production is nonassociated.

All volumes referenced in this study are dry gas remaining after liquefiable portions and non-hydrocarbon gases have been removed as required by marketing considerations.

Technical resource is defined as that quantity of gas recoverable with current technology without regard to the economics of doing so. Economic, or commercial, resource estimates are derived from economic models.

In this study, remaining technical resources include proved reserves, growth, and undiscovered, or yet-to-be-found, resources.

Proved reserves are defined as those reserves that have a high confidence of being produced, and by implication, they are already economic.

The estimated volume of gas that a field will ultimately produce is known as the estimated ultimate recovery (EUR). In this study, the EUR is equal to the sum of those volumes that have been produced (cumulative production) plus the remaining proved reserves. Statistically, it can be shown that with the passage of time successive field EUR estimates tend to grow due to improved knowledge gained through operational experience during the life of the field. Growth is the estimated technical resource remaining in a field above the current estimate of proved reserves.

Undiscovered resource is the total volume of natural gas expected to be found in the future that is not due to growth of existing fields. It assumes current technology and is not necessarily economic. Undiscovered resource is sometimes termed new field or yet-to-find.

Technology advancement will tend to increase the size of undiscovered resource depending upon the model-based timing of exploration and development. The assessments reported in this section are based upon current technology and are independent of modeling assumptions.

Undiscovered resource assessment is handled differently by each of the organizations providing the basis for this study. The theory behind each methodology is more fully described in Section IV. In general, the three main data sources (USGS, MMS, and CGPC) use statistical approaches whereby the total quantity of technical resource is described by a probability distribution of field (or pool) sizes. Discovered fields (or pools) are used to anchor the distributions so that the remaining undiscovered fields (or pools) may be quantified and aggregated to yield the undiscovered resource.

Figure S2-1 shows the relative contributions of technical resource in North America. Of the 1969 TCF North America technical resource, 69% is undiscovered. The remaining 31% is associated with known fields in the proved and growth categories. In general, the uncertainty in the undiscovered category is larger than in the growth category, and the uncertainty in "growth" is larger than in the proved category.

The undiscovered resource is split into two categories: conventional and nonconventional. Although the distinction is not absolute, conventional resources are located in discrete accumulations. They tend to have better production performance characteristics and they are amenable to traditional exploratory techniques. Nonconventional resources, including coal bed methane, shale gas and basin-centered gas, are typically continuous accumulations that are much larger in area than conventional discrete accumulations. They also tend to have poorer production performance. Prior to drilling, traditional exploratory techniques are relatively inaccurate at predicting productivity in a nonconventional accumulation.

Figure S2-2 shows the relative contribution of conventional and nonconventional undiscovered resource.

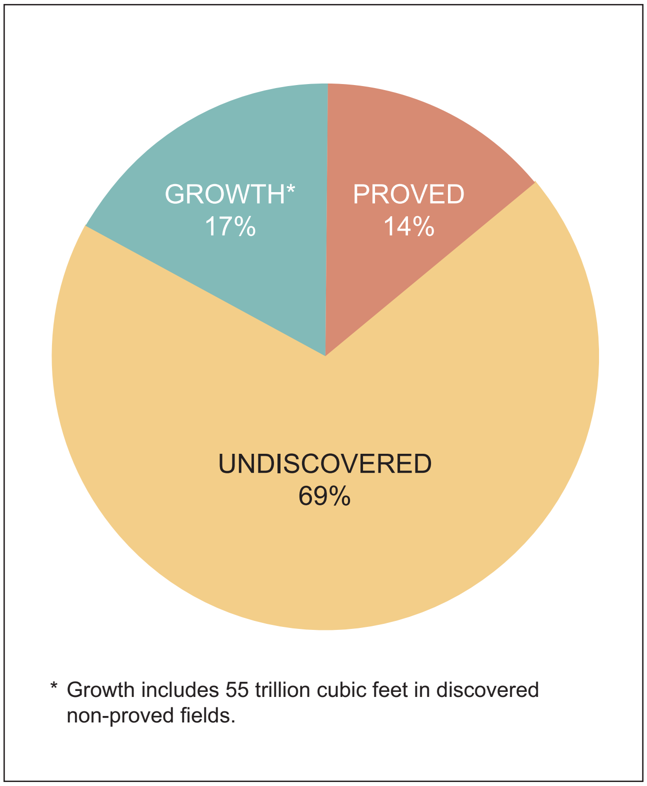


Figure S2-1. North American Technical Resource

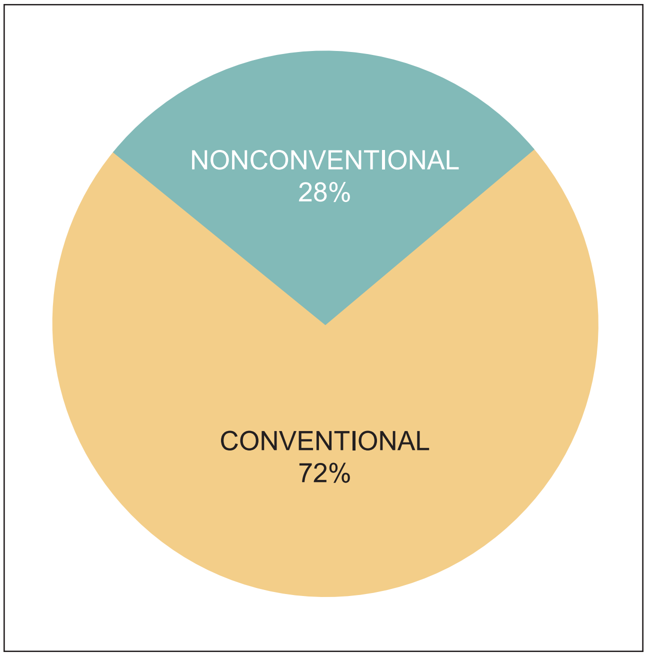


Figure S2-2. North American Undiscovered Resource

C. Assessment Granularity

The smallest unit used for assessment is the play (Assessment Unit in updated USGS terminology). A play has a coherent set of petroleum geology characteristics. North America comprises over 700 plays. For the purposes of the current NPC study and supply modeling, these plays have been aggregated into 72 regions. In their turn, the regions have been aggregated into 17 super-regions as shown in Figure S2-3.

Although comprised of many different plays, each super-region displays its own set of distinguishing features. For instance, the Rocky Mountain super-region contains predominantly nonconventional gas resource and has far more access restrictions than any other U.S. lower-48 onshore area. Each super-region is described in Section III.

D. Uncertainty Analysis

The undiscovered resource estimates for North America and its larger subdivisions (e.g. U.S. lower-48, or any of the super-regions) are aggregated from play assessments. Nearly all of these play assessments are described by probability distributions. The undiscovered resource is defined as the statistical mean of each distribution.

In order to define a range of uncertainty around the mean, this study has chosen to use a P10 value as the high-side and a P90 value as the low-side. There is a 10% chance of the high-side value, or larger, actually occurring. Similarly there is a 90% chance of the low-side value, or larger, occurring.

Although it is statistically correct to sum the individual mean resource of many plays into a super-region's resource for example, it is not valid to simply sum the P10 or P90 values. For example, it is almost impossible that the high-sides in all 700 plays will occur.

To arrive at the correct resource distribution for an aggregation of plays, the Monte Carlo method is generally used. After several statistical tests, it was decided to use a high-side of 135% of the mean and a low-side of 70% of the mean for the complete North American aggregation. Although some simplifying assumptions were made in defining this uncertainty range, industry consensus agreed that it was reasonable.

E. Technical Resources of the United States, Canada, and Mexico

The proportion of North America's proved, growth, and undiscovered technical resources in each country is shown in Figure S2-4. The United States has 1451 TCF of technical gas resource, Canada has 397 TCF, and Mexico has 121 TCF. In each country, undiscovered is the largest category of technical resource, ranging from 58% in Mexico to 70% in the United States. The remaining resource is split approximately equally between proved and growth in all three countries.

Figure S2-5 shows the volume of technical resource in TCF for each of the 17 super-regions. The top three super-regions in terms of volume are the Gulf of Mexico (323 TCF), followed by Alaska with 303 TCF and the Rockies with 284 TCF. Although these three super-regions each contain a large technical resource base, they are quite distinct in character. In the Gulf of Mexico, a growing proportion of new production will come from costlier, deeper water developments. In the Rockies, a growing proportion of new production will come from costlier nonconventional resources. On the other hand, in Alaska most of the resource is stranded due to the hostile Arctic environment and lack of a commercially viable export pipeline.

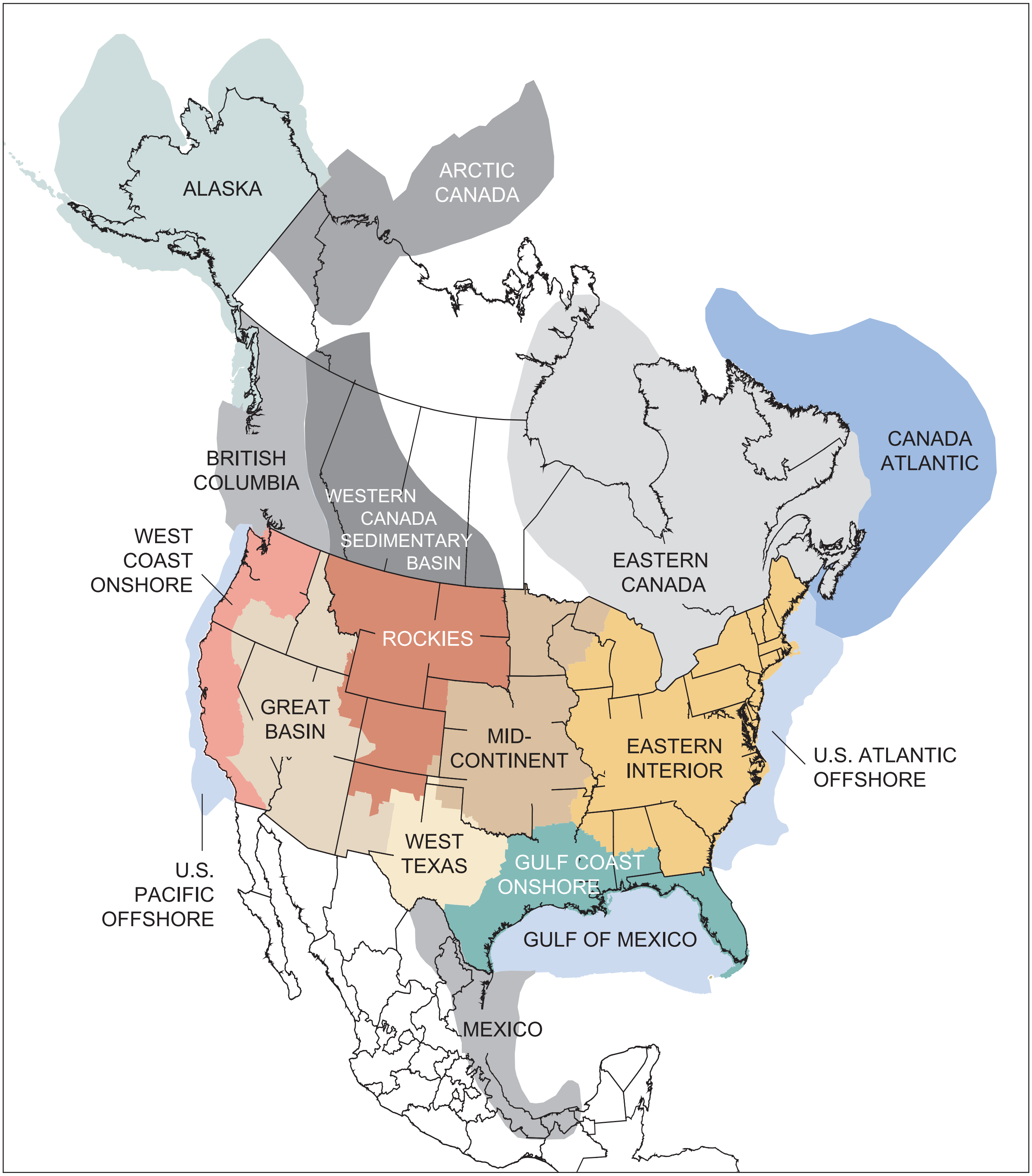


Figure S2-3. The 17 Super-Regions

A short description of the characteristics of each of the significant super-regions in the United States, Canada, and Mexico follows.

1. United States

The United States comprises 11 super-regions. Current annual lower-48 production of around 19 TCF

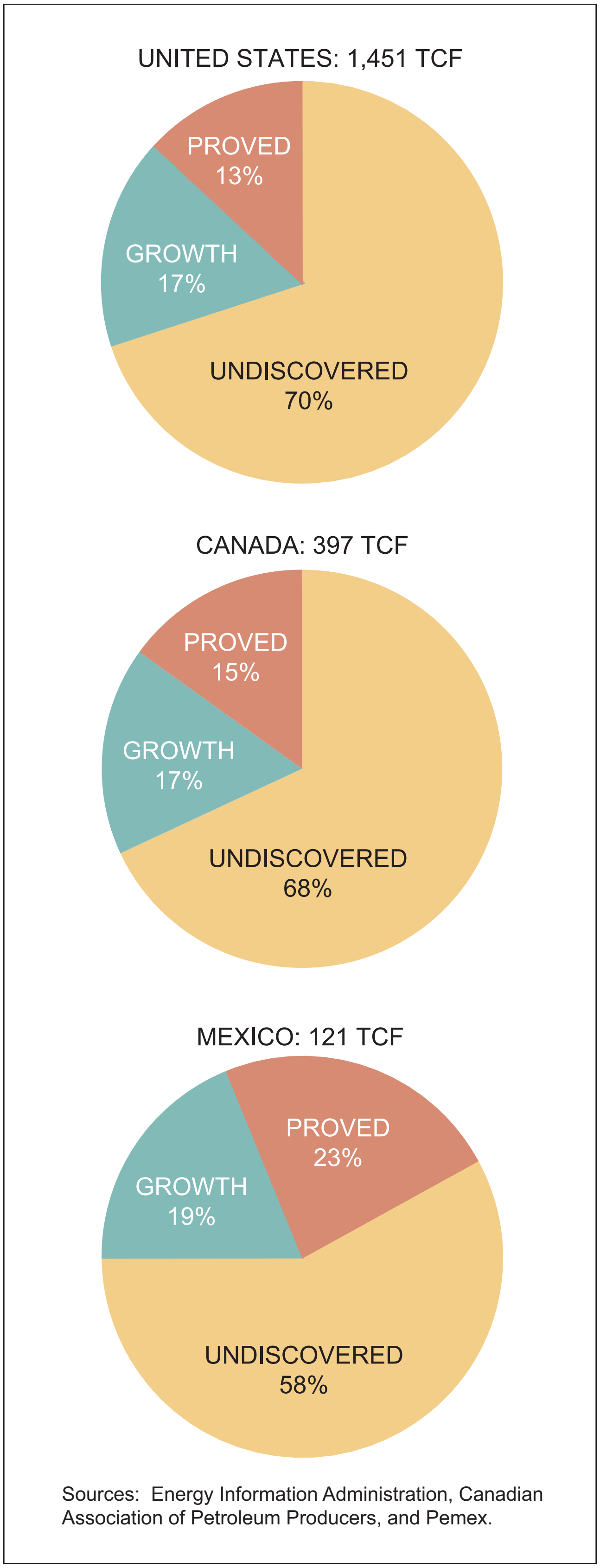


Figure S2-4. Technical Resources of United States, Canada, and Mexico

satisfies 85% of U.S. demand. In 2025, lower-48 production is projected to satisfy about 70% of U.S. demand.

Three of the super-regions provide just over 70% of current U.S. gas production: the Gulf of Mexico, 27%; the Gulf Coast Onshore, 25%; and the Rockies, 18%. In terms of technical resource, the same three super-regions contain 63% of the remaining 1451 TCF. Thus the relative production contribution from the U.S. super-regions will change through the study period.

a. Alaska

Alaska contains a very large undiscovered resource (258 TCF), located both onshore and offshore. North Alaska has a large discovered gas resource (40 TCF) which is currently stranded due to lack of pipeline. Development depends on the commercial viability of constructing a pipeline to markets in Canada and the U.S. lower-48 (Chapter 8). The remoteness and harsh environment add significantly to exploration and development cost. In addition, access to resource in the ANWR and NPRA (Section III.A) is still a contentious issue. The potentially large nonconventional undiscovered resource has a large assessment uncertainty mainly because there is a lack of data.

b. U.S. Pacific Offshore

This area has moderate undiscovered resource potential (22 TCF), but it is under a moratorium for new leases. Some wells were drilled offshore in northern California and Oregon in the 1960s with minor gas shows but without commercial success. Southern California has minor gas production associated with oil.

c. West Coast Onshore

Approximately half the total undiscovered resource of 23 TCF is nonconventional. This occurs in the north and is unlikely to be commercial during the study period because of poor reservoir quality and a thick volcanic overburden.

d. Great Basin

This large area has an extremely small potential (3 TCF) owing to a combination of geological factors. Most of this is concentrated in a small area in the east (Paradox Basin). Recent exploration results in other areas of the Great Basin have been disappointing.

e. Rockies

The total undiscovered potential here is very large (209 TCF) and is 80% nonconventional. There are

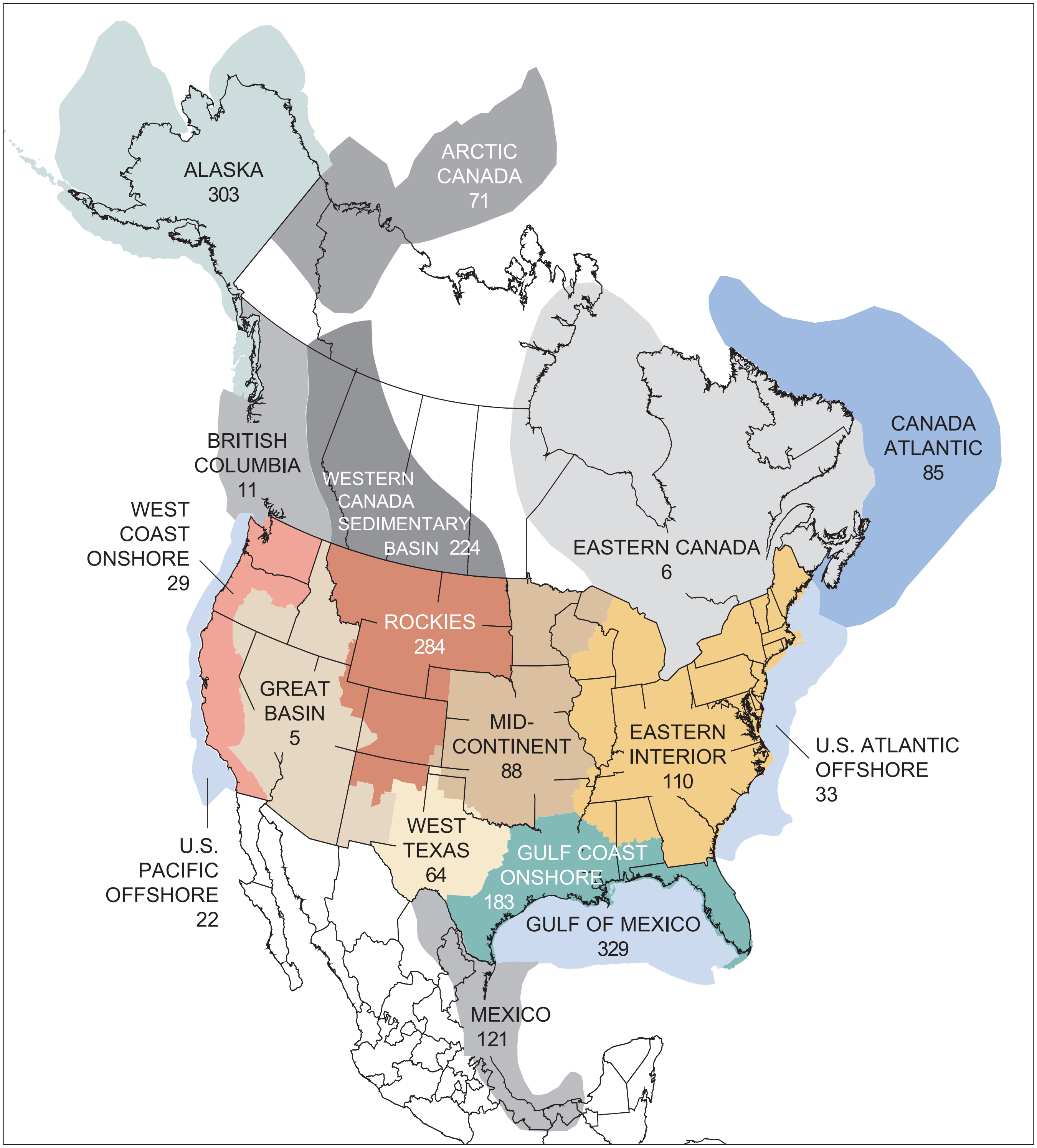


Figure S2-5. Super-Region Technical Resources (Trillion Cubic Feet)

significant access issues (Chapter 6) and, until 2002, there was insufficient pipeline export capacity. Nevertheless, production has grown and the Rockies super-region is one of the few areas where indigenous production is likely to continue growing. Discovery of the world class San Juan coal bed methane play in the 1980s led to significant, although less prolific, coal bed methane plays in other parts of the Rockies. Water discharge and operational footprint issues are likely to be future concerns. Advances in well completion technology have improved the viability of nonconventional tight gas and shale gas plays. Access and technology will determine how much of the technical resource base becomes commercial.

f. West Texas/New Mexico

Total undiscovered potential is moderate (27 TCF), because the main producing areas, such as the Permian Basin, are mature. However, downspacing and infill drilling provide some opportunities for field growth. The super-region also contains the large nonconventional Barnett Shale play in the Fort Worth basin where the recent production ramp-up has been driven by improvements in completion and stimulation technology.

g. Midcontinent

Although it is an important area of current production, this super-region contains only moderate undiscovered resource (32 TCF), mostly (85%) conventional. The Anadarko Basin has potential for further deep conventional discoveries, and other basins have small nonconventional potential.

h. Gulf Coast

The Gulf Coast is an important area of current production with a large undiscovered potential (86 TCF), over 90% conventional. Although reasonably well explored, the complex geology allows for the possibility of new trends, particularly deeper. Using improved completion and "sweet spot" detection technology, there is also the possibility of finding additional moderately large nonconventional tight and coal bed methane resources.

i. Gulf of Mexico

This is the most prolific producing super-region, even though the mature, shelf plays in shallower water are in rapid decline. Total undiscovered resource (244 TCF) is mainly in the deeper water plays where the complex geology due to salt causes higher exploration risk. Risk and deep drilling make this the highest cost area for exploration and development in the U.S. lower-48. The eastern Gulf of Mexico contains moderate undiscovered potential, but access to that region is restricted (Chapter 6).

j. U.S. Atlantic Offshore

Although this area has moderate undiscovered resource (33 TCF), it is under a leasing moratorium. There was exploration activity in the 1970s with no commercial discoveries, however the deeper water has not been tested. There was a gas discovery offshore New Jersey, but at the time it was not economic to develop. Recent adjacent Canadian discoveries suggest potential in the north of this super-region.

k. Eastern Interior

This area contains a very large, mainly nonconventional, undiscovered resource (92 TCF). Almost three-quarters of this potential is located in the Appalachian Region. However, production has barely grown over several decades. The main issues are low recoveries per well and the disparate mineral ownership. Technology improvement and a sustained higher price environment are projected to result in moderate production growth in the Eastern Interior.

2. Canada

Canada comprises five super-regions. The current annual production of 6 TCF more than satisfies internal demand. The surplus of about 3 TCF is exported to the United States. The Western Canada Sedimentary Basin contributes 97% of current production, but only 56% of Canada's 398 TCF of technical resource. As in the United States, the relative production contribution of Canada's five super-regions will change through time.

a. Western Canada Sedimentary Basin (WCSB)

The WCSB is mature and its production has plateaued. The remaining undiscovered conventional resource (93 TCF) is located in increasingly smaller average pool sizes. Nonconventional resources are not as well assessed as in the United States and have a large uncertainty range. Coal bed methane development is immature compared with the Rockies. Unlike the Rockies, access is a relatively minor issue.

b. Arctic Canada

A fairly large volume of stranded resources (25 TCF) has been discovered onshore and offshore, although much is remote. Approximately 30% of the stranded gas will be developed as part of the Mackenzie Gas Project (Chapter 7). Undiscovered resource is 46 TCF. However, much of this will not be developed through 2025 because of remoteness and Arctic conditions.

c. Canada Atlantic

Like the Canadian Arctic, stranded resources (15 TCF) have been discovered, particularly off Labrador. The undiscovered resource is also large (68 TCF). High cost and lack of pipelines will limit development of much of this resource through 2025.

d. British Columbia (Onshore and Offshore)

Excluding that part of BC assessed in the WCSB, there is moderate undiscovered potential (11 TCF) in the inter-montane and the offshore/coastal basins. Offshore access is restricted, although there is potential that restrictions will be lifted.

e. Eastern Canada

This very large area has only small undiscovered conventional and nonconventional resource (6 TCF). There is some coal bed methane activity in Nova Scotia.

3. Mexico

For the purposes of this study, Mexico has been defined as a single super-region. Current annual gas production is 1.8 TCF. The annual shortfall of 8% of demand is provided by exports from the United States. Mexico has started an ambitious program to increase its exploration and development of gas resources.

Mexico has a moderate technical resource (121 TCF), which is mainly non-associated in the north and associated with the prolific oil production in the south. Compared to adjacent U.S. areas, Mexico has been more lightly explored, particularly offshore.

F. Main Findings

1. Comparison with Assessment Baseline

The NPC's technical resource assessment is somewhat lower than the assessment baseline (USGS, MMS, CGPC, IHS). This is particularly so in the Rockies, Gulf Coast onshore, and Eastern Interior super-regions and is due to a combination of factors such as lower well recoveries in several nonconventional plays and smaller future field size assumptions for several conventional plays.

2. Comparison with the 1999 NPC Study

The 2003 study has a lower technical resource assessment than the 1999 study. The main variances occur in the Gulf of Mexico, Rockies, and Canadian Arctic super-regions. In addition, the commercial resource base is lower, even at significantly higher prices than the 1999 study. This is due to a combination of factors including the lower technical resource base, poorer production performance parameters, higher costs associated with deeper drilling and an increase in the estimation of access restricted areas.

3. Level of Confidence in the Overall Assessment

Analysis of statistical uncertainty indicates that the overall technical resource assessment could range between 35% higher and 30% lower than forecast within a high degree of confidence. This range pertains to the North American total and cannot be used as the range for sub-units such as super-region, region, or basin.

4. Quality of the Resource

As measured by averages of field size, recovery per well, and economic return, North American resource quality is declining. Traditional large producing regions such as the Gulf of Mexico Shelf and the Western Canada Sedimentary Basin, are largely depleted of high quality resource, except in a few niche areas.

Production declines from these regions will be somewhat offset by production growth in nonconventional resource regions. This will become most apparent in the Rocky Mountain basins. However, nonconventional resources generally yield lower well recoveries than have been seen in the past with conventional resources.

II. Super-Regions Compared

This section compares and contrasts the 17 super-regions in terms of their resource characteristics that determine the natural gas production outlook through 2025. Details of individual super-regions are provided in Section III.

A. The 2003 NPC, 1999 NPC, and EIA Maps

Most of the data used in this study are associated with geographic areas, or regions. The 2003 NPC study, the1999 NPC study, and the EIA each use different geographic divisions as described in the following maps.

Figure S2-6 indicates the locations of the 17 North America super-regions used in the current study. As described in Section IV, the super-regions are each

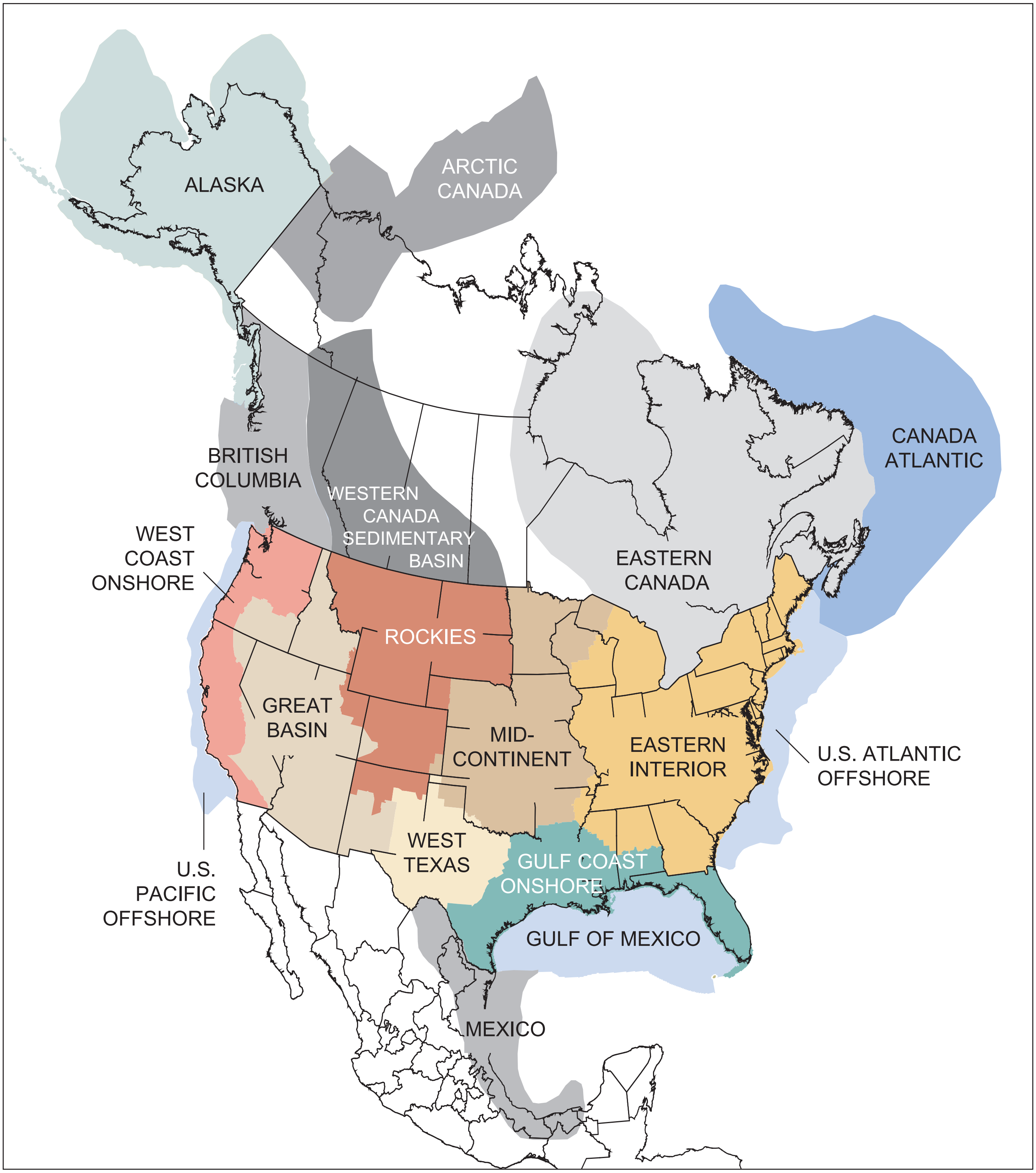


Figure S2-6. The 17 Super-Regions

comprised of a number of regions. These 72 regions are shown in Figure S2-7. For the onshore U.S. lower-48, the regions generally correspond to USGS province boundaries.

Although similar in some respects to Figure S2-6, the 26 regions used in the 1999 NPC study were more aligned with areas of production reporting. A different approach was used in the current study, whereby all

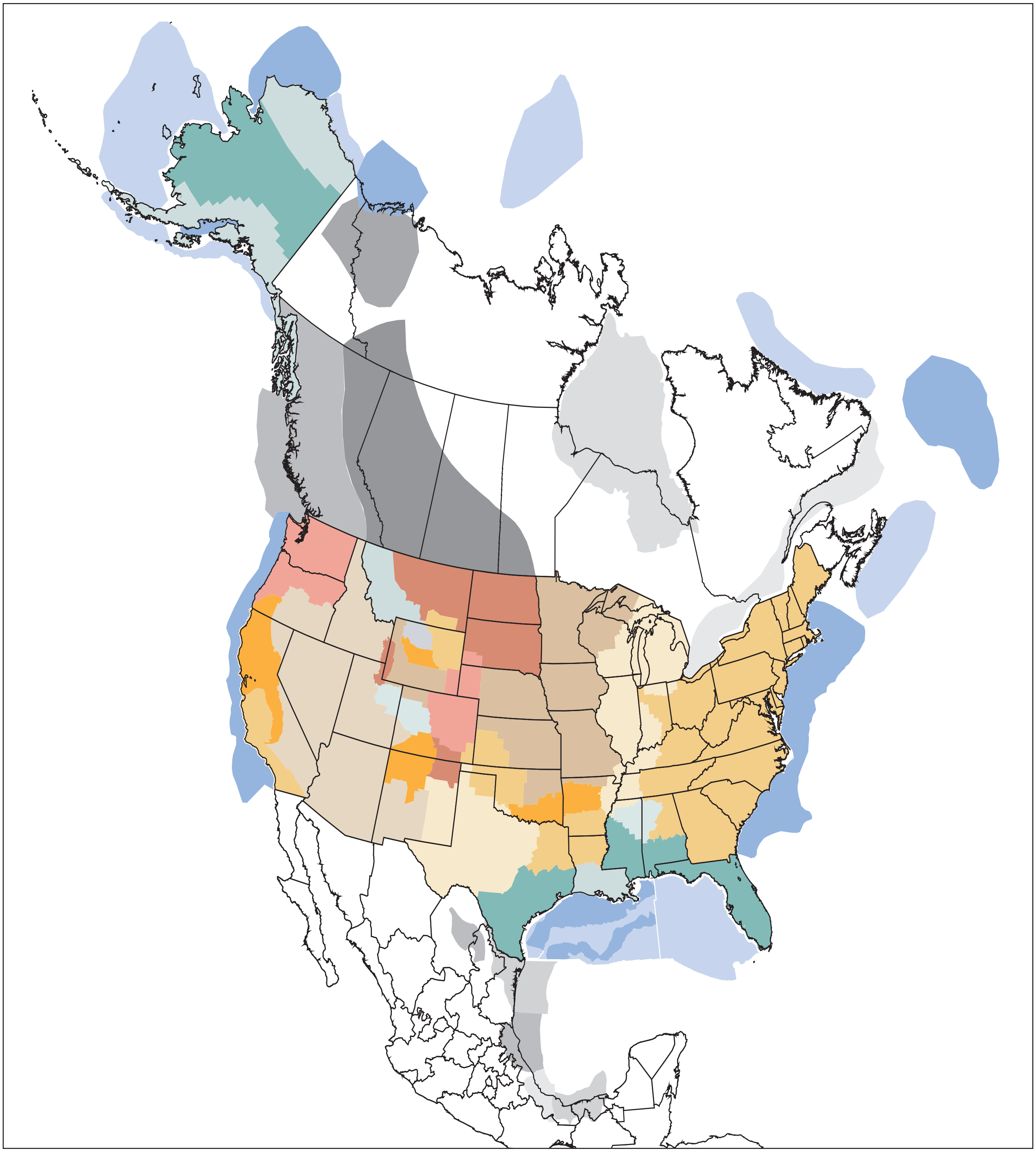


Figure S2-7. The 72 Supply Regions

regional and super-regional assessments were aggregations of USGS, MMS, or CGPC play assessments. In addition, it was decided to introduce more granularity in the 2003 study; consequently North America has been divided into 72 regions for modeling purposes. The 26 regions of the United States and Canada used in the 1999 NPC study are shown in Figure S2-8.

The EIA is a major data source for the study, providing such statistics as historical proved reserves,

Figure S2-8. The 1999 NPC Regions

production, and drilling activity. Figure S2-9 shows how the EIA divides the United States into regions. Reserves and production are generally reported by state, and in some cases the states are further subdivided into reporting districts. For example, Texas reports are broken into 10 Railroad Commission districts.

In order to compare results from the 1999 NPC study, and to obtain historical data from the EIA for

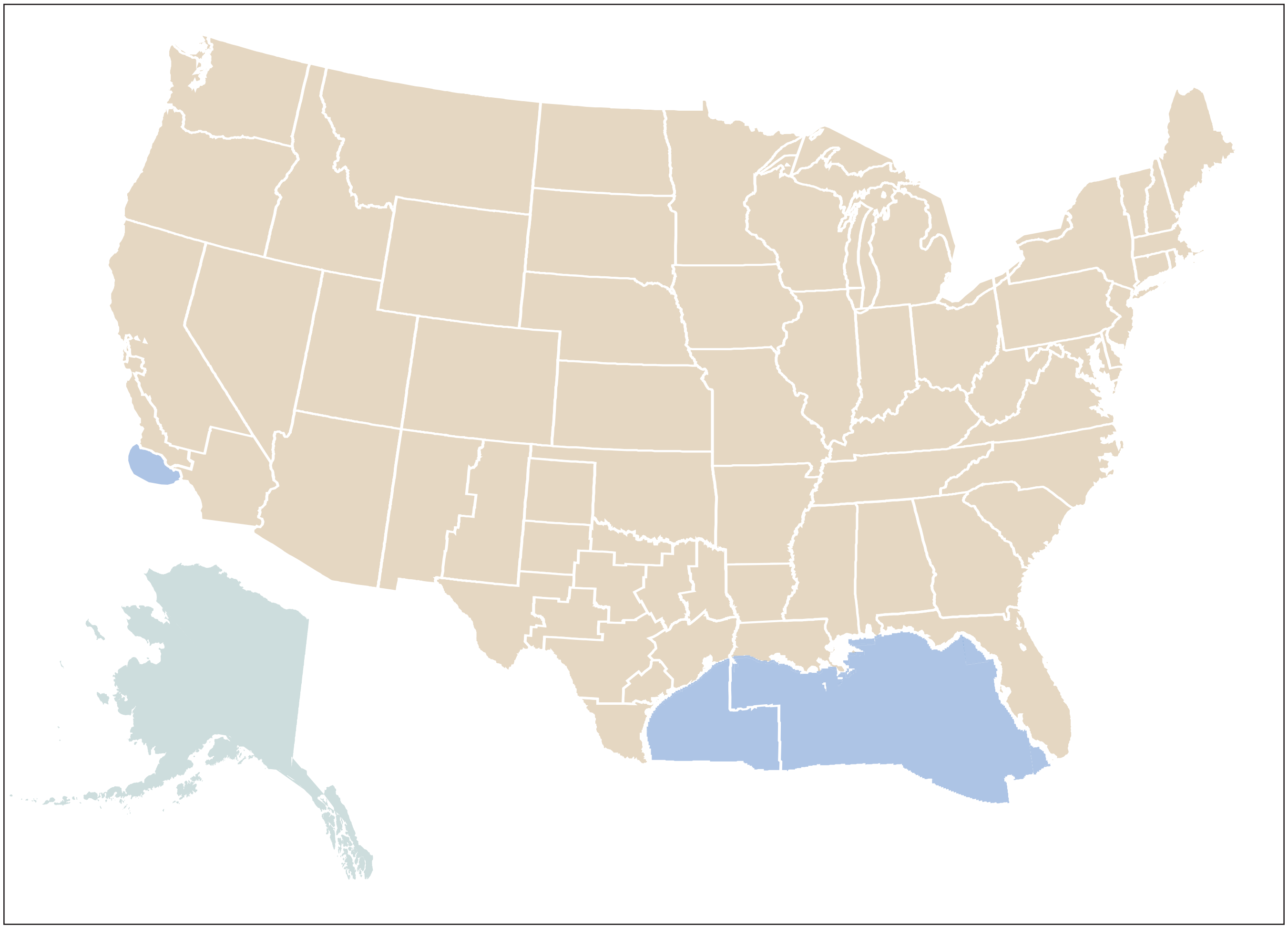


Figure S2-9. EIA Producing Regions

the current study's regions, the different regions shown in Figures S2-8 and S2-9 were apportioned into the 72 regions used in the current study.

B. Resource Comparisons

As described in Section IB, the technical resource available for potential future production comprises three categories (Proved, Growth, and Undiscovered). The distribution of technical resource between North American super-regions is shown in Figure S2-10. In terms of technical resource, the top three super-regions are the Gulf of Mexico (329 TCF), followed by Alaska with 303 TCF, and the Rockies with 284 TCF. Although each of these three super-regions contains a large technical resource base, their nature is quite different. In the Gulf of Mexico an increasingly larger proportion of new production will come from costlier, deeper water developments. In the Rockies, an increasingly larger proportion of new production will come from costlier nonconventional resources. While in Alaska, the hostile Arctic environment and lack of export pipeline capacity leave most of the resource currently stranded.

The following sections describe the distribution of Proved, Growth, and Undiscovered among the North American super-regions.

1. Proved

Figure S2-11 ranks the super-region by their proved gas reserves. The Western Canada Sedimentary Basin contains the most proved reserves (57 TCF), followed by the Rockies (50 TCF), the Gulf Coast Onshore (38 TCF), and the Gulf of Mexico (29 TCF). Alaska's proved reserves of 9 TCF include 2 TCF from south Alaska and 7 TCF from north Alaska that is fuel gas for ongoing oil production operations. North Alaska has an additional 33 TCF of discovered gas resource, which is not categorized as proved reserves by EIA because of the current lack of a pipeline to market.

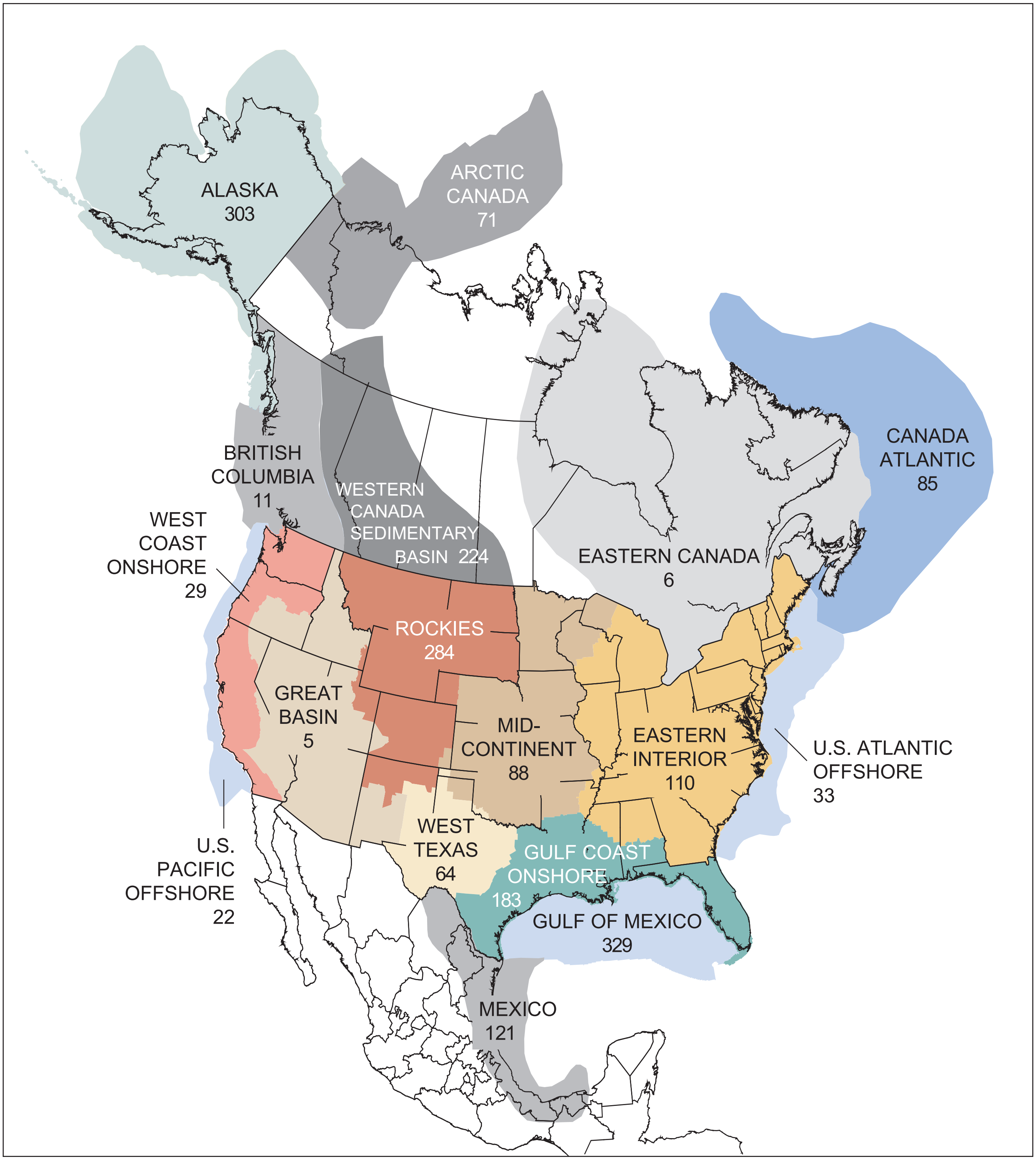
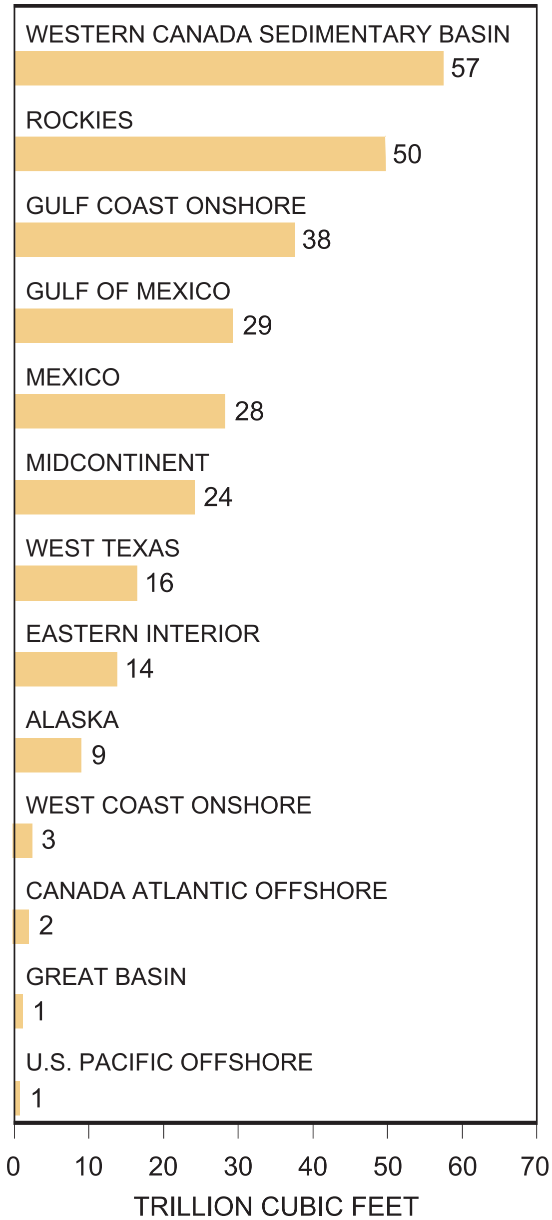


Figure S2-10. Super-Region Technical Resources (Trillion Cubic Feet)

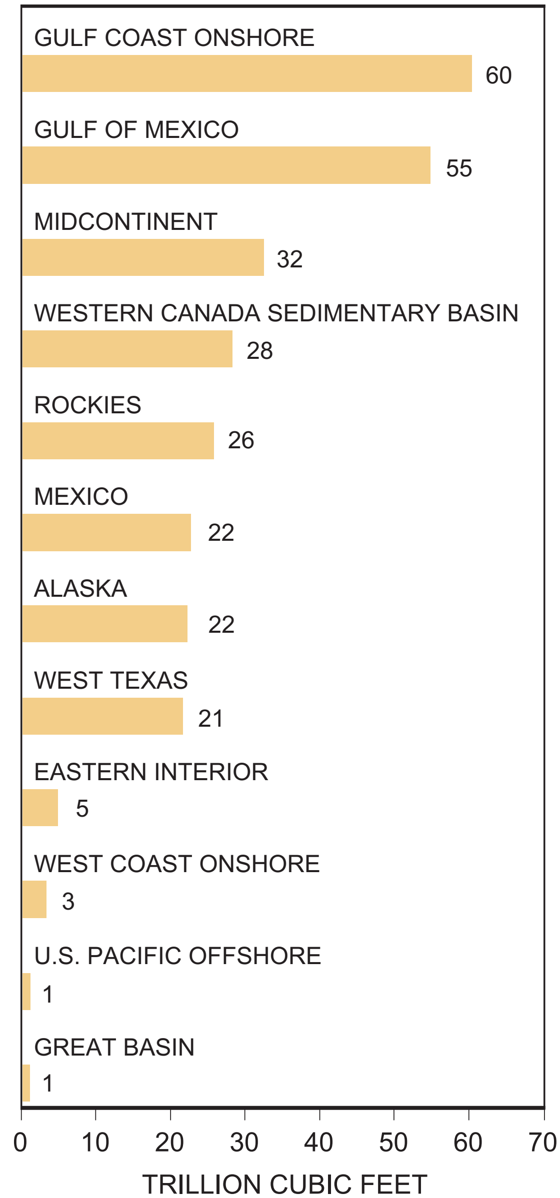
2. Growth

As described in Section IV, the estimates of estimated ultimate recovery (cumulative production + proved reserves) in existing fields tend to increase over time. This future increase in estimated ultimate recovery is known as growth. Figure S2-12 shows that 53% of the 277 TCF of reserve growth will come from three super-regions. The largest is the Gulf Coast Onshore



Sources: Energy Information Administration, Canadian Association of Petroleum Producers, and Pemex.

Figure S2-11. Super-Regions Ranked by Proved Reserves



Sources: NPC 2003 Reserve Growth Assessment, Energy Information Administration, Canadian Association of Petroleum Producers, and Pemex.

Figure S2-12. Super-Regions Ranked by Reserve Growth

(60 TCF), followed by the Gulf of Mexico (55 TCF) and the Midcontinent with 32 TCF.

3. Undiscovered

Figure S2-13 shows the super-regions ranked by volume of undiscovered technical resource. This technical resource is further split into conventional and nonconventional. Alaska ranks highest with 258 TCF, although 57 TCF of this is nonconventional. The Gulf of Mexico ranks second with 244 TCF, although it has the largest conventional resource of all super-regions. The Rockies ranks third with 209 TCF of undiscovered resource, 173 TCF of which is nonconventional.

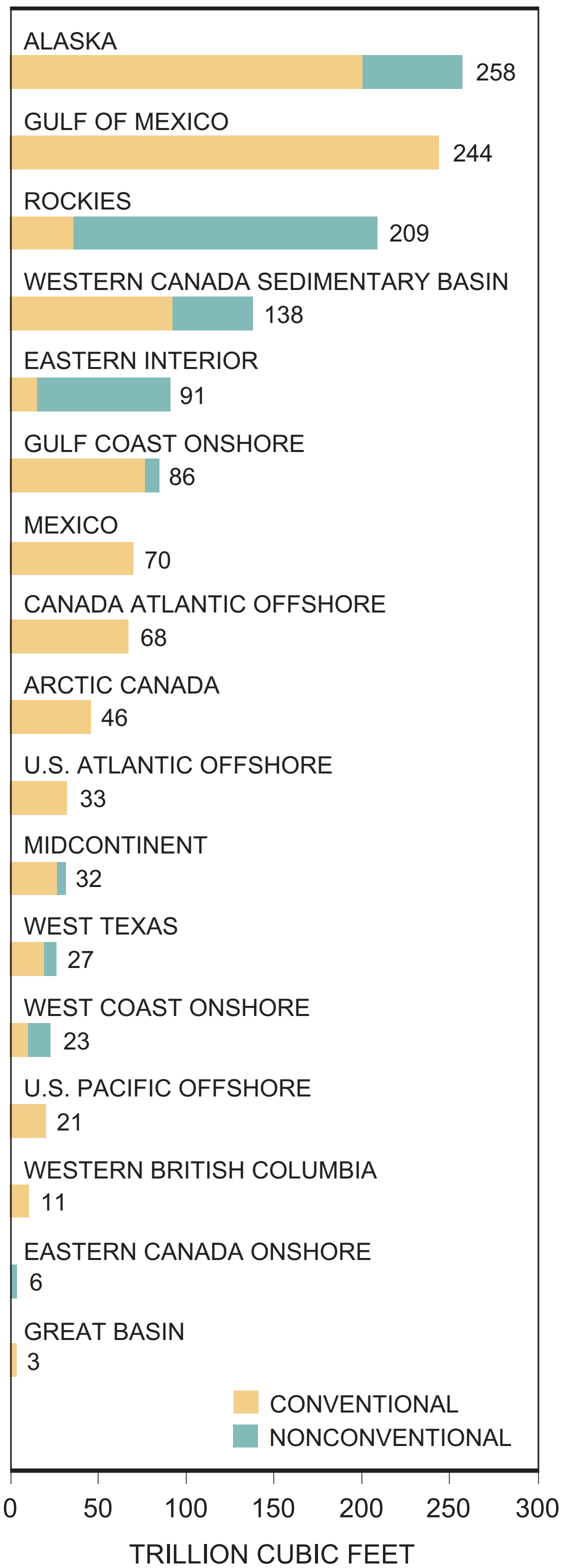


Figure S2-13. Super-Regions Ranked by Undiscovered Technical Resource

Figure S2-14 shows each super-region's relative contribution of undiscovered conventional resource. The Gulf of Mexico ranks first with 25%, followed by Alaska (21%) and the Western Canada Sedimentary Basin (9%). In contrast, Figure S2-15 shows the relative contribution of nonconventional undiscovered resource. Only ten of the seventeen super-regions have assessed nonconventional resource. In this case, the Rockies ranks first with 44%, followed by the Eastern Interior (20%), Alaska (15%), and the Western Canada Sedimentary Basin (12%).

C. Comparisons with the 1999 Study

The main reasons for differences between the 1999 NPC study and the 2003 NPC study undiscovered resource assessments are described in Section III.

Figure S2-16 compares 2003 and 1999 technical resource for each super-region based on current technology. Most of the 2003 assessments are smaller. Significant differences occur in both Arctic Canada and West Texas, although the underlying reasons are different. In Arctic Canada, the 2003 study concluded that the detailed assessment of undiscovered resource reported by the CGPC in 2001 was more realistic. In West Texas, the lower 2003 resource is due to a combination of smaller undiscovered and smaller growth. The 2003 study significantly reduced the number and size of remaining undiscovered fields, and reduced growth based on updated data and methodology.

Figure S2-17 compares 2003 and 1999 undiscovered conventional based on current technology. The 2003 assessments are similar to 1999 except for 5 super-regions where there has been a significant percentage reduction. The Arctic Canada and West Texas variances have been described earlier. The large relative reductions in conventional assessments of the Rockies, Eastern Interior, and Eastern Canada are attributable to updated USGS and CGPC assessments.

Figure S2-18 compares 2003 and 1999 undiscovered nonconventional. Again the 2003 assessments are similar to 1999 with 5 major exceptions. Four of these are reductions in the Western Canada Sedimentary Basin, Gulf Coast Onshore, West Texas, and Midcontinent. These reductions are all due to updated information and methodology. The Western Canada reduction is so significant that a second workshop was held in Calgary specifically to address this issue. The one significant increase from 1999 to 2003 occurs in the West Coast

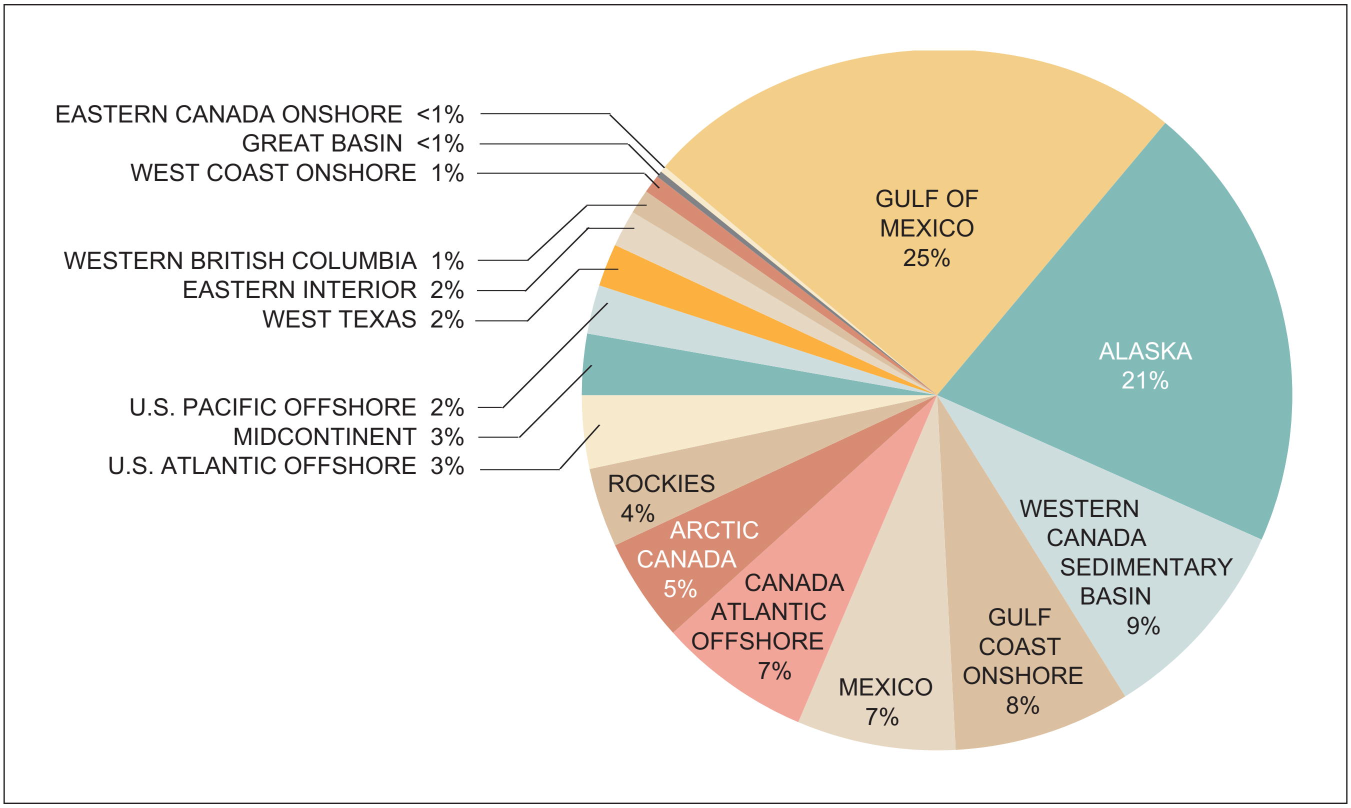


Figure S2-14. Distribution of Undiscovered Conventional Resource

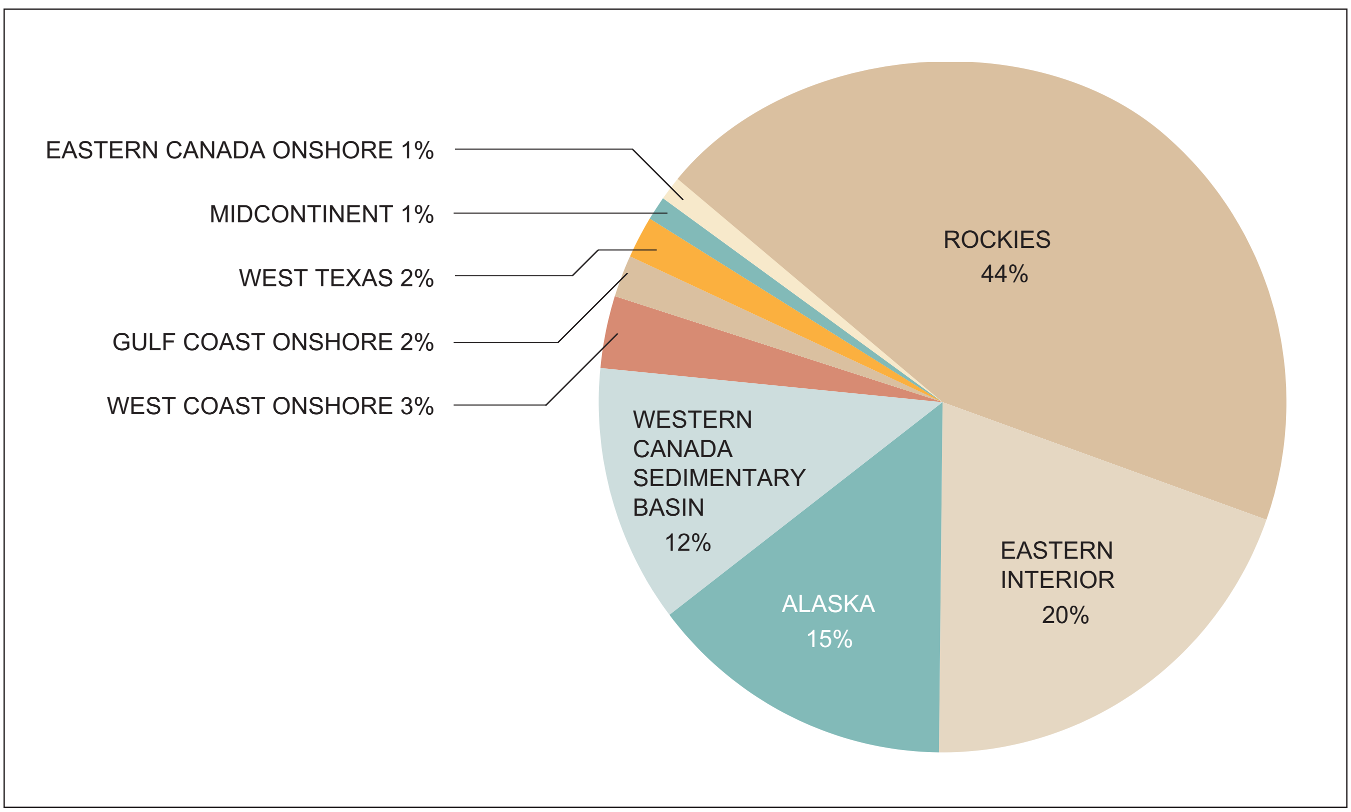


Figure S2-15. Distribution of Undiscovered Nonconventional Resource

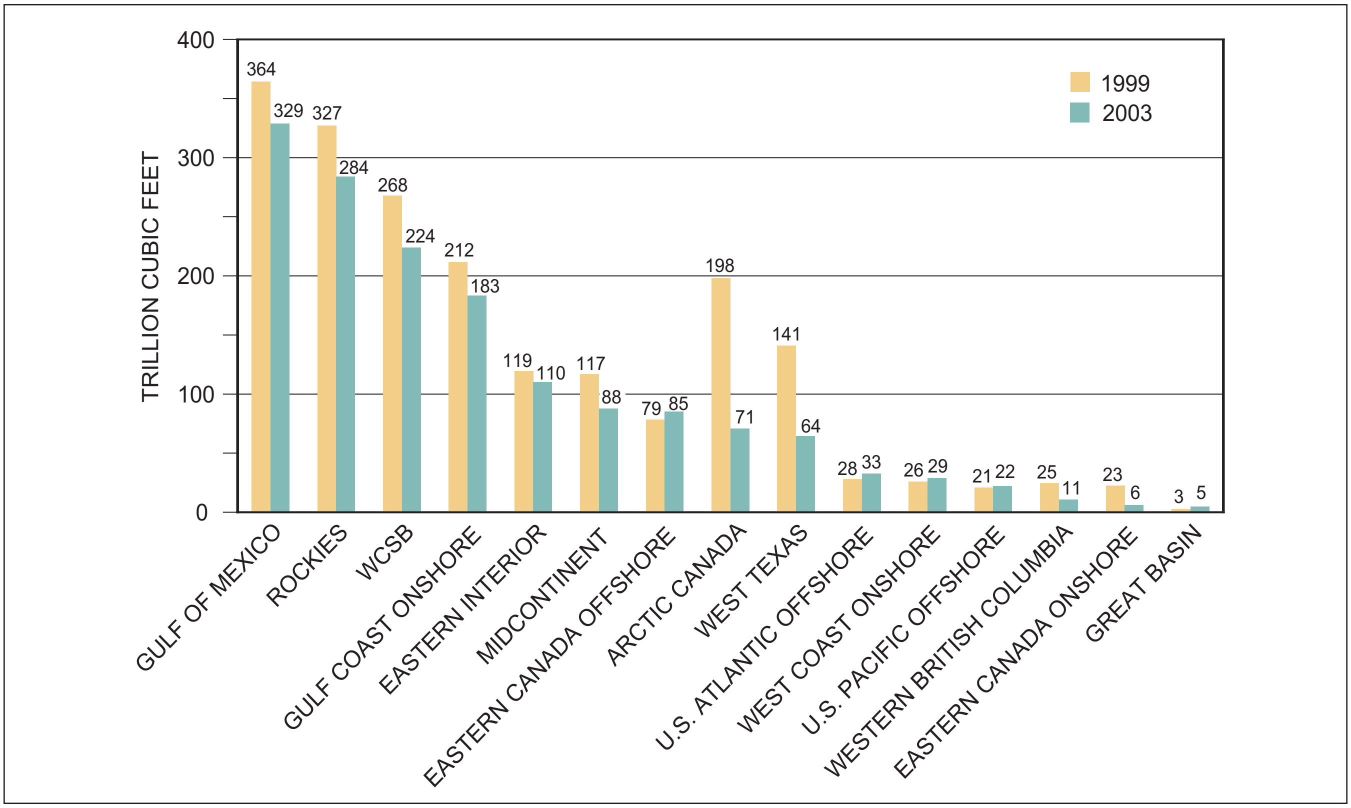


Figure S2-16. NPC 1999 vs. NPC 2003 Technical Resource by Super-Region

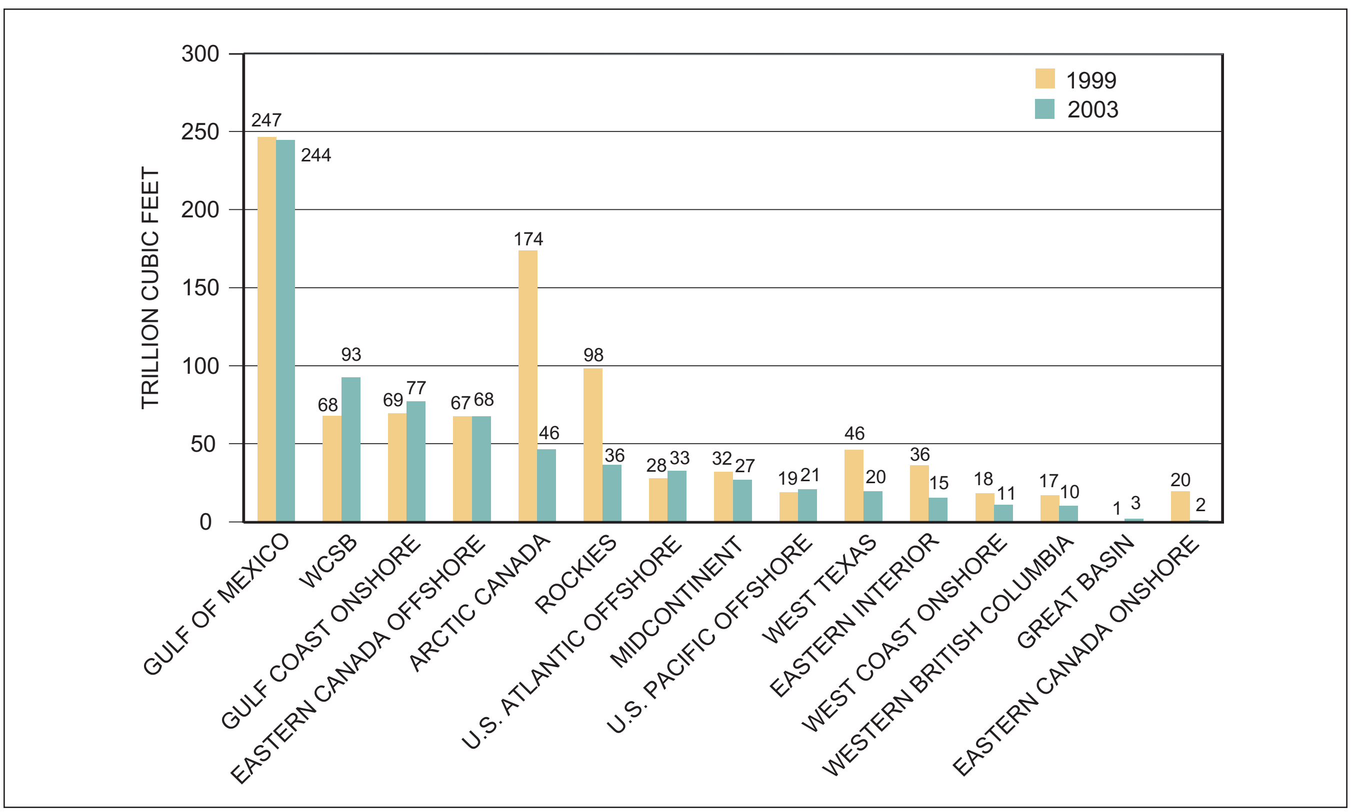


Figure S2-17. NPC 1999 vs. NPC 2003 Undiscovered Conventional Resource by Super-Region

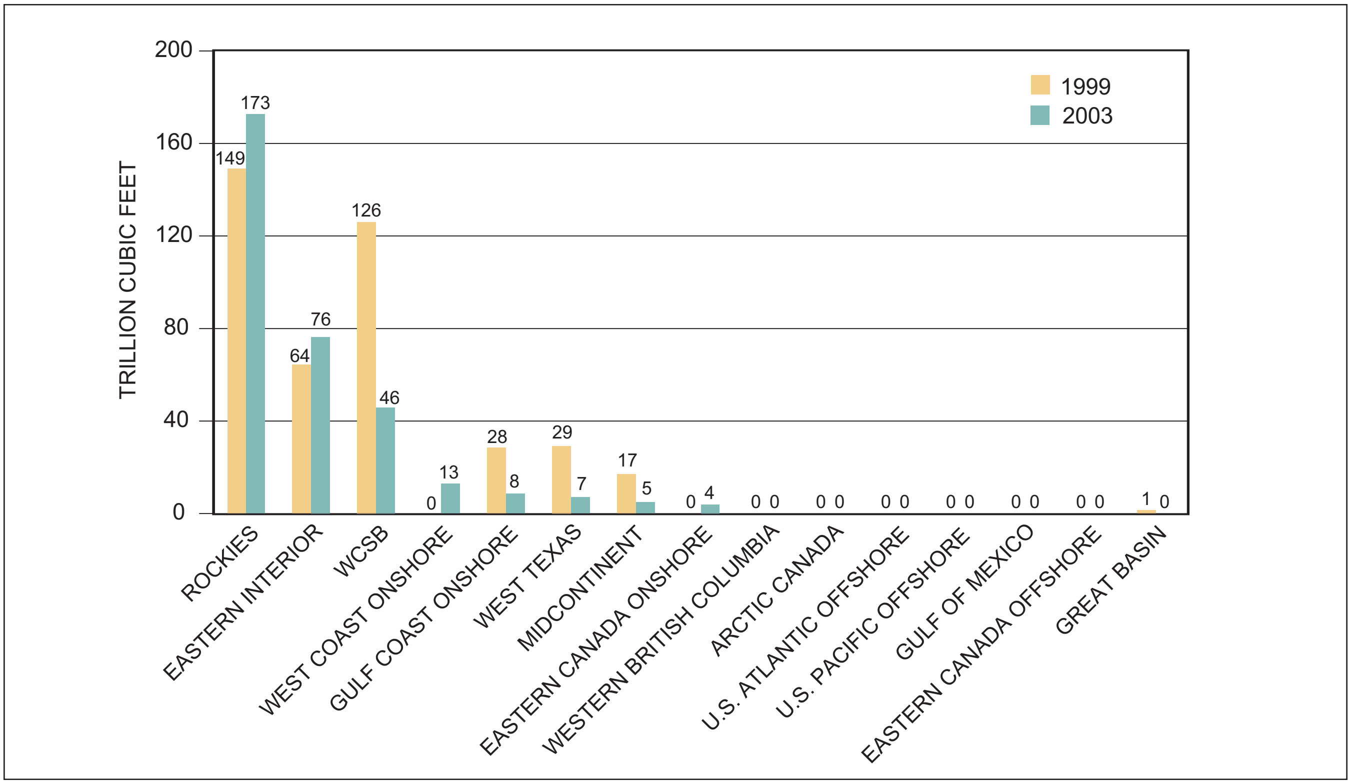


Figure S2-18. NPC 1999 vs. NPC 2003 Undiscovered Nonconventional by Super-Region

onshore, where an unusual high risk, high cost subvolcanic play has been identified.

Figure S2-19 compares 2003 and 1999 growth assessments. Generally the 2003 growth volumes are significantly lower than in 1999. These differences are mainly due to improved estimation methodology (Section IV).

Figure S2-20 compares 2003 and 1999 proved reserves by super-region. Proved reserves are reduced annually by the volume of production and increased by successful drilling of growth and new field (undiscovered) opportunities. In addition there may be other book-keeping positive or negative revisions not directly related to production or drilling. In a growing basin, proved reserve additions may outpace losses due to production. In a mature basin, the opposite may happen.

D. Production Forecast Comparisons

Figure S2-21 shows historical and forecast production for the 9 most significant super-regions. The Gulf of Mexico, WCSB, and Gulf Coast onshore are currently the largest producing super-regions, each contributing about 5 TCF/year. The Gulf of Mexico will continue to increase through 2010, but decline thereafter, although it will remain the largest producing super-region throughout the study period. In contrast, the onshore Gulf Coast has peaked and will decline through 2025.

The Rockies production has more than doubled since 1990 and will continue to grow to about 5 TCF/year in 2025. The Eastern Interior will also substantially increase its current production to nearly 2 TCF/year by 2025. Nonconventional resources characterize both the Rockies and Eastern Interior.

Alaska production is currently about 0.5 TCF/year, but will significantly ramp-up to over 2 TCF/year upon completion of a major pipeline to markets.

E. Drilling Activity Comparisons

Figure S2-22 shows historical and projected future number of gas wells drilled per year in the various super-regions. WCSB has been the most active with over 10,000 wells/year in recent years, most of which are relatively shallow and low cost. The Rockies super-region has nearly 6,000 wells/year in recent years drilled in a number of different regions comprising shallow

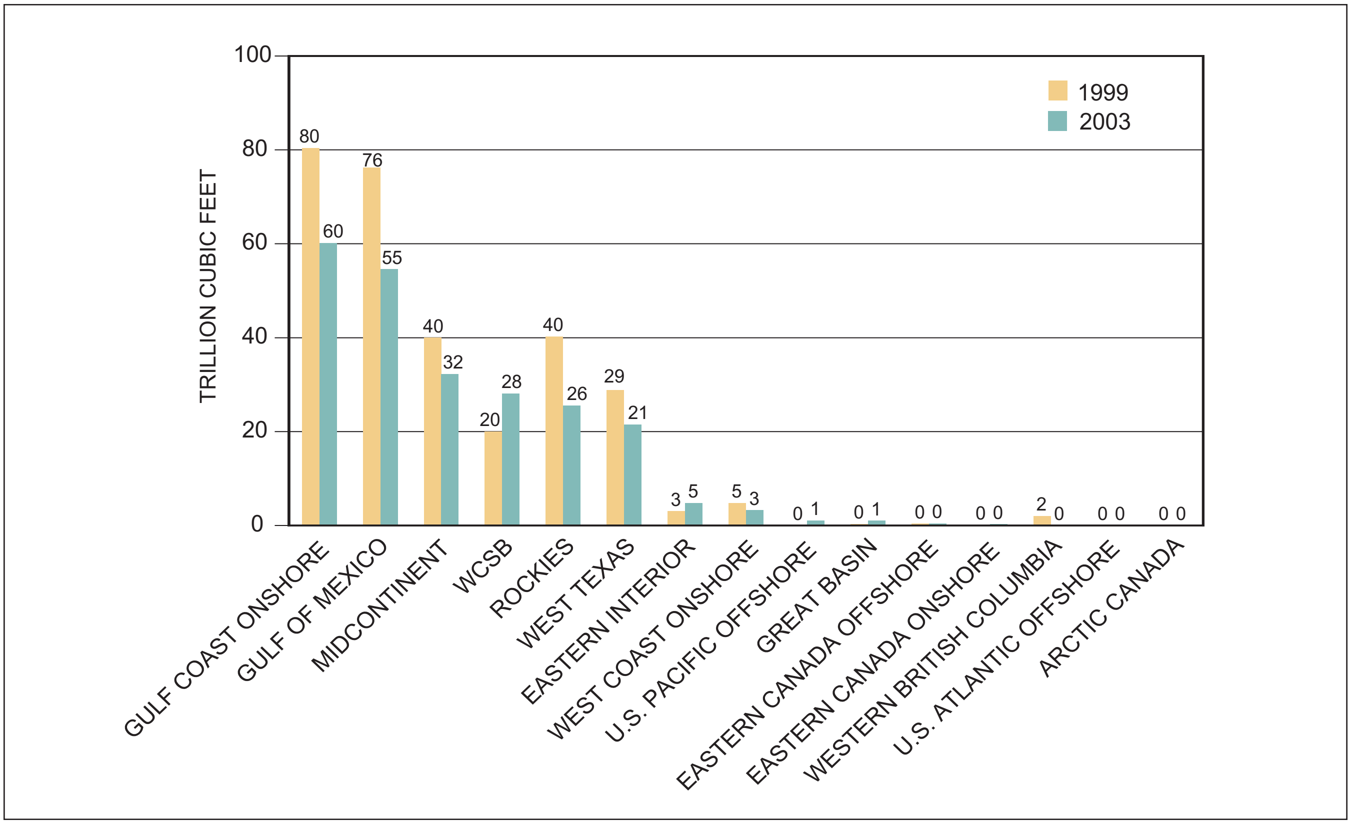


Figure S2-19. NPC 1999 vs. NPC 2003 Growth by Super-Region

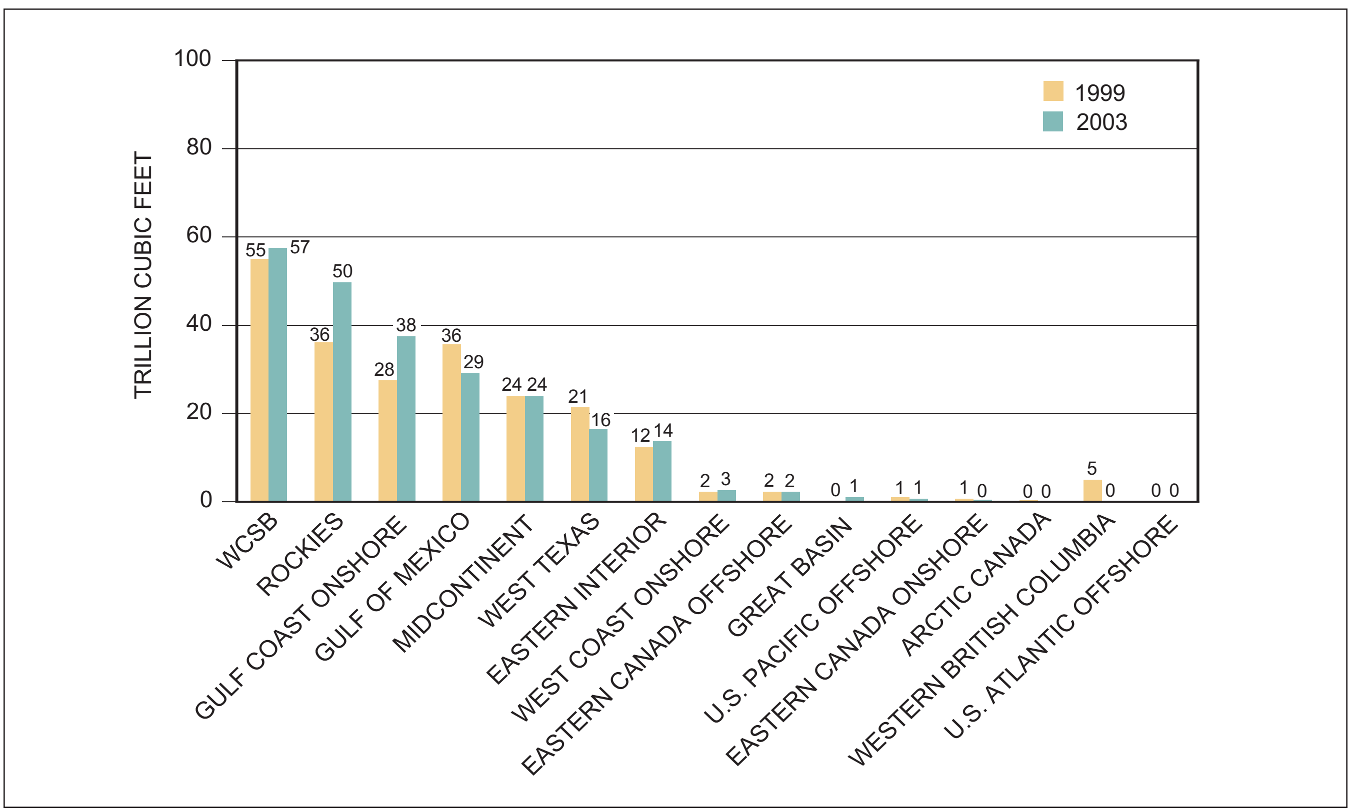


Figure S2-20. NPC 1999 vs. NPC 2003 Proved Reserves by Super-Region

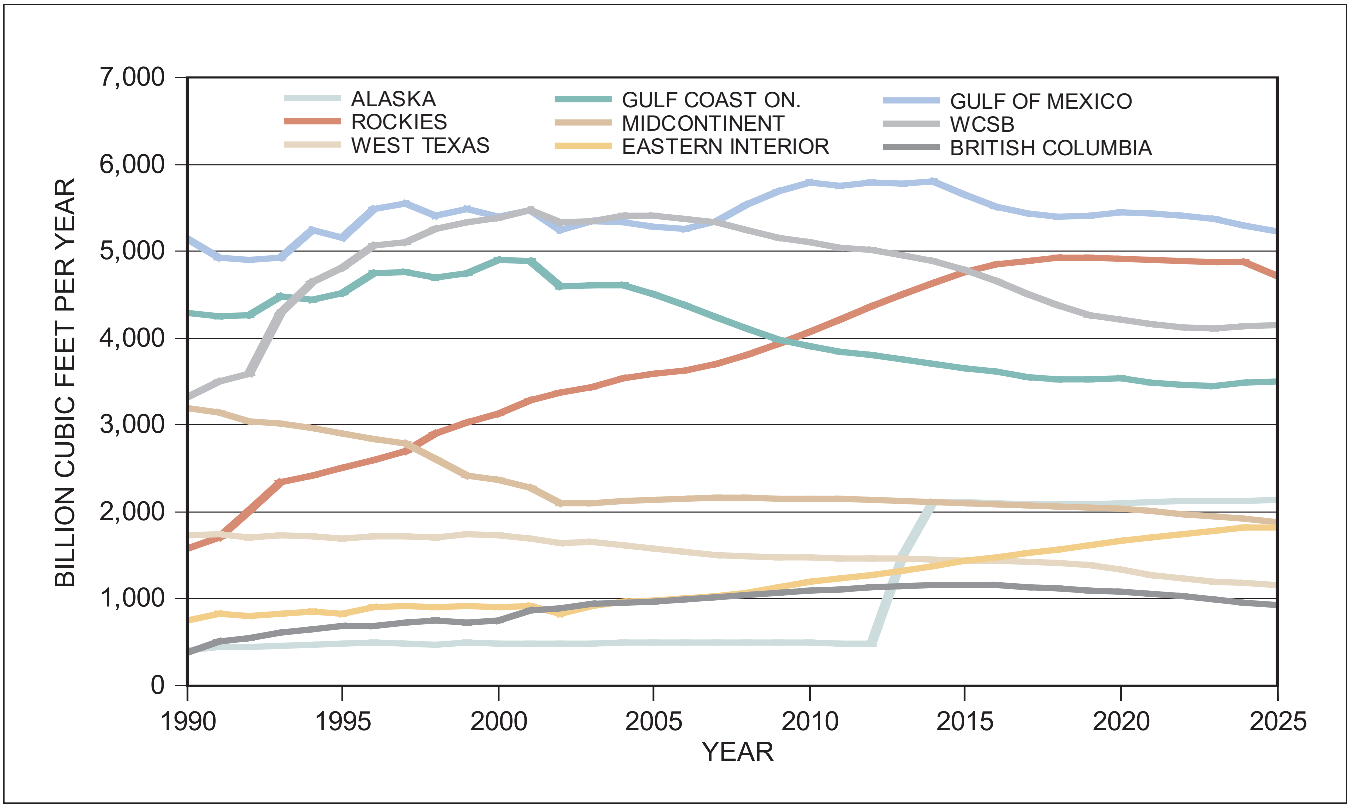


Figure S2-21. Production Forecast by Significant Super-Region

coal bed methane wells, basin-centered gas wells, and conventional gas wells. The Eastern Interior is the next most active super-region with most wells concentrated in the Appalachian region, which is mostly nonconventional fractured shale gas wells and coal bed methane wells. The Gulf Coast onshore recently has over 2,600 gas wells/year, which are dominantly conventional gas wells and are generally deeper than those from the previous regions. The Midcontinent recently has over 2,000 gas wells/year, which are mostly conventional gas wells in the Anadarko Basin and a combination of conventional gas wells and coal bed methane wells in the Arkoma Basin and Cherokee Platform. West Texas, with recently nearly 1,100 gas wells/year, has mostly conventional gas wells in the Permian Basin and mostly nonconventional fractured shale gas wells in the Fort Worth Basin. The Gulf of Mexico's recently nearly 400 gas wells/year are all conventional gas wells.

F. Main Conclusions from Super-Region Comparison

1. Of the total 1,969 TCF of North American technical resource, 14% is proved, 17% is growth, and 69% is undiscovered.
2. Four super-regions (Gulf of Mexico, Rockies, Western Canada Sedimentary Basin, and Alaska) contribute 62% of North America's undiscovered resource.
3. In terms of nonconventional resource, 4 super-regions (Rockies, Alaska, Gulf of Mexico, and Western Canada Sedimentary Basin) contribute 90% of the undiscovered potential.
4. The current North American proved reserves total of 272 TCF will grow by 277 TCF, or 102%. The Gulf of Mexico, Gulf Coast Onshore, Western Canada Sedimentary Basin, and Rockies contribute over 63% of proved plus growth, providing substantial near-term production volumes.
5. Although North American production will increase slightly by 2025, the relative contributions of the super-regions will change significantly. Decline will be most severe in the Gulf Coast Onshore, West Texas, and the Western Canada Sedimentary Basin. On the other hand, this will be compensated by production increases in the Rockies, Eastern Interior, Alaska, and Mexico.

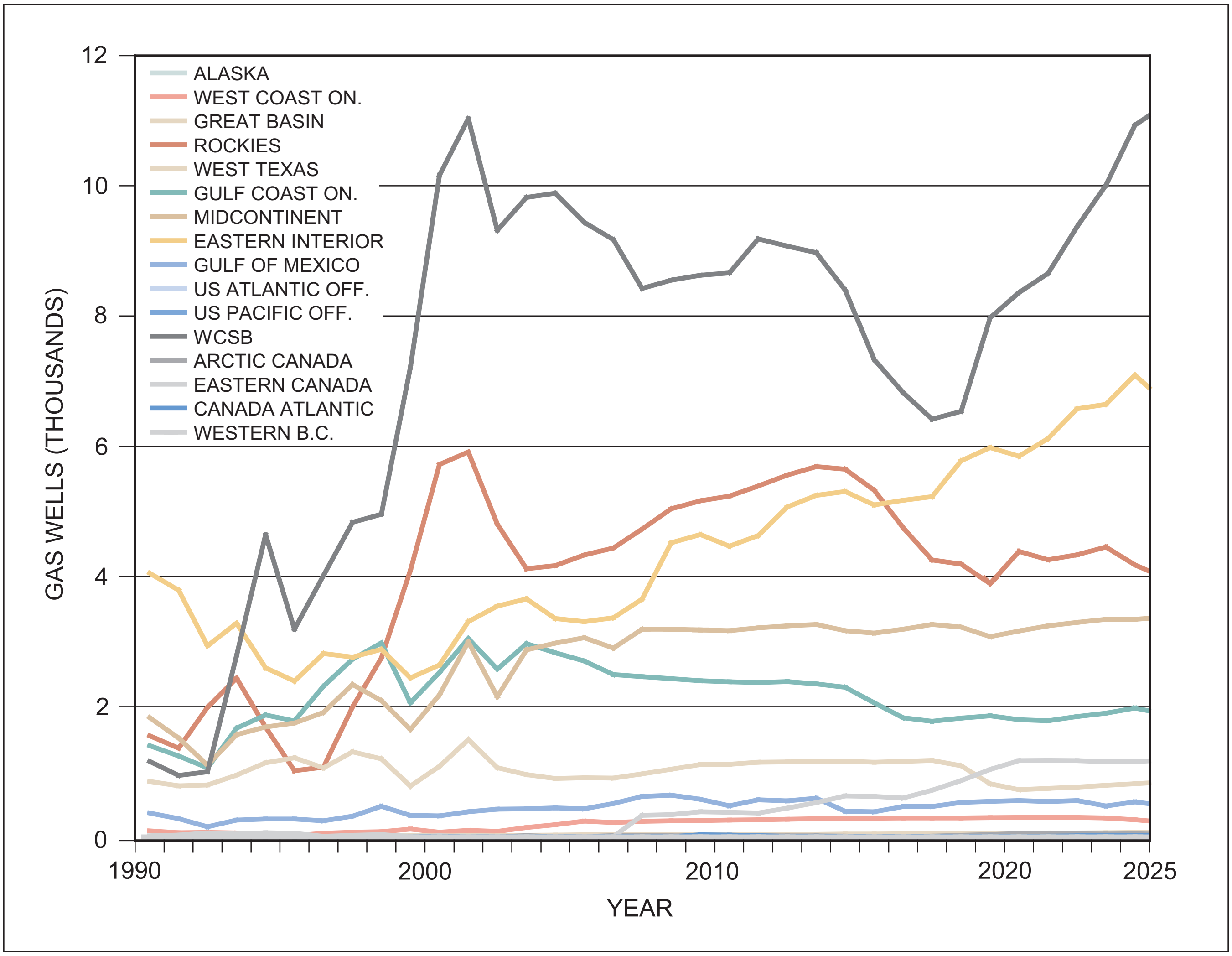


Figure S2-22. Gas Well Drilling History and Projection by Super-Region

III. Detailed Description of Plays and Regions within Each Super-Region

Section III contains descriptions of the 17 super-regions. Some descriptions are more detailed depending upon the significance of the super-region and the level of discussions during the workshop process. Each of the 17 sections contains index maps showing the super-region boundary and the regions within the super-region. Additional geological sub-divisions are also shown where they helped the assessment process. In order to provide context, production and drilling history/outlook graphs are included.

The super-region descriptions in this section are only designed to provide an overview of the USGS, MMS, and CGPC assessments forming the basis of the 2003 NPC Study; references to these detailed sources are included. However, variances to the USGS, MMS, and CGPC assessments are described in more detail.

A complete summary of cumulative production, proved resources, growth to proved reserves, and undiscovered gas can be found in Section V, "Technical Resource Charts." The three tables summarize these data at the country, super-region, and region level.

A. Alaska Super-Region

1. Super-Region Summary

The USGS and MMS assessment of undiscovered gas resources is the basis for the NPC assessment in Alaska. The NPC concentrated on northern Alaska for resource validation due to its large discovered and undiscovered gas resource. This includes onshore north Alaska and offshore Beaufort/Chukchi Seas (Figure S2-23). There is about 40 TCF of discovered resource on the North Slope of Alaska that has not been commercialized due to lack of a gas pipeline. North Alaska undiscovered gas resource of 213 TCF is about 83% of the total Alaska undiscovered gas resource of 258 TCF (Table S2-1). North Alaska conventional onshore is assessed at 72 TCF, North Alaska offshore at 96 TCF, and North Alaska onshore coal bed methane at 44 TCF. Total Alaska technical resource is 303.2 TCF and cumulative production has been 10.8 TCF.

The remote location, high development costs and land access issues have a large effect on gas economics in Alaska. A gas pipeline from Prudhoe Bay Field to the U.S. lower-48 states will require a significant investment and take over 10 years to design, permit and construct. Several seasonal operating restrictions both onshore and offshore apply to north Alaska. The primary gas market is in the U.S. lower-48 states, which at over 3000 miles distance creates commercial and logistical challenges.

The Reactive Path outlook assumes that an Alaska natural gas pipeline will be built and start deliveries in 2013 (Figure S2-24). Current production of about 0.5 TCF/year will increase to about 2.1 TCF/year and the current average of about 10 gas wells/year will increase to about 50 wells/year by 2025.

The USGS and MMS assessed a large number of plays in Alaska. The NPC combined these plays into six super-plays based on geology, development cost, technology factors and land access issues (Figure S2-25). North Alaska onshore has three major land ownership categories: National Petroleum Reserve Alaska (NPRA), Alaska state lands, and Arctic National Wildlife Refuge (ANWR). Both ANWR and portions of NPRA are currently under a moratorium.

2. Alaska Assessment Description

a. Proved Reserves

There are 8.8 TCF of proved reserves in Alaska. South Alaska (Cook Inlet area) has 1.9 TCF and North Alaska has 6.9 TCF which is derived from the Energy Information Administration state level reserves and field level information from the state of Alaska. Of the 6.9 TCF of North Alaska reserves, Prudhoe Bay Field accounts for approximately 4 TCF. In North Alaska, in addition to the 6.9 TCF of proved reserves there is an

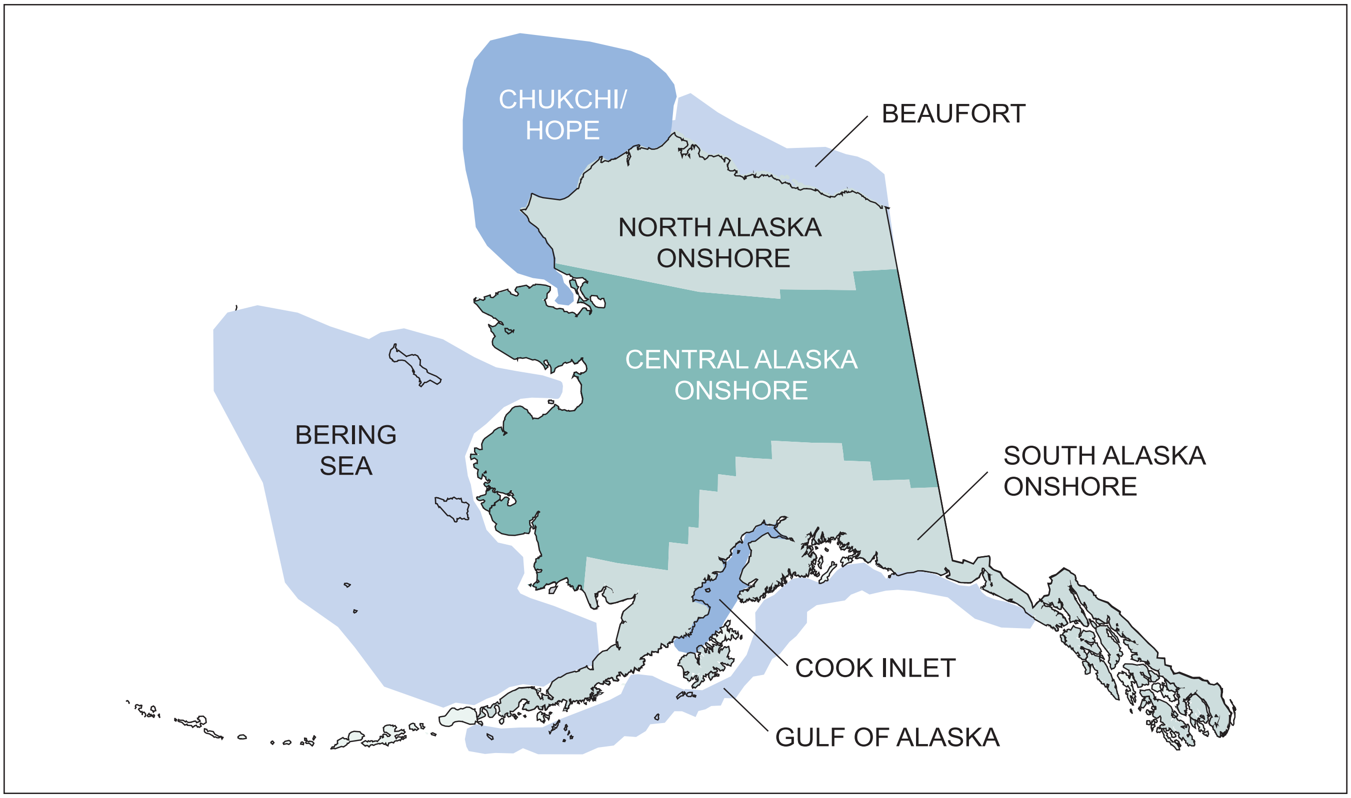


Figure S2-23. Alaska Regions

Alaska Region	USGS/MMS 1995-2002 (TCF)	NPC 2003 (TCF)
Onshore North Alaska Conventional	85.0	72.0
Onshore North Alaska Coal Bed Methane	Not assessed	44.5
Offshore Beaufort	41.9	31.3
Offshore Chukchi/Hope	65.2	65.2
Subtotal North Alaska	**192.1**	**213.0**
Offshore Bering	18.8	20.1
Offshore Cook Inlet	1.4	1.5
Offshore Gulf of Alaska	6.8	7.3
Onshore Central Alaska	2.4	2.8
Onshore South Alaska Conventional	1.9	0.9
Onshore South Alaska Coal Bed Methane	Not assessed	12.5
Total Alaska	**223.4**	**258.0**

Table S2-1. Alaska Undiscovered Gas – Comparison of NPC and USGS/MMS

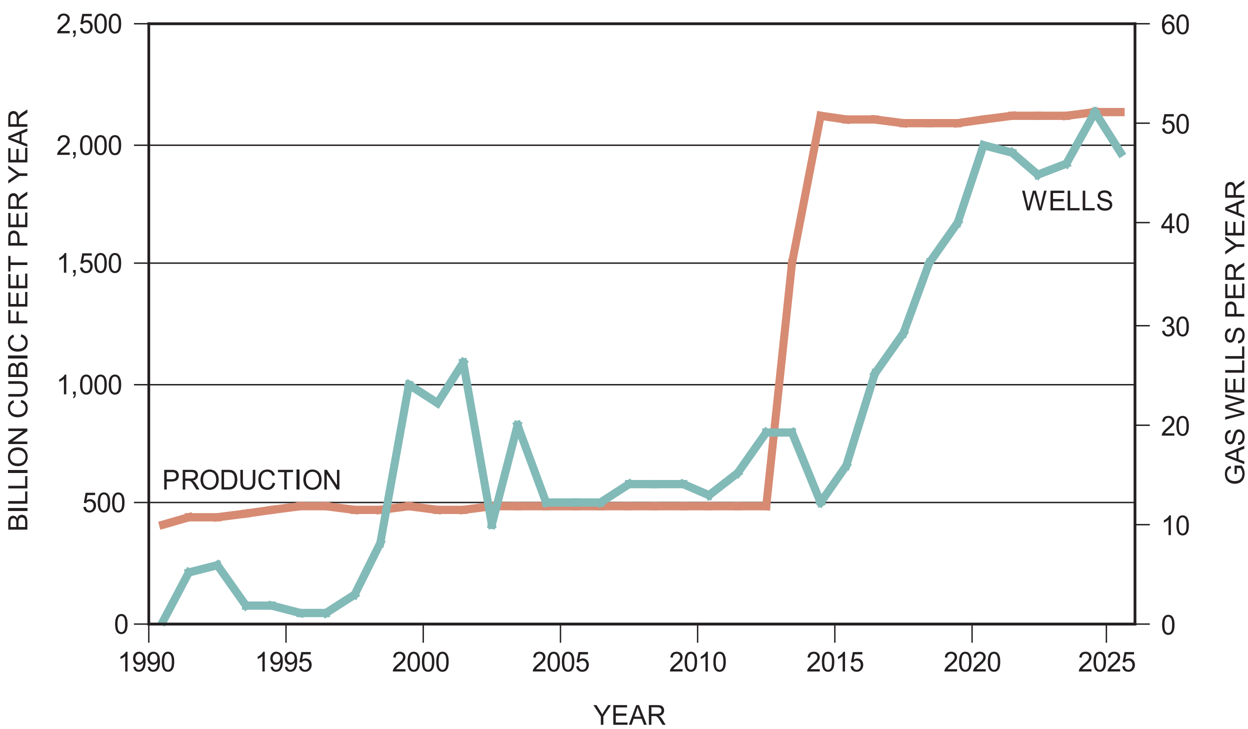


Figure S2-24. Alaska Production and Drilling Forecast

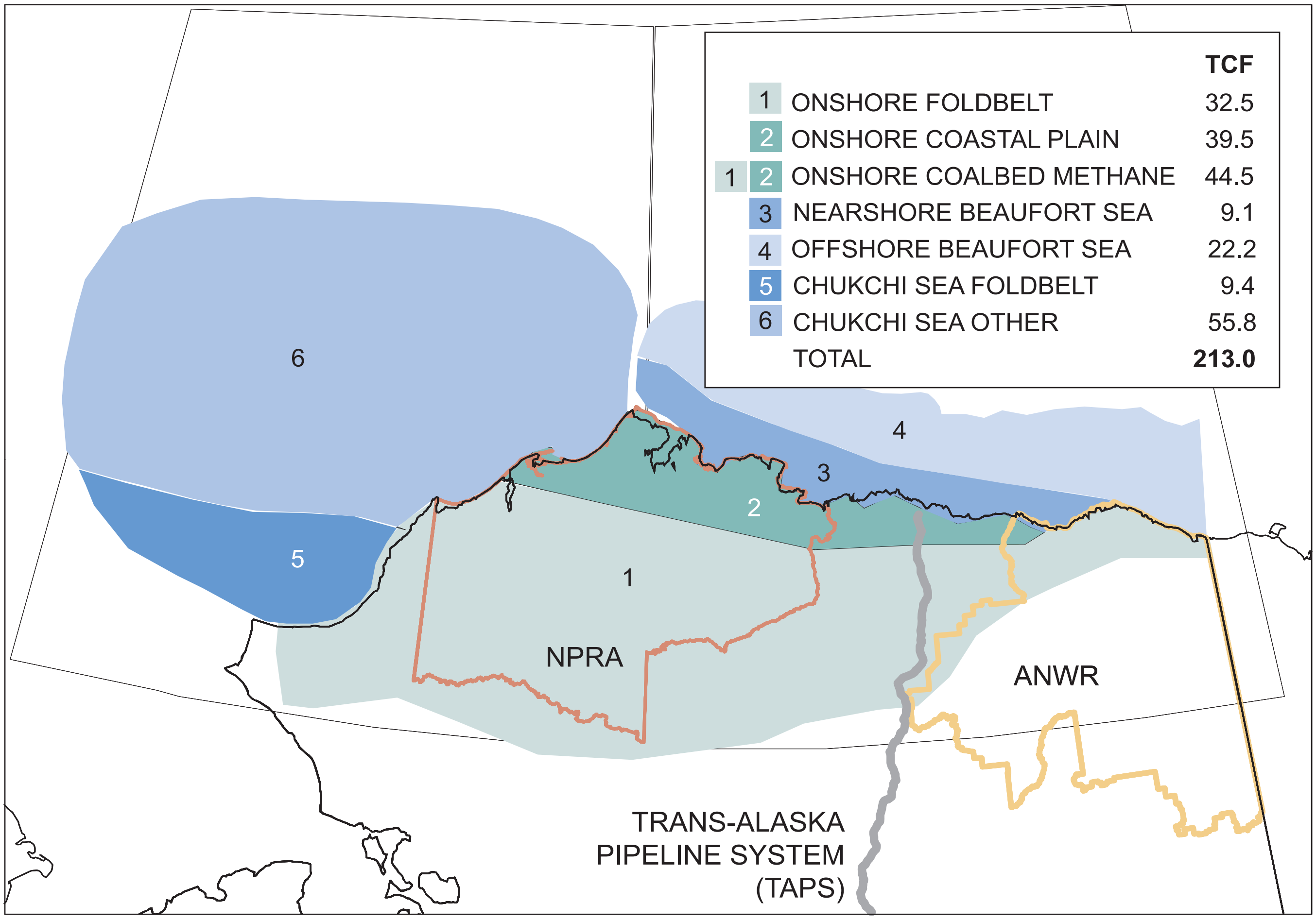


Figure S2-25. North Alaska Super-Plays

additional 33 TCF of discovered gas which can not be classified as proved reserves in the Prudhoe Bay area, Pt. Thomson Field, and offshore Chukchi Sea (Burger Field).

b. Growth of Existing Fields

Most of the known fields in north Alaska are oil fields with the associated gas being reinjected to enhance liquids recovery until there is an economically viable transportation system to the large gas markets. Growth for Alaska is 22 TCF including discovered gas in Prudhoe Bay and nearby fields (19.9 TCF), which cannot yet be classified as proved reserves because of lack of pipeline. The remaining growth of 2.1 TCF is from fields in the Cook Inlet area of South Alaska.

c. Undiscovered Fields Background Studies

Assessments by the USGS were used as the basis for the assessment of onshore Alaska. The USGS assessed all of onshore Alaska with its 1995 U.S. national assessment (http://energy.cr.usgs.gov/oilgas/noga/index.htm). In 1998 there was a reassessment of the 1002 area of the ANWR (coastal plain portion) (http://energy.cr.usgs.gov/oilgas/noga/index.htm). In 2002 there was a reassessment of the NPRA (http://wrgis.wr.usgs.gov/open-file/of02-207/). These three studies were used as the basis for determining the undiscovered resource potential of onshore Alaska.

Assessments by the MMS updated in 2000 were used as the basis for the assessment of offshore Alaska (http://www.mms.gov/revaldiv/RedNatAssessment.htm). A more detailed report for offshore Alaska with play level analysis is documented at http://www.mms.gov/alaska/re/reports/rereport.htm.

The NPC methodology was to assemble industry and government Alaska experts and hold a three-day workshop specifically for north Alaska (onshore north Alaska and offshore Beaufort/Chukchi) to validate and change, if necessary, the mean resource estimates for key large plays. This workshop was held at the USGS office in Menlo Park, California.

d. Undiscovered Fields Results

The USGS/MMS assessed a total of 60 plays in north Alaska. The NPC combined those plays into groups of similar age and/or structural styles which are referred to as super-plays. The 6 super-plays are: Onshore Foldbelt, Onshore Coastal Plain, Nearshore Beaufort Sea, Offshore Beaufort Sea, Chukchi Sea Foldbelt, and Chukchi Sea Other (Figure S2-25).

The NPC reduced the USGS/MMS estimate of undiscovered gas in north Alaska by 21 TCF: The Onshore Foldbelt was reduced by 11 TCF, the Nearshore Beaufort Sea was reduced by 4 TCF, and the Offshore Beaufort Sea was reduced by 6 TCF. The other super-plays were not changed.

The Onshore Foldbelt super-play was reduced because the NPC experts questioned the USGS assessment of 28 undiscovered gas fields with an average size of 1 TCF. It was noted that foldbelt gas fields in the Canadian Beaufort Sea average about 700 BCF in size. The largest known gas field in the Alaska onshore foldbelt is Gubik Field with an estimated size of 600 BCF. Most other discoveries are significantly smaller. The NPC consensus was 28 undiscovered gas fields with an average size of 700 BCF for a total of 20 TCF of undiscovered gas for the NPRA and adjoining Alaska state lands. The ANWR portion of the foldbelt was assessed by the NPC at 5 TCF of undiscovered gas due to reservoir risk as a result of deep burial of potential reservoir rocks and subsequent uplift to current depths. This results in a total assessment of 25 TCF for the foldbelt.

The NPC reduced the MMS Beaufort Sea assessment by 10 TCF. The Nearshore Beaufort Sea was reduced by 4 TCF. The major factor in this reduction was that the NPC thought the future wildcat success rate should be about 25% instead of the 40% the MMS used. The offshore Beaufort Sea was reduced by 6 TCF. The reason for the reduction was the same as for the nearshore Beaufort Sea.

e. Alaska Coal Bed Methane Potential

Alaska has huge coal resources (5,500 billion short tons) with the majority of these resources concentrated in the North Slope onshore and the Cook Inlet area of southern Alaska (Clough and others, 2000). A recent assessment estimated 1037 TCF for coal bed gas-in-place in Alaska of which about 78% is in the North Slope and 22% in the Cook Inlet area (Clough and others, 2000). The NPC has adopted a recoverable coal bed methane estimate of 57 TCF for Alaska (Potential Gas Agency, 2002) and used the 78% and 22% factors to assign 44 TCF technically recoverable gas to the North Slope and 13 TCF to the Cook Inlet area, respectively.

Coal bed methane development in Alaska is at a very early stage. There is a coal bed methane drilling project in the Cook Inlet area (Pioneer prospect) which is in the evaluation stage. There is interest in coal bed methane for rural communities in Alaska. The Alaska Division of Geological and Geophysical Surveys (a division of the Alaska Department of Natural Resources) in cooperation with the USGS and the Bureau of Land Management is evaluating this potential by focusing on three areas: Wainwright in the western North Slope, Fort Yukon in central Alaska and the Chignik area on the Alaska peninsula. Large-scale commercial development of coal bed methane in Alaska faces numerous technical and economic obstacles but is a potentially huge resource which is under study at the present time.

3. References

Clough, J.G. and others, August 2000, Alaska Methane Remains Untapped, AAPG Explorer.

Potential Gas Agency, 2002, A Comparison of Estimates of Ultimately Recoverable Natural Gas in the United States: Colorado School of Mines, Potential Gas Agency, Gas Resource Studies 1, 27 p.

B. U.S. Offshore Pacific Super-Region

1. Super-Region Summary

The MMS assessment of gas resources provides the basis for the NPC assessment of the Offshore Pacific (Figure S2-26). The undiscovered gas resource is about 20.7 TCF. Most of the potential is offshore southern California and is gas associated with oil fields. This potential lies in water depths from 300 to over 4,200 feet. Total remaining technical resource is 22.3 TCF and cumulative production has been 2.6 TCF.

Offshore Washington, Oregon and northern California have had limited exploration (Figure S2-27). There have been a total of 20 exploratory wells drilled in these areas, mostly in the mid 1960s. The wells are located in water depths of less than 600 feet. There have been no gas or oil discoveries to date in these areas, although some of the wells did have gas shows.

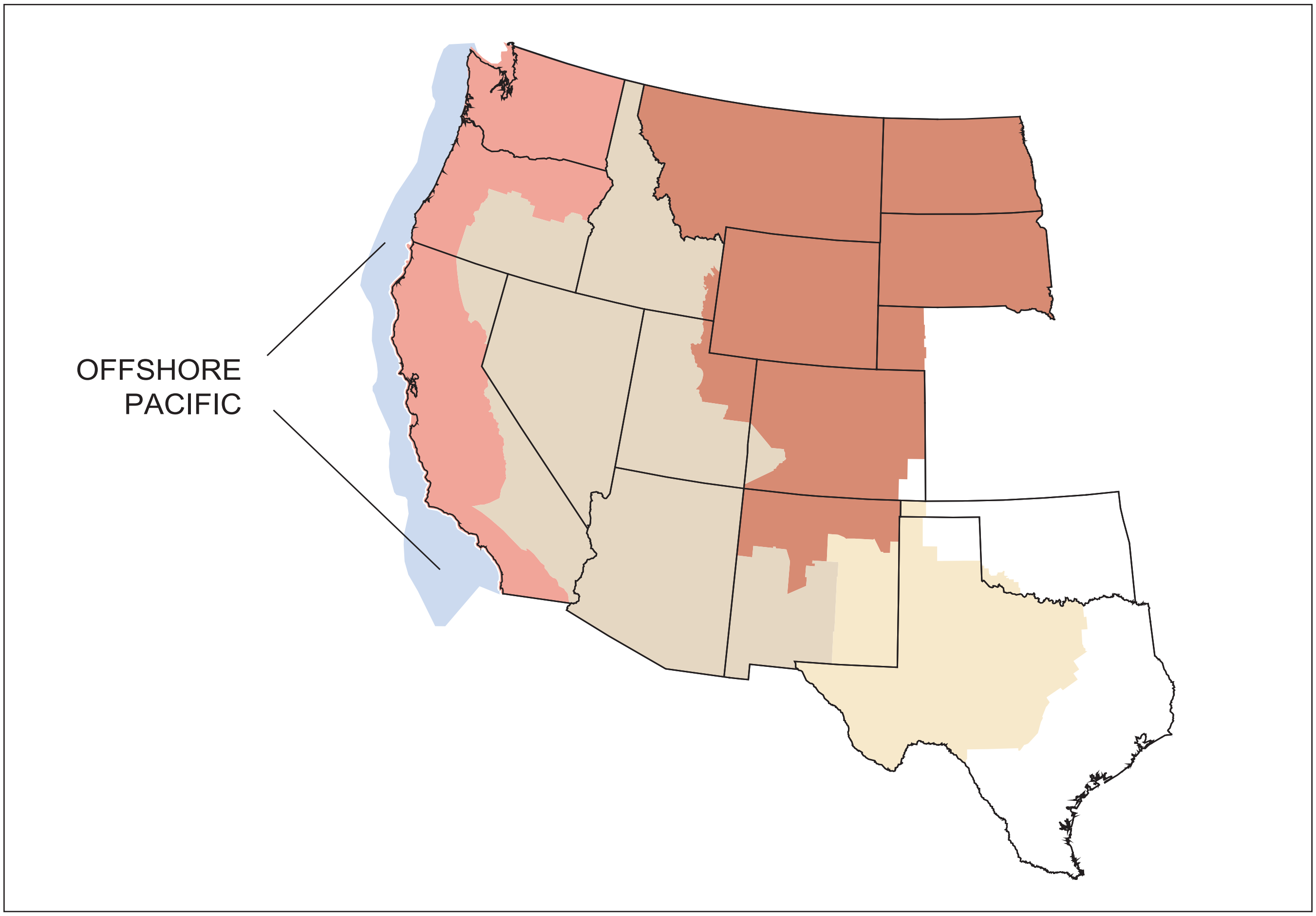


Figure S2-26. Location of the U.S. Offshore Pacific Super-Region

The 52 MMS plays were combined into 3 super-plays based on geology, cost, location, and access: Offshore Oregon-Washington, Offshore Central California, and Offshore Southern California (Table S2-2).

The Reactive Path outlook is for a continued production decline from the today's level of about 40 BCF/year to around 20 BCF/year by 2025 (Figure S2-28). An average of 1 gas well/year post-2010 would be required to maintain the production outlook.

2. Offshore Pacific Assessment Description

a. Remaining Gas Reserves

There are 0.6 TCF of remaining proved gas reserves in Offshore Southern California. There are no proved reserves in the other areas of the offshore Pacific. In addition, there are about 0.9 TCF of discovered non-proved reserves in offshore southern California. These are not yet developed due to regulatory issues. The most recent MMS reserve estimation for the offshore Pacific is at http://www.mms.gov/omm/pacific/offshore/ofr98rpt.htm.

b. Growth of Existing Fields

There are a total of 12 fields producing in the offshore Pacific which have produced a total of 2.6 TCF to date. Growth is calculated only for producing fields. The total growth in these fields is estimated to be 1.0 TCF.

c. Undiscovered Fields Background Studies

Assessments by the MMS updated in 2000 were used as the basis for the assessment of offshore Pacific (http://www.mms.gov/omm/pacific/offshore/na/pdfs/MMS2001-014.pdf). A more detailed report for the offshore Pacific with play level analysis is "1995 National Assessment of Oil and Gas Resources of the Pacific Outer Continental Shelf," OCS Report MMS 97-0019 (http://www.mms.gov/omm/pacific/offshore/na/na95ocsreport.htm).

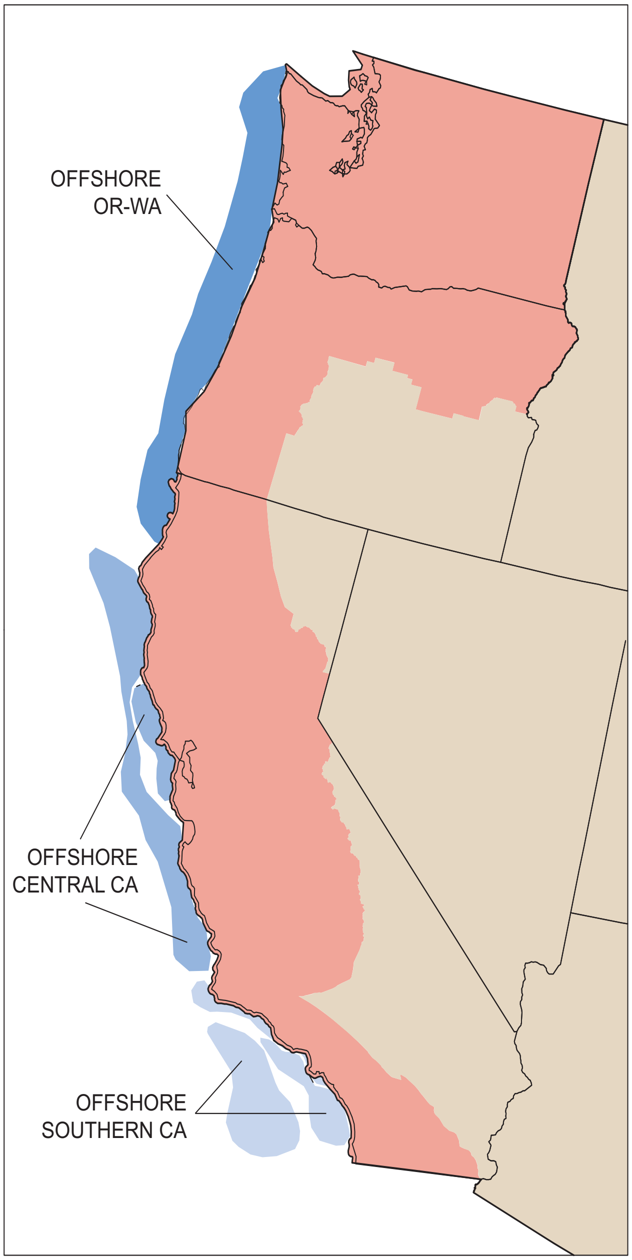


Figure S2-27. Offshore Pacific Super-Plays

The NPC did not hold an industry workshop on the offshore Pacific but accepted the MMS assessment as the basis for our estimate of undiscovered resources.

d. Undiscovered Fields Results

The MMS estimated that there is 18.7 TCF of undiscovered gas resource in the offshore Pacific (fields larger than 6 BCF for gas or 1 MMBO for oil fields). The NPC accepted the MMS assessment without change.

C. West Coast Super-Region

1. Super-Region Summary

The West Coast super-region (Figure S2-29) covers all or most of California, Oregon, and Washington (Figure S2-30). California is a significant oil producer in the United States. Total remaining technical gas resource is 29.1 TCF and cumulative production is 31.9 TCF.

The USGS 1995 resource assessment provides the basis for NPC's West Coast assessment. The NPC total undiscovered gas is 23.3 TCF. About half of this total is in conventional plays in California and the other half is in a nonconventional tight sandstone play in eastern Oregon and Washington.

In the Reactive Path outlook, today's production level of about 300 BCF/year will increase to about 500 BCF/year by 2020 (Figure S2-31). Drilling activity will approximately triple from about 100 wells/year currently to about 300 wells/year.

2. West Coast Assessment Description

a. Remaining Gas Reserves

There are 2.7 TCF of remaining proved gas reserves in the West Coast.

Offshore Pacific Super-Play	MMS 2000 (TCF)	NPC 2003 (Includes Small Field Adjustment) (TCF)
Offshore Southern California	10.3	11.3
Offshore Central California	6.3	6.9
Offshore Oregon-Washington	2.3	2.5
Total	**18.9**	**20.7**

Table S2-2. Undiscovered Gas by Super-Play – Comparison of NPC and MMS

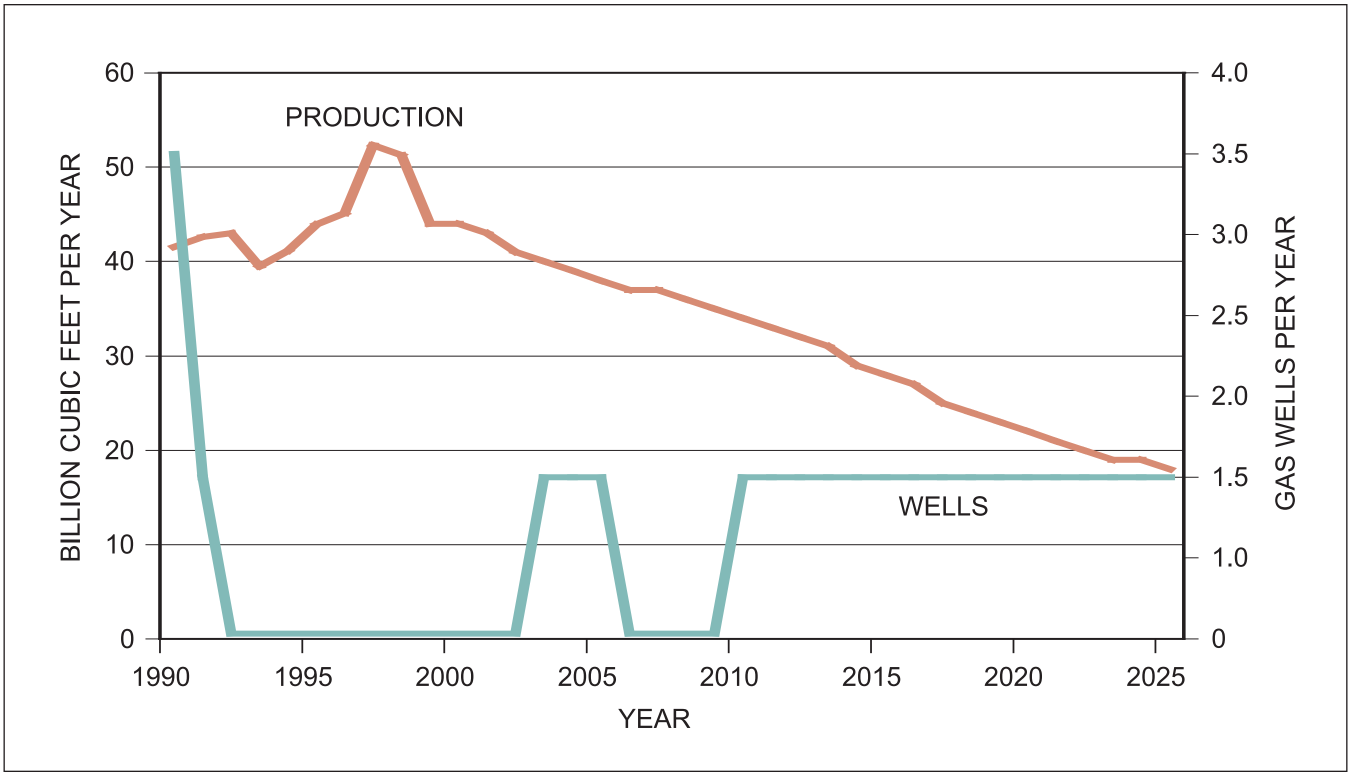


Figure S2-28. U.S. Offshore Pacific Production and Drilling Forecast

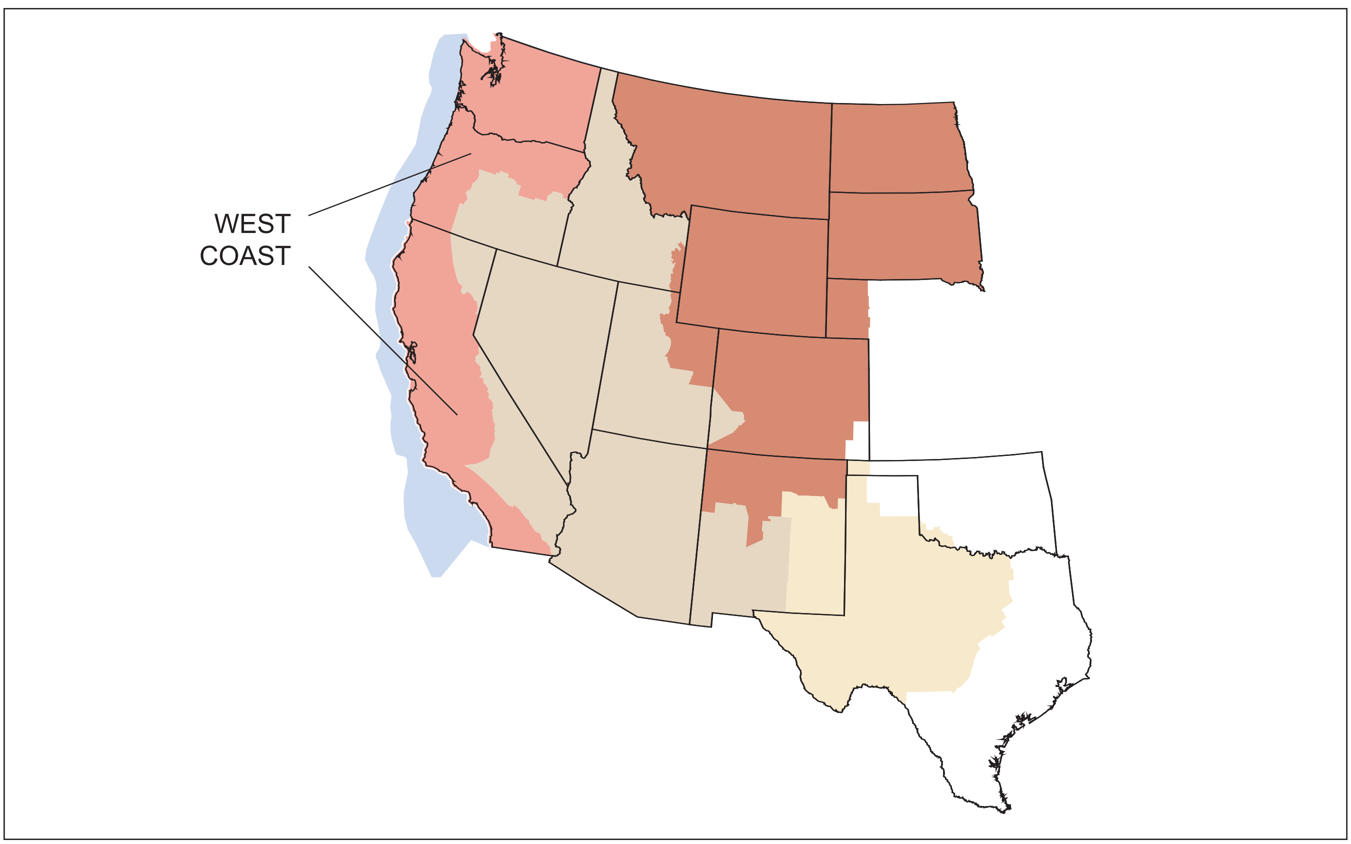


Figure S2-29. Location of the West Coast Super-Region

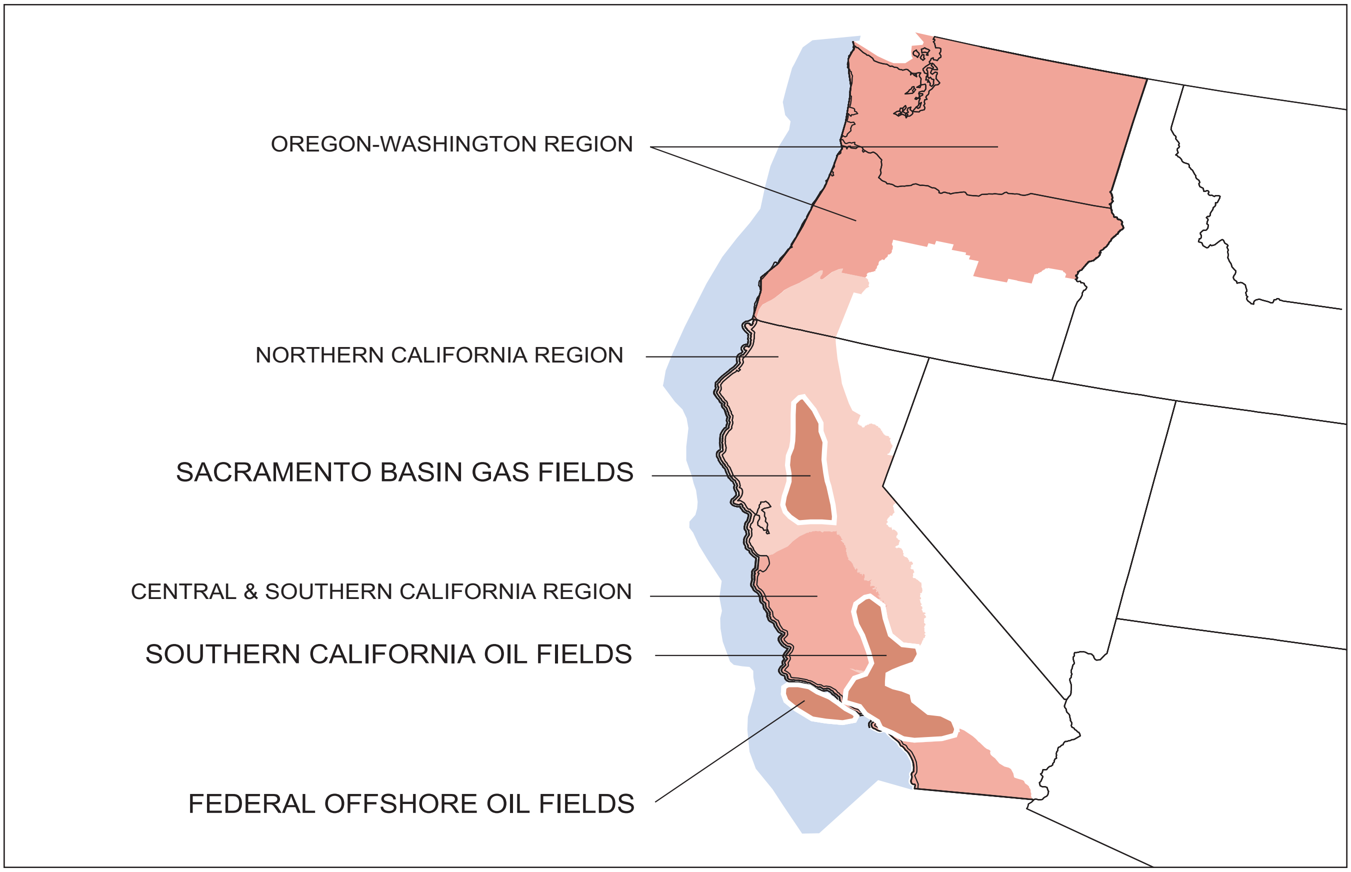


Fig. S2-30. West Coast Onshore Regions and Major Producing Areas

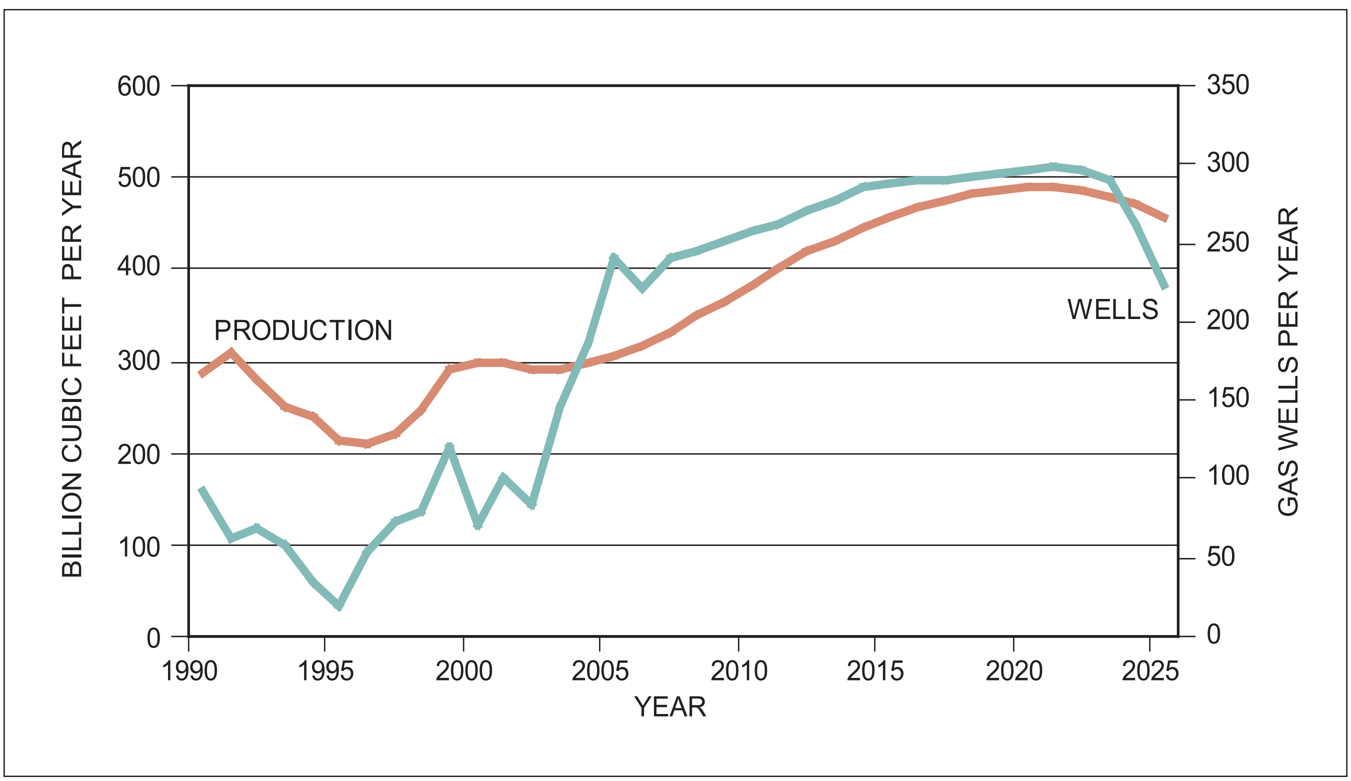


Figure S2-31. West Coast Onshore Production and Drilling Forecast

b. Growth of Existing Fields

The West Coast has produced 31.9 TCF to date. The total future growth in the conventional oil and gas fields is estimated to be 3.2 TCF.

c. Undiscovered Fields Background Studies

Assessments by the USGS were used as the basis for the assessment of the West Coast. The USGS did an assessment of the entire onshore U.S. in 1995 (http://energy.cr.usgs.gov/oilgas /noga/index.htm).

The NPC conducted workshops for major undiscovered gas regions. No workshop was held for this area because of minimal activity since 1995. The USGS 1995 assessment was adopted without change for this super-region.

d. Undiscovered Fields Results for the West Coast Super-Region

The NPC accepted without change the USGS assessment, resulting in an assessment of 23.3 TCF of undiscovered potential including small fields. Forty-five percent of this resource is in a nonconventional tight sandstone play located in the Columbia Basin of Eastern Oregon-Washington. This gas underlies the Miocene Columbia River Basalt which has a thickness of over 5,000 feet (Johnson and others, 1997). The economic viability of this play is uncertain. Con-ventional accumulations account for fifty-two percent of the undiscovered gas.

3. References

Johnson, S. Y. and others, 1997. Petroleum Geology of the State of Washington. United States Geological Survey Professional Paper 1582: 40 p.

D. Great Basin Super-Region

1. Super-Region Summary

The Great Basin super-region covers all or most of Nevada, Idaho, Utah, and Arizona (Figure S2-32) and has only minor hydrocarbon production and undiscovered gas compared to other super-regions. With the exception of the Paradox Basin, the basins within the Great Basin super-region contain less than 10,000 feet of sedimentary rocks (Baars and others, 1988). This is generally insufficient to generate significant volumes of hydrocarbons, even if good quality source rocks are present. Total remaining technical resource is 4.7 TCF and cumulative production has been 1.4 TCF.

The USGS 1995 resource assessments are the basis for the NPC's Great Basin assessment. The NPC total undiscovered gas is 3 TCF, which is primarily in the Paradox Basin of southeast Utah (Figure S2-33).

Figure S2-34 shows that historical Great Basin production has been 30-40 BCF/year and 10-20 gas wells/year have been drilled. The Reactive Path outlook is for steadily increasing production and drilling through 2025.

2. Great Basin Assessment Description

a. Remaining Gas Reserves

There is 1.0 TCF of remaining proved gas reserves in the Great Basin.

b. Growth of Existing Fields

Most of the producing fields in the Great Basin are located in the Paradox Basin with a few fields from Nevada. These fields have produced a total of 1.4 TCF to date. The total future growth in the conventional oil and gas fields is estimated to be 1.0 TCF.

c. Undiscovered Fields Background Studies

Assessments by the USGS were used as the basis for the assessment of the Great Basin. The USGS did an assessment of the entire onshore U.S. in 1995 (http://energy.cr.usgs.gov/oilgas/noga/index.htm).

The NPC conducted workshops for major undiscovered gas regions. The Great Basin is a minor super-region, so no workshop was conducted for this area. The USGS 1995 assessment was adopted without change for this super-region.

d. Undiscovered Fields Results for the Great Basin Super-Region

The undiscovered gas in the Great Basin has been assessed by 31 USGS-defined plays (Gautier and others, 1996). Only one of the 31 plays is a nonconventional play. The NPC 2003 accepted without change the USGS 1995 assessment of 3.0 TCF for this super-region. The Paradox Basin, located mostly in southeast Utah, accounts for over 70% of undiscovered gas within the Great Basin super-region.

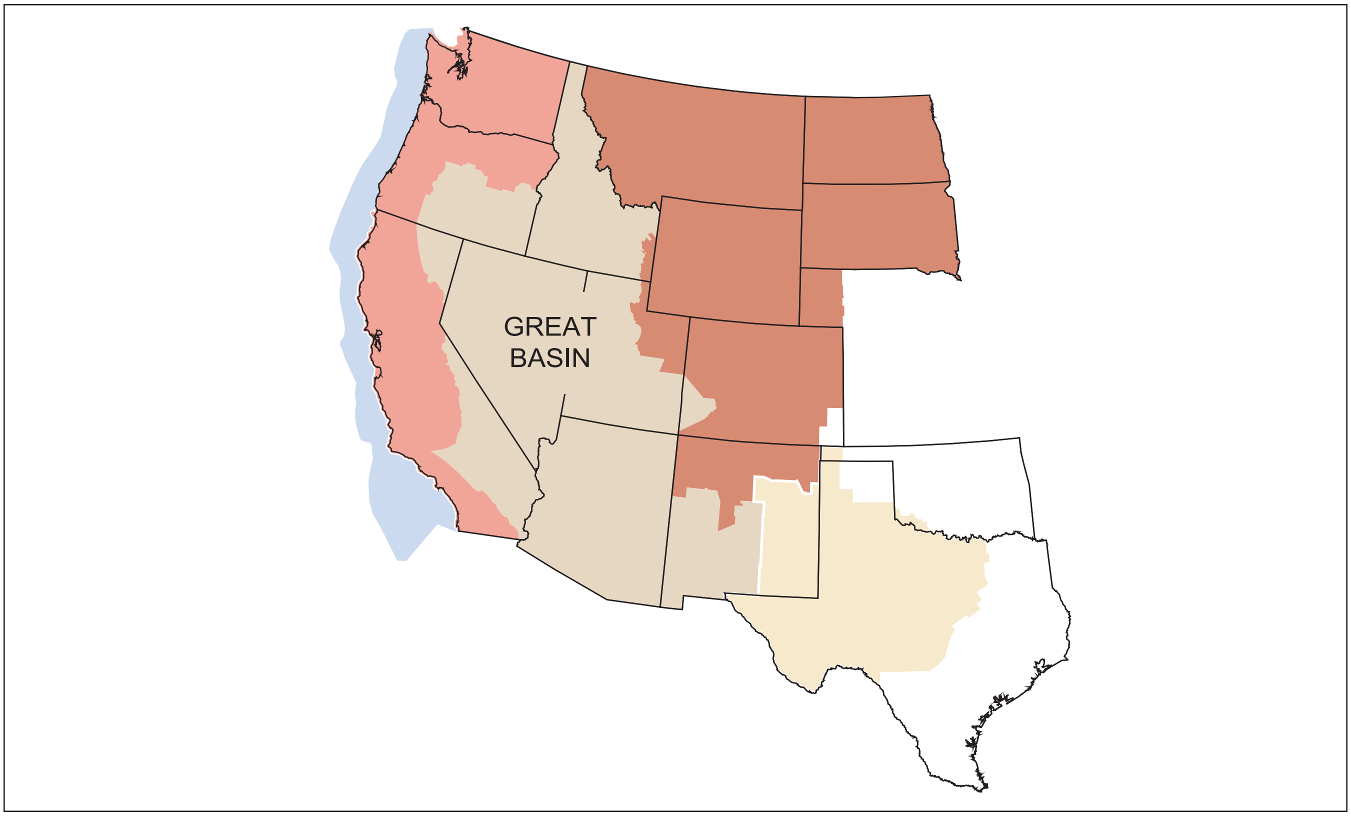


Figure S2-32. Location of the Great Basin Super-Region

Figure S2-33. Location of Paradox Basin Region within the Great Basin Super-Region

3. References

Baars, F. L. and others, 1988. Basins of the Rocky Mountain Region. p. 109-220. *in* L. L. Sloss (ed), Sedimentary Cover - North American Craton. The Geology of North America vol. D-2. Geological Society America (Boulder, Colorado); 506 p.

E. Rockies Super-Region

1. Super-Region Summary

The Rockies super-region covers several western states (Figure S2-35) and is made up of eleven NPC regions: San Juan, Raton, Denver, Uinta-Piceance, Southwest Wyoming, Wyoming Thrust, Wind River, Big Horn, Powder River, Montana Thrust, and Williston/Northern Great Plains (Figure S2-36). The Rockies is an important gas producing super-region and also one of the largest sources of undiscovered gas. Total remaining technical resource is 284.1 TCF and cumulative production has been 67.1 TCF.

The USGS 1995/2002 resource assessments are the basis for the NPC's Rockies assessment. The NPC total undiscovered gas is 209 TCF which is 41 TCF lower

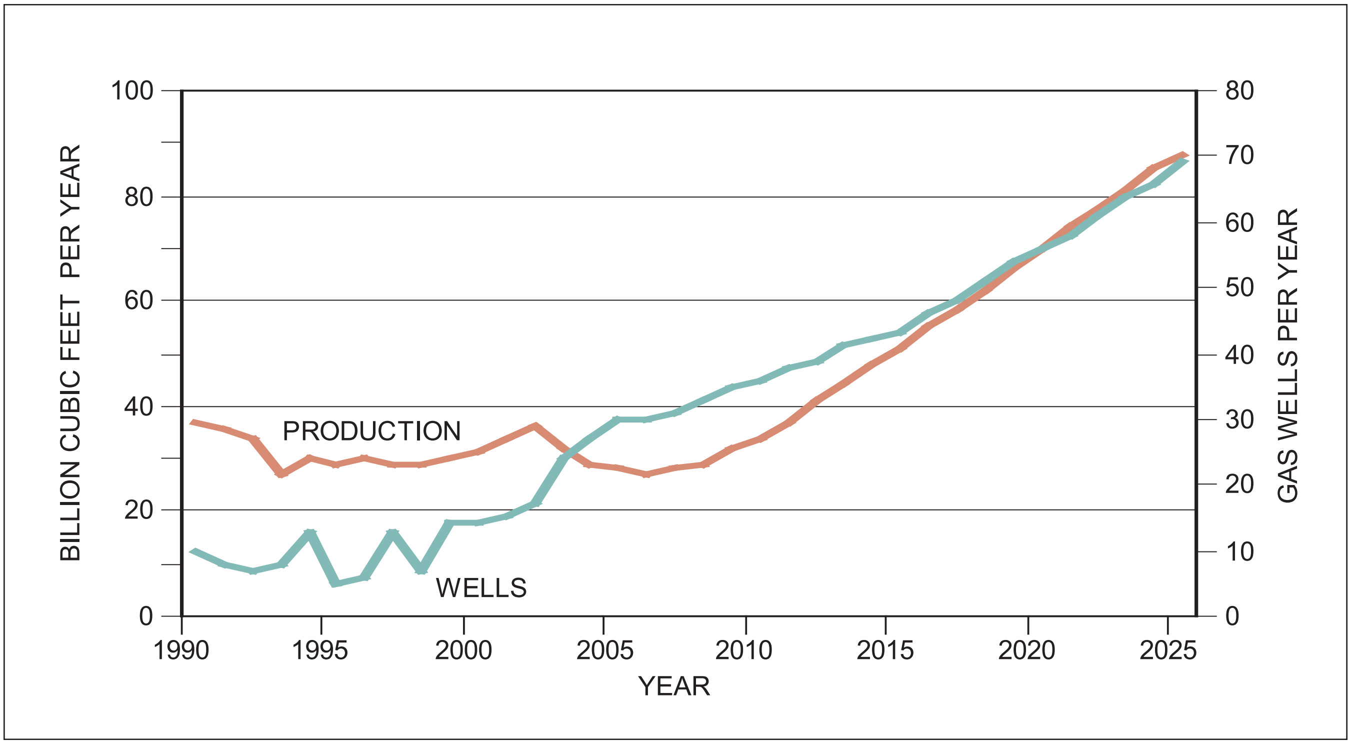


Figure S2-34. Great Basin Production and Drilling Forecast

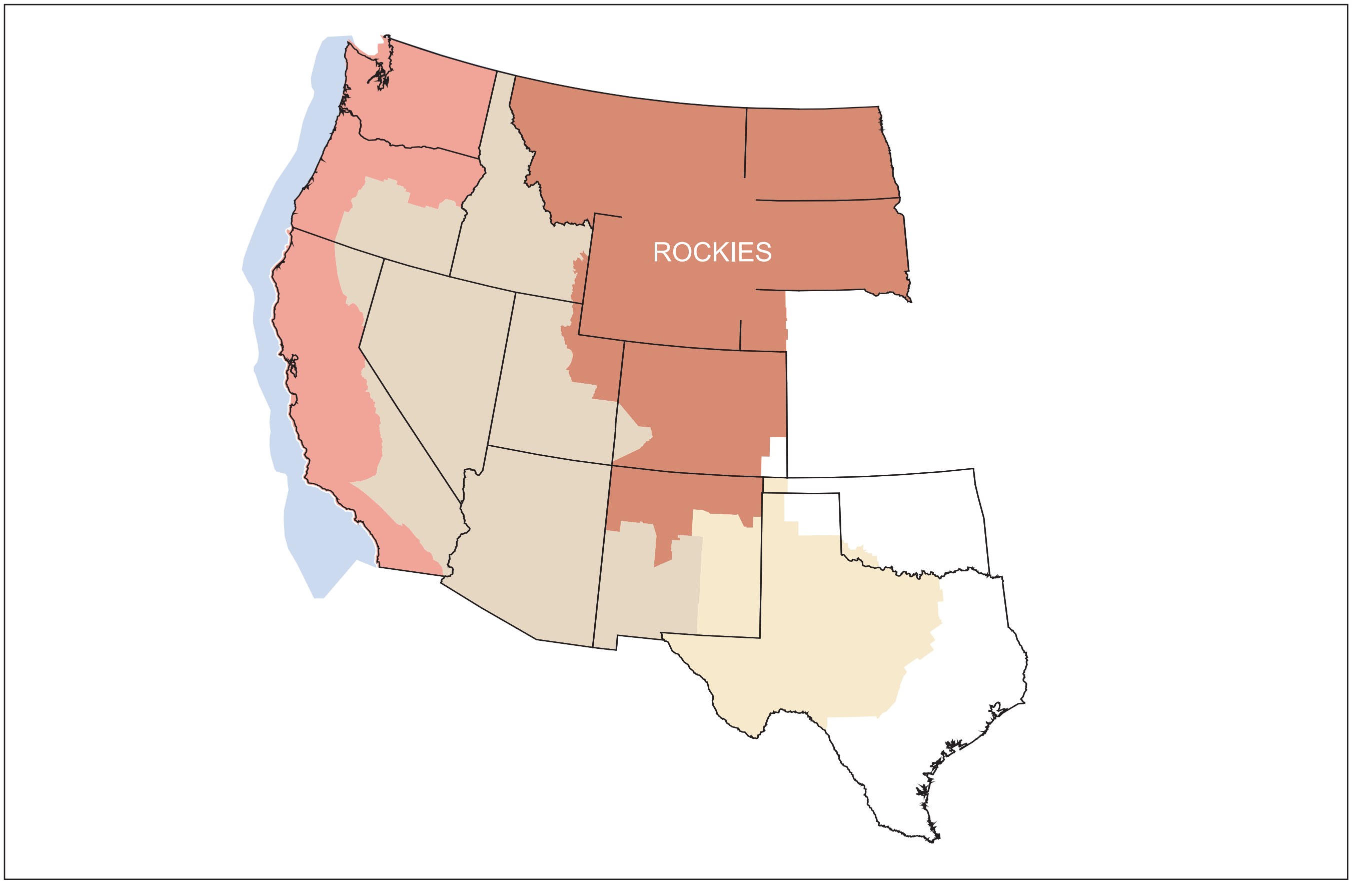


Figure S2-35. Location of the Rockies Super-Region

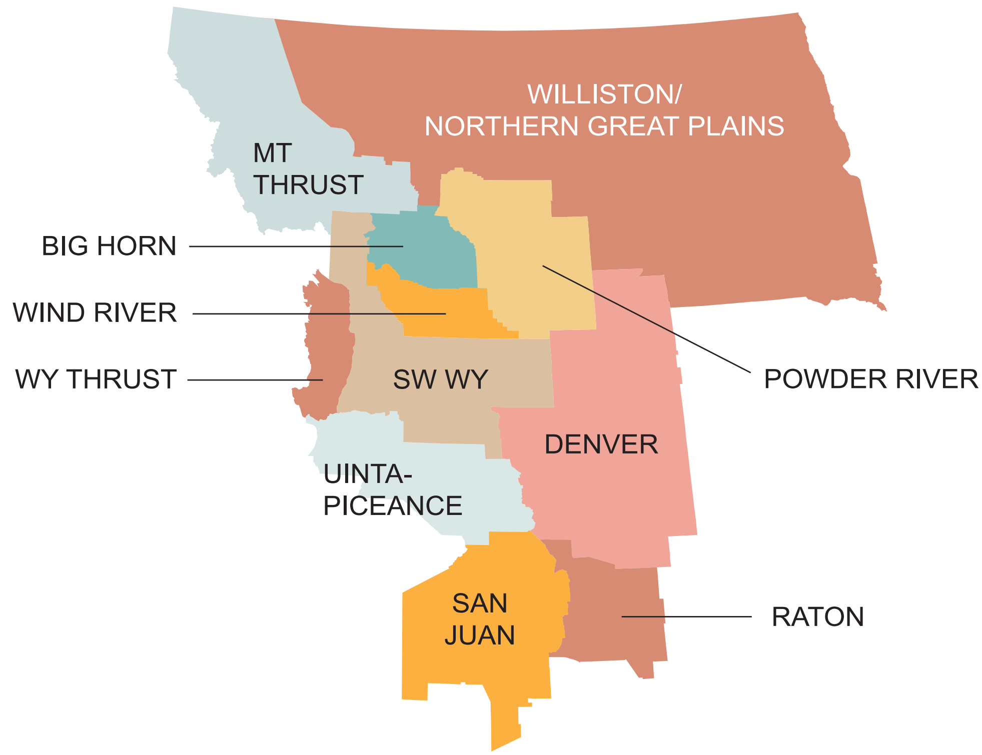


Figure S2-36. Rockies Regions

than the most recent USGS assessment (Table S2-3). Most of the Rockies undiscovered gas (80%) is in nonconventional plays such as coal bed methane and tight gas.

Several nonconventional plays have been extensively developed in recent years including coal bed methane in the San Juan, Powder River, and Raton basins. Most of the large potential volumes of tight gas in the Southwest Wyoming, Uinta-Piceance, and San Juan regions have yet to be economically developed at a large scale.

The Rockies super-region has significant access issues related to U.S. government land stipulations as well as other government regulations. These issues will impact future gas production rates in this super-region.

In the Reactive Path outlook, today's production of around 3 TCF/year will climb to almost 5 TCF/year by 2020 (Figure S2-37). Drilling activity is expected to be 4,000 to 6,000 gas wells/year, which is a similar level to the 2000-2001 peak.

NPC Region	USGS 1995/2002 (TCF)	NPC 2003 (TCF)
San Juan	50.6	30.1
Raton	1.8	2.0
Denver	3.9	3.7
Uinta-Piceance*	21.4	30.8
Southwest Wyoming*	84.6	87.0
Wyoming Thrust	12.0	12.0
Wind River	1.7	2.0
Big Horn	0.6	0.4
Powder River*	16.5	21.7
Montana Thrust*	8.6	8.3
Williston/Northern Great Plains	45.8	11.1
Total	**247.6**	**208.9**

*USGS 2002 Assessments

Table S2-3. Rockies Regions Undiscovered Gas – Comparison of NPC and USGS

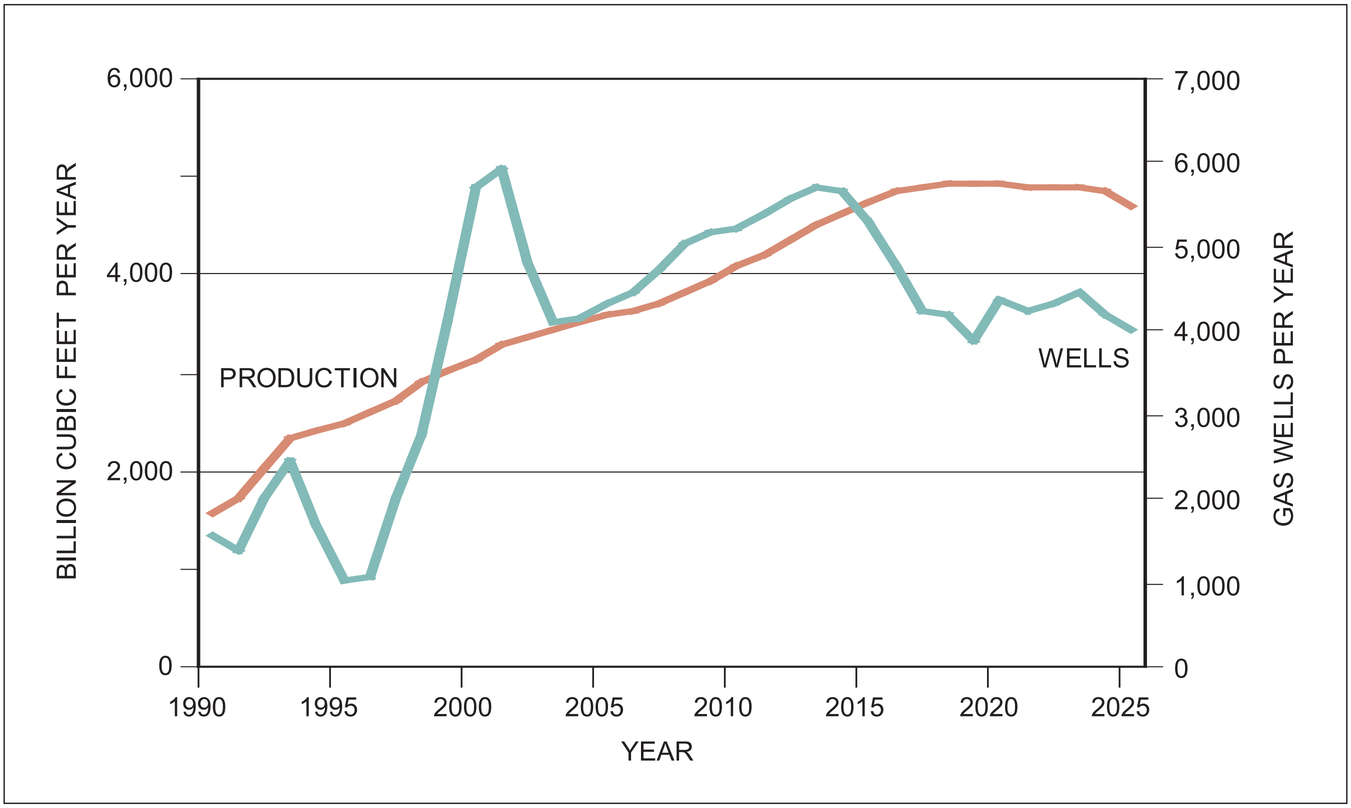


Figure S2-37. Rockies Production and Drilling Forecast

2. Rockies Exploration History

Gas exploration in the Rockies played a secondary role to oil exploration from the first oil discovery until the late 1970s. Gas associated with early oil production was often vented or locally used. In 1862, the first oil was discovered by a well drilled near a live oil seep in Canon City, Colorado on the west side of the Denver Basin. During the late 1800s several other oil field discoveries near oil seeps were also made in several Rocky Mountain Basins.

In the early 1900s to the 1930s many very large oil and gas fields were discovered in the Big Horn Basin, Wind River Basin, Powder River Basin, Piceance Basin, and in the Northern Great Plains of Montana primarily by drilling of surface anticlines. Oil was still the primary objective for exploration but natural gas started to play a modest role in local areas. In 1924 gas was discovered at Baxter Basin Field, in Southwest Wyoming. A pipeline from this field to Salt Lake City, Utah was built to market the gas.

During the 1940 and 1950s seismic was used to target subsurface anticlines, structural noses, and fault traps. Oil exploration still dominated but many new fields had significant volumes of associated gas that was used locally.

Exploration from 1950-1970s saw the discovery and development of numerous stratigraphic traps in addition to seismically defined anticlinal structures. In the early 1950's a gas pipeline was built from the San Juan Basin to California by El Paso Natural Gas. The demand from the California market resulted in a marked increase in gas well development drilling in the stratigraphic traps of the San Juan Basin. Hundreds of development wells were drilled in the central basin. Similarly, in 1956 a gas pipeline was built from Southwest Wyoming to the Pacific Northwest. This pipeline provided an outlet for gas discovered on the La Barge Platform in the Green River Basin, Wyoming. From the late 1950s to the mid 1960s gas fields were being discovered in the Piceance and Uinta Basins, but full development of these fields did not occur until the 1990s due to low prices, remote locations, and pipeline constraints.

In the late 1970s and into the 1990s gas exploration was driven by higher gas prices, more pipelines and improved technology in well completions and seismic. During this period many previously discovered gas fields were being developed in the Green River Basin, Denver Basin, San Juan Basin, Northern Great Plains of Montana, Piceance Basin, and Uinta Basin. Prior to the 1980s Rockies gas production experienced constraints on sales due to limited pipeline capacity, remote geographic location of many gas fields, rough topography, and long distances to markets. However by the early 1980s more gas pipelines were being built to move gas to eastern and western markets.

The late 1980s and 1990s saw the emergence of coal bed methane (CBM) as a viable source of gas in the Rockies. The San Juan Basin was the first major CBM province and much of this early activity was stimulated by Federal tax credits. By the mid 1990s, however, it became apparent that other CBM plays could be economic without the expired tax credits. Several CBM plays emerged in the Uinta, Raton, and Powder River Basins, in addition to the continued development of the prolific San Juan Basin. Tight gas sand development in the Green River, Wind River, Piceance, Uinta, and Denver Basins has now emerged as the next major development phase in the Rockies.

3. Rockies Assessment Description

a. Remaining Gas Reserves

There are 49.7 TCF of remaining proved gas reserves in the Rockies.

b. Growth of Existing Fields

The Rockies have produced a total of 67.1 TCF to date. The total future growth in the conventional oil and gas fields is estimated to be 25.5 TCF. Nonconventional plays as assessed do not have future growth.

c. Undiscovered Fields Background Studies

Assessments by the USGS were used as the basis for NPC's assessment of the Rockies. The USGS did an assessment of the entire onshore U.S. in 1995 (http://energy.cr.usgs.gov/oilgas/noga/index.htm). In addition, the USGS published updated assessments for the following basins in 2002-2003: San Juan, Uinta-Piceance, Southwest Wyoming, Powder River, Montana Thrust, and Denver (http://energy.cr.usgs.gov/oilgas/noga/index.htm).

The NPC methodology was to assemble industry and government Rockies experts and to hold three workshops to validate and change, if necessary, the mean resource estimates for key large plays. These workshops were held in Houston at the Anadarko Petroleum and ExxonMobil offices and the USGS office in Denver, Colorado.

d. Undiscovered Fields Results for the Rockies Super-Region

The undiscovered gas in the Rockies has been assessed by 169 USGS-defined plays and assessment units (Gautier and others, 1996; Flores and others, 2002; Kirschbaum 2002a, 2002b; Ridgley and others, 2002; Schenk and others, 2002). Twenty-eight (28) of the plays/assessment units defined by the USGS have not been quantitatively assessed. Seventy (70) of the 169 plays/assessment units represent nonconventional plays. Cretaceous and early Tertiary sandstones and coals are the primary reservoirs for undiscovered gas volumes.

Hydrocarbon plays with undiscovered gas greater than 5 TCF were examined in detail by the NPC Supply Task Group. During 2002, the USGS published reassessments of the Uinta-Piceance Basins (Kirschbaum and others, 2002a), Southwestern Wyoming Province (Kirschbaum and others, 2002b), Powder River Basin (Flores and others, 2002), San Juan Basin (Ridgley and others, 2002), and Montana Thrust Belt (Schenk and others, 2002). One additional reassessment of the Denver Basin was published in 2003 (Higley and others, 2003) but is not included in this analysis. These assessments included revision of the USGS 1995-defined hydrocarbon plays into a series of Total Petroleum Systems and accompanying Assessment Units. Assessment Units with greater than 5 TCF gas potential were evaluated in the same manner as the 1995 plays. The 1995 plays were correlated with the 2003 assessment units to avoid double counting. Three workshops were held during late 2002 and early 2003 to which industry, government, and academic experts were invited to evaluate and change, if necessary, the mean resource estimates for these key large plays.

The NPC's 2003 assessment for the Rockies super-region shows a decrease of 41 TCF relative to the USGS 1995/2002 (using USGS 2002 where available as the standard of reference). Primary differences between the NPC 2003 assessment and the USGS revolve around five basins/provinces (Table S2-3). Significant decreases in the undiscovered gas resource involve the North-Central Montana (34.5 TCF decrease) and the San Juan Basin (20.2 TCF decrease). On the other hand, the Powder River (5.7 TCF increase) and Uinta-Piceance Basins (10.3 TCF increase) had NPC increases compared to the USGS. A more detailed discussion of these five basins is presented below.

i. San Juan Basin Region Summary

The San Juan Basin is located in northwestern New Mexico and southwestern Colorado. The basin is approximately 7,500 square miles in size and includes parts of the Navajo, Southern Ute, and Jicarilla Apache Indian reservations (Fasset and Hinds, 1971). The Cretaceous Dakota Sandstone, Mesaverde Group, and Pictured Cliffs Sandstone are the most important gas-producing zones in the basin (Fassett, 1991). The Blanco/Basin Field area, the second largest gas field in the lower-48 states with an estimated ultimate recovery of 23 TCF, produces gas from each of the above stratigraphic units. Coal bed methane production is primarily from the Upper Cretaceous Fruitland Formation coal beds.

The NPC has estimated undiscovered gas at 30.1 TCF. Conventional undiscovered gas accumulations (0.8 TCF) represent only 3% of the undiscovered gas resource. Nonconventional low permeability sandstones represent 52% of the undiscovered gas resource. Coal bed methane from the Fruitland Formation comprises 29% of the undiscovered gas resource.

The NPC estimate is a 20.5 TCF decrease from the USGS 2002 estimate (Ridgley and others, 2002). This decrease is due to a reduction in both play area and average expected gas recovery per undrilled location ("cell") for the Basin Fruitland Assessment Unit and the Lewis Gas Assessment Unit. This in turn is based on updated well performance histories and additional exploratory drilling results provided by San Juan Basin operators and experts. The decrease is 15.3 TCF and 5.2 TCF for the Basin Fruitland Assessment Unit and Lewis Gas Assessment Unit, respectively.

ii. Powder River Basin Region Summary

The Powder River Basin, located in northeastern Wyoming and southeastern Montana, is the largest intermontane basin in the northern portion of the Rocky Mountains. The basin is notable for being the fifth largest producer of coal resources in the world and production in excess of 2.5 million pounds of uranium oxide (Baars and others, 1988). Conventional gas production is predominantly from Pennsylvanian, Permian, and Cretaceous sandstone reservoirs. Coal bed methane production is primarily from upper Cretaceous-Paleocene Fort Union and Eocene Wasatch formations.

The NPC has estimated undiscovered gas at 21.7 TCF. Conventional undiscovered gas accumulations (1.5 TCF) represent approximately 7% of the undiscovered gas resource. Coal bed methane comprises 88% of the undiscovered gas resource.

The NPC estimate is a 5.2 TCF increase from the USGS 2002 estimate (Flores and others, 2002). This increase is due to updated well performance histories provided by Powder River Basin operators and experts. An increase of 5.2 TCF for the Fort Union Assessment Unit accounts for the total basin increase. A recent assessment of undiscovered coal bed methane in the Powder River Basin conducted by Advanced Resources International (ARI) for the U.S. Department of Energy estimated 39 TCF of undiscovered recoverable coal bed methane. This is nearly twice the NPC 2003 estimate (Advanced Resources International, 2002). ARI based their estimate on reservoir simulation of over 1,000 wells, recognition of free gas and higher gas content assumptions for certain Powder River Basin coals and new data on the Wasatch coals along the western edge of the basin. The NPC 2003 used the same methodology as the USGS to estimate undiscovered coal bed methane but used slightly more optimistic input parameters. This methodology does not include any reservoir simulation modeling, but relies on historical well decline analysis.

iii. Southwest Wyoming Region Summary

The Southwest Wyoming Region (Greater Green River Basin) is located in southwestern Wyoming and adjacent portions of Colorado and Utah. The province is comprised of four sedimentary basins (Great Divide, Green River, Sand Wash, and Washakie) and four intrabasin uplifts (Wamsutter Arch, Cherokee Arch, Moxa Arch, and Rock Springs Uplift). Gas production is primarily from Late Cretaceous-early Tertiary sandstones.

The NPC has estimated undiscovered gas at 87 TCF. Conventional undiscovered gas accumulations represent 5% of the undiscovered gas resource. Coal bed methane from the Mesaverde, Lance-Ft. Union and Wasatch-Green River Formations represents 2% of the undiscovered gas resource. Nonconventional low-permeability sandstones and low BTU gas from the Moxa Arch comprise the other 93% of the undiscovered gas resource. The NPC nonconventional tight gas assessment is substantially lower than the USGS assessment (65.8 TCF vs. 80.6 TCF).

The NPC total basin assessment is similar to the USGS 2002 assessment (Kirschbaum and others, 2002b) but some of the individual plays differ. Plays that decrease are due to a reduction in both play area and the average chance of success for undrilled locations ("cells") for the Rock Springs-Ericson assessment unit and the Lewis Gas assessment unit. This, in turn, is based on updated well performance histories and additional exploratory drilling results provided by Southwest Wyoming operators and experts. The decrease is 6.1 TCF and 6.8 TCF for the Rock Springs-Ericson assessment unit and Lewis Gas assessment unit, respectively. This is partially offset by a 0.5 TCF increase in the Mesaverde CBM and 2.3 TCF increase of conventional resources due to adding the small field fraction.

In addition, the NPC added 14.5 TCF of low BTU gas which the USGS did not include in their assessment. This low BTU gas is contained within the Madison Formation on the Moxa Arch and is only about 22% methane (Vidas and others, 2003). The 14.5 TCF is the recoverable methane portion of the accumulation. It should be noted that there are multiple definitions for low BTU gas. The American Gas Association (AGA) definition is gas with a heating value of less than 250 BTU per standard cubic feet of raw gas. This Moxa Arch gas would fit that definition.

Subquality gas (Springer and others, 1999) has greater than 4% nitrogen or 2% carbon dioxide or 4 ppm hydrogen sulfide. Under this definition the gas has to undergo some processing before it can be put into a pipeline for sale. This is different than the low BTU gas of the AGA definition. About 40% of U.S. gas reserves are low quality (Springer and others, 1999).

A recent study of the Greater Green River Basin (same area as Southwest Wyoming NPC region) by Boswell and others (2002) under contract to DOE resulted in an undiscovered technically recoverable gas estimate of 363 TCF. This study used a large number of wells, estimates of volumetric parameters from well log analysis, detailed well log correlation grid and estimates of reservoir engineering parameters to estimate gas-in-place and technically recoverable gas. This estimate is about four times larger than the NPC 2003 assessment of undiscovered gas for this area. This estimate was relating to basin-centered tight gas resources. The methodology used in the DOE study was fundamentally different than that employed by the USGS. The USGS outlines a play area for the basin-centered gas play, determines the well spacing that an average well could effectively drain, determines the number of untested spacing units (cells) within the play outline, estimates the average gas recovery per well (or cell), and estimates a success factor for wells drilled within the outline. Multiplying the number of untested cells by the average gas recovery and success factor gives the mean recoverable gas for that play. The DOE methodology first calculates gas in place in the basin-centered gas play. This is done by outlining a play area and determining a depth or pressure regime below which all sands within the play are assumed to be gas bearing. Well logs from existing wells are used to calculate thickness, average porosity, and gas saturation of the sands within the play. These parameters are used to make a volumetric calculation of gas in place for the play. Reservoir engineering data is then employed to estimate how much of this gas is potentially technically recoverable. This approach usually gives much larger values for recoverable gas than the USGS method. The issue with this method is that well logs can not readily distinguish between gas and water bearing zones in low permeability (tight) sands. Therefore, some of the sands that are "counted" as containing gas in this method may actually contain water.

iv. Uinta-Piceance Basin Summary

The Uinta and Piceance basins are closely associated structural and sedimentary basins located in northeastern Utah and northwestern Colorado, respectively. The basins cover an area of approximately 40,000 square miles and are separated from each other by the north-south trending Douglas Creek Arch. Gas production is primarily from Cretaceous and Tertiary sandstones.

The NPC has estimated undiscovered gas at 30.8 TCF. Conventional undiscovered gas accumulations represent 14% and coal bed methane from Cretaceous formations 17% of the undiscovered gas resource. Nonconventional low-permeability sandstones comprise 69% of the undiscovered gas resource.

The NPC estimate is a 9.4 TCF increase from the USGS 2002 estimate (Kirschbaum and others, 2002). This change is due to additional drilling in the basins resulting in an increase in the number of untested coal bed methane undrilled locations ("cells").

v. Williston/Northern Great Plains Region Summary

Beginning in the 1970s and continuing through the present, the United States Geological Survey has conducted geological studies to characterize and estimate the gas potential of low-permeability reservoirs in the Rocky Mountains (Spencer and others, 1977; Rice and Shurr, 1980; Gautier and others, 1995; Condon, 2000). These studies identified the potential for undiscovered gas in Cretaceous low-permeability sandstones derived from bacterial processes ("biogenic gas") at relatively shallow depths (<1,200 meters). The USGS 1995 estimate was 41.8 TCF for this play (Gautier and others, 1996). The USGS 1995 assessment for all plays in this region is 45.8 TCF.

The NPC 2003 estimate of 11.1 TCF is a 34.7 TCF decrease from the USGS 1995 estimate. This reduction is based on relatively unsuccessful exploratory drilling during the last decade which has significantly reduced the area of potential production.

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F. West Texas Super-Region

1. Super-Region Summary

The USGS 1995 assessment provides the basis for the NPC's assessment of the West Texas super-region (Figure S2-38), which includes five USGS provinces in West Texas and New Mexico: Pedernal Uplift, Palo Duro Basin, Permian Basin, Bend Arch-Fort Worth Basin, and the Marathon Thrust Belt (Figure S2-39). This Super-Region has about 27 TCF of undiscovered gas potential. The NPC focused on the Permian Basin, which had about 60% of USGS undiscovered gas potential. Total technical resource is 64.5 TCF and cumulative production has been 105.4 TCF.

The Permian Basin currently produces about 5 BCF per day. About 40% of this is associated gas, and tight gas accounts for 30%. Production has been flat over the last several years, but increasingly more wells are needed to maintain that production level. There were about 700 completions in 1999 and 1300 in 2001. Initial gas production rate is 800 MCFD in 2001 versus 500 MCFD in 1999. The average decline rate in 2001 is steeper than in prior years.

The Permian Basin is in a very mature stage of exploration and development. In the future, reserve additions will come more from growth to existing fields and less from new field discoveries.

The NPC reduced Permian Basin undiscovered gas potential by 6 TCF compared to the USGS 1995 assessment because of the advanced exploration maturity of

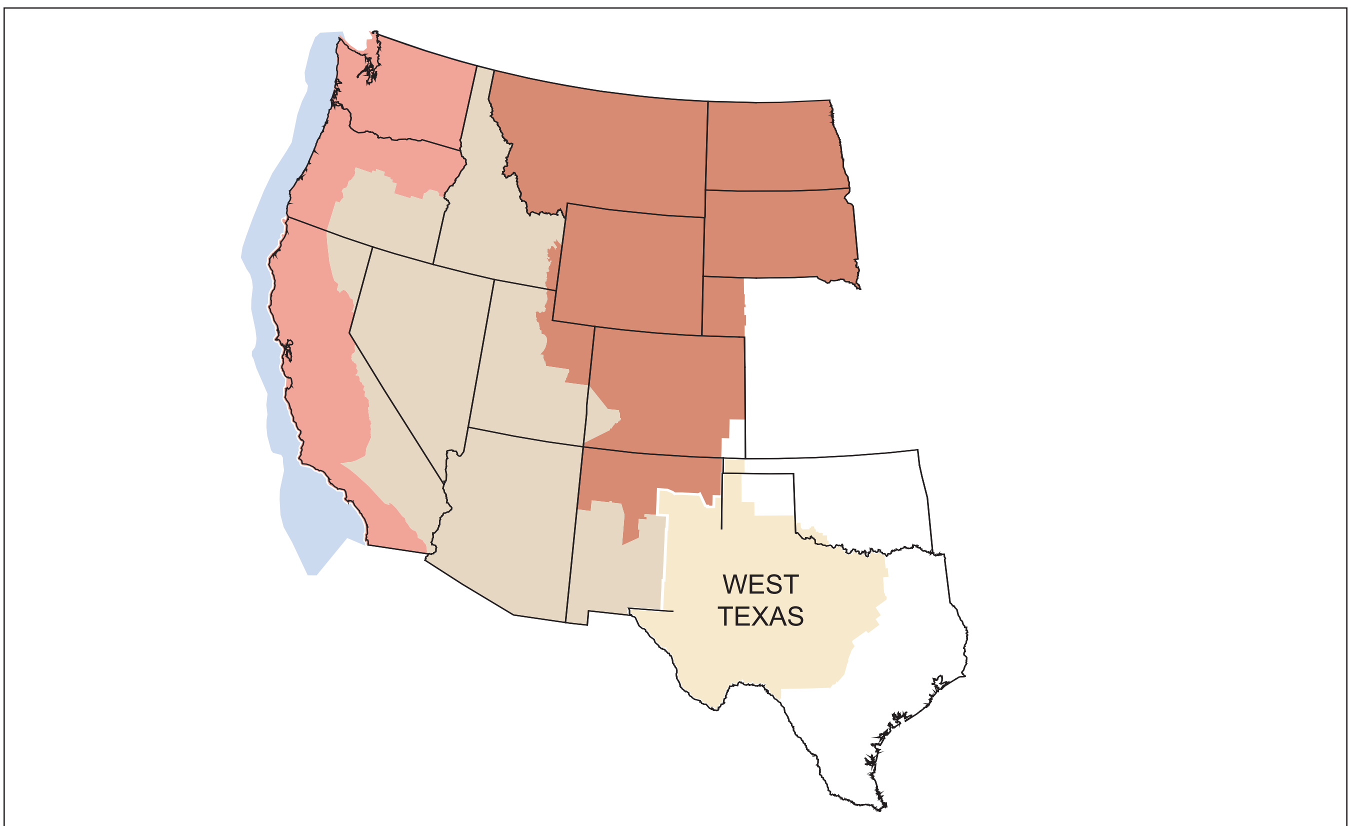

Figure S2-38. Location of the West Texas Super-Region

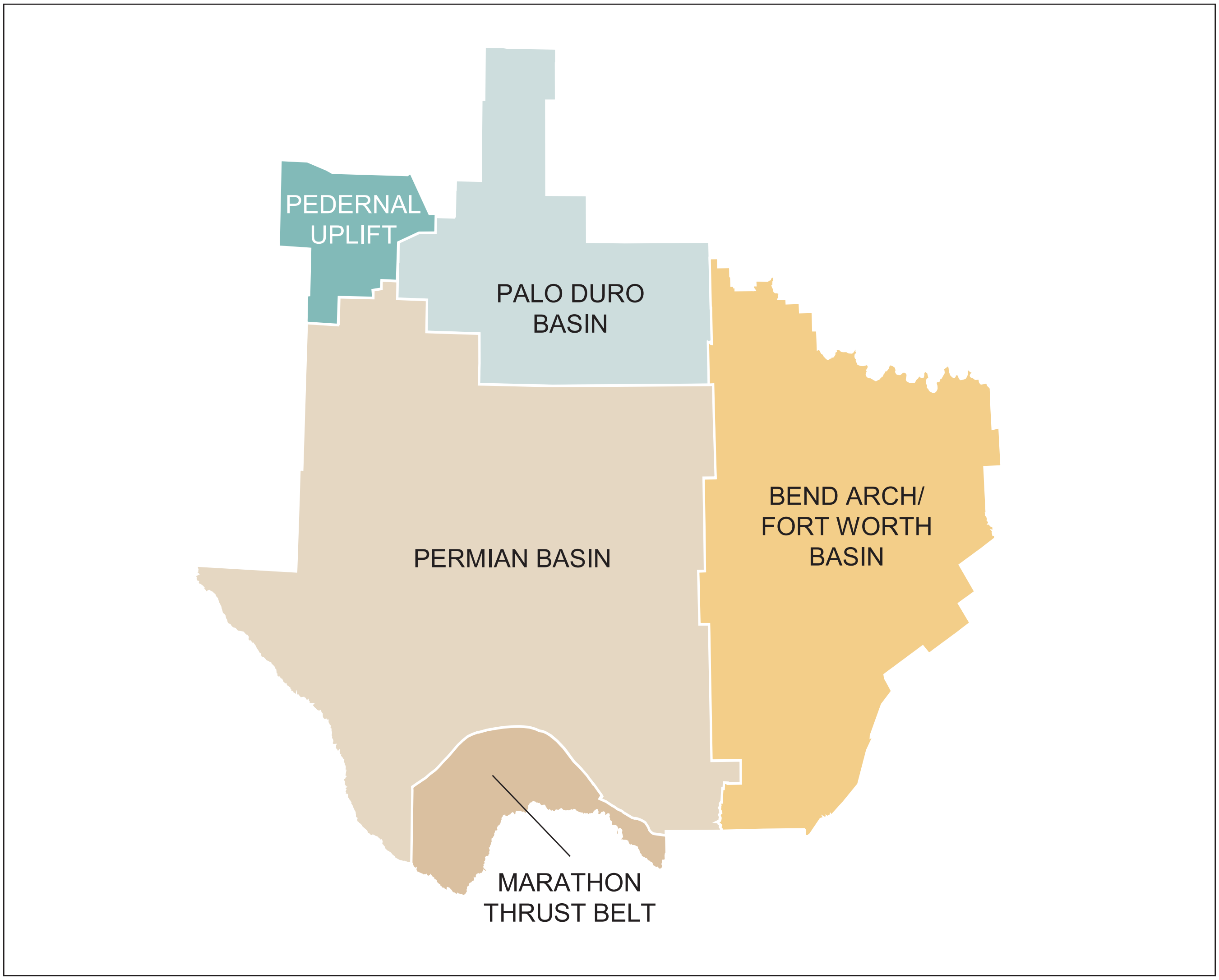

Figure S2-39. West Texas Regions

the basin and the small average size of new field discoveries since 1995.

In the Reactive Path outlook, production declines from today's 1.7 TCF/year to 1.3 TCF/year by 2025 (Figure S2-40). Even with this decline, 800 to 1,200 wells/year will be needed.

2. Permian Basin Assessment Description

a. Remaining Gas Reserves

There are 16.4 TCF of remaining proved gas reserves in West Texas.

b. Growth of Existing Fields

The West Texas fields have produced 105.4 TCF to date. The total future growth in these fields is estimated to be 21.5 TCF.

c. Undiscovered Fields Background Studies

The national assessment made by the USGS in 1995 was used as the basis for the gas potential of the Permian Basin. The USGS identified 12 geologic plays with gas potential, all but one of which is primarily associated gas. The assessment results are documented in USGS Circular 1118 (http://energy.cr.usgs.gov/oilgas/noga/index.htm).

The NPC methodology was to assemble industry, government, and academic experts on the Permian Basin and hold a workshop to validate and change, if necessary, the mean resource estimates for key large plays. This workshop was held at the USGS office in Denver, Colorado.

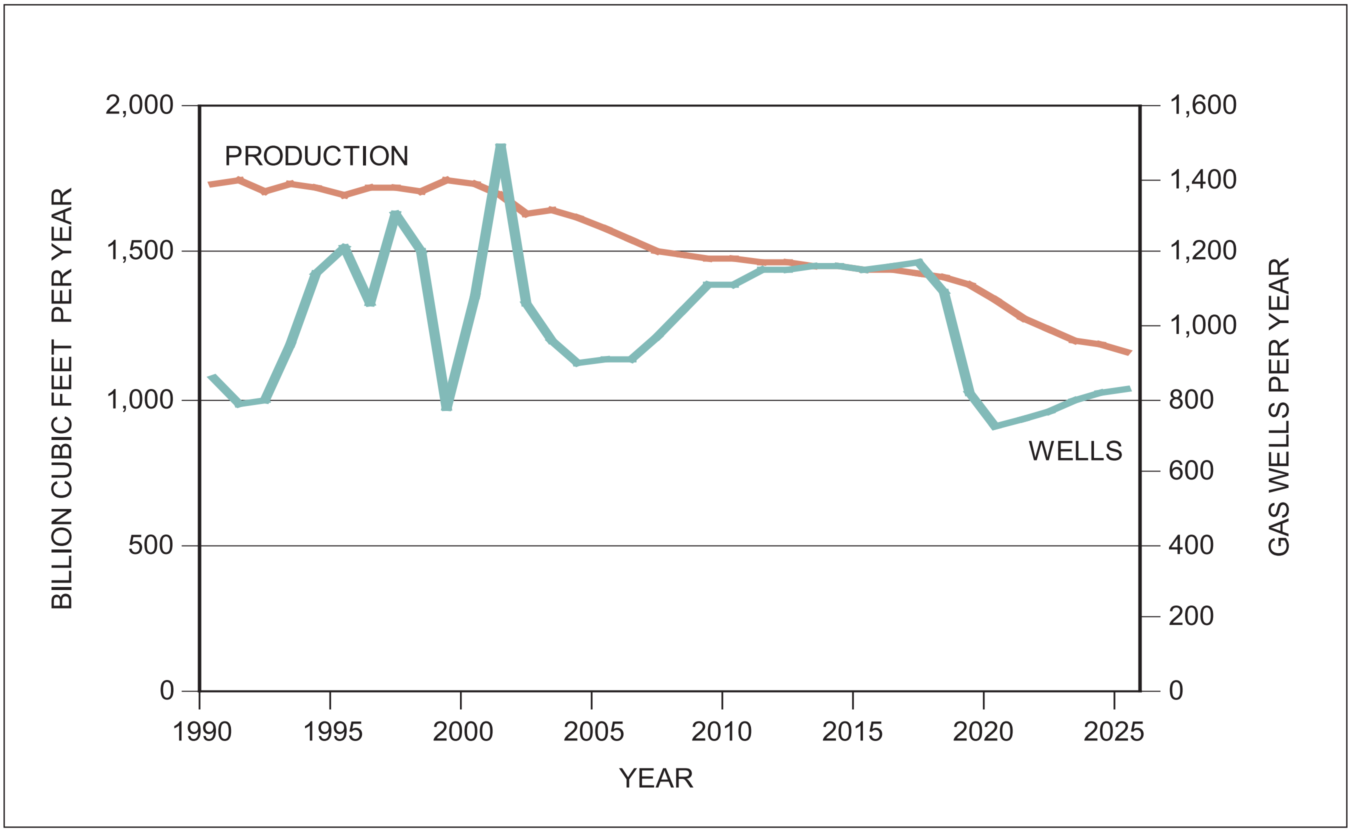

Figure S2-40. West Texas Production and Drilling Forecast

d. Undiscovered Fields Results

The USGS 1995 assessment of undiscovered gas for the Permian Basin is 13.2 TCF in 12 plays. Approximately 75% is non-associated gas.

The NPC examined the 5 largest plays in the Permian Basin which account for about 80% of the undiscovered gas potential. The consensus of the experts was to reduce the assessment of four of the five plays. There was a recognition of large reserve potential related to growth of existing fields which may be greater than that of undiscovered new fields.

The Pre-Pennsylvanian/Delaware-Val Verde play was reduced from 3.9 TCF to 2 TCF. This play is very mature and consensus was that future discoveries will be fewer and smaller than projected in the USGS 1995 assessment. It was noted that growth of existing fields could be significant in this play (2 TCF).

The Lower Pennsylvanian (Bend) Sandstone play was reduced from 3.2 to 1 TCF. There is good potential for finding many new fields but their average size will be very small (5-10 BCF).

The Upper Pennsylvanian and Lower Permian Slope/Basin Sandstone play was reduced from 1.5 to 0.76 TCF because the NPC experts thought the average undiscovered field size should be about 15 BCF (half the size of the USGS 1995 assessment).

The San Andres-Clearfork/Northwestern & Eastern Shelves play was reduced from 1 to 0.3 TCF because the trend has been largely explored and recent discoveries are mostly low volume producers (< 1 BCF per well). Future discoveries will likely continue to be very small.

i. Nonconventional Resources

Tight gas in the Permian Basin is considered to be associated with conventional accumulations. Most tight gas production to date comes from the Canyon Formation.

A possible nonconventional play in the Permian Basin is the Barnett Shale which is being developed in the adjacent Fort Worth Basin. Commercial production has not been developed from this formation in the Permian Basin and no undiscovered gas potential is assessed at this time.

No coal bed methane potential is assessed for the Permian Basin because there are no known coal deposits in the basin.

3. Other West Texas Provinces

The NPC only held a workshop related to the Permian Basin and did not discuss the other USGS provinces which make up the balance of the NPC West Texas Super-region. The future gas resource of these other provinces was small relative to the major North American provinces. The NPC will use the USGS 1995 undiscovered gas for these other provinces except for the Barnett Shale play in the Bend Arch/Fort Worth Basin.

The Bend Arch/Fort Worth Basin is, like the Permian Basin, a mature area for conventional gas. The USGS identified seven plays with gas potential including the continuous Barnett Shale play. This play has been actively developed in recent years. Undiscovered potential in this USGS province is 14.6 TCF of which about half is the nonconventional Barnett Shale (7.0 TCF). The Barnett Shale potential is based on recent work by the USGS.

The Marathon Thrust Belt in southwest Texas has one play and undiscovered potential of 142 BCF. The Palo Duro Basin, located in the Texas panhandle area, has an undiscovered potential of only 3 BCF. The Pedernal Uplift, located in eastern New Mexico, has no undiscovered gas potential.

G. Midcontinent Super-Region

1. Super-Region Summary

The USGS 1995 assessment is the basis for the undiscovered resource of the Midcontinent Super-Region (Figure S2-41), which includes 11 USGS provinces in Oklahoma, Kansas, Missouri, Iowa, Minnesota, and portions of Nebraska, Texas, Arkansas, and Wisconsin. The combined undiscovered gas resource totals about 32 TCF. The Anadarko basin contains 21 TCF or two-thirds of the total. Two other USGS provinces have significant undiscovered gas: the

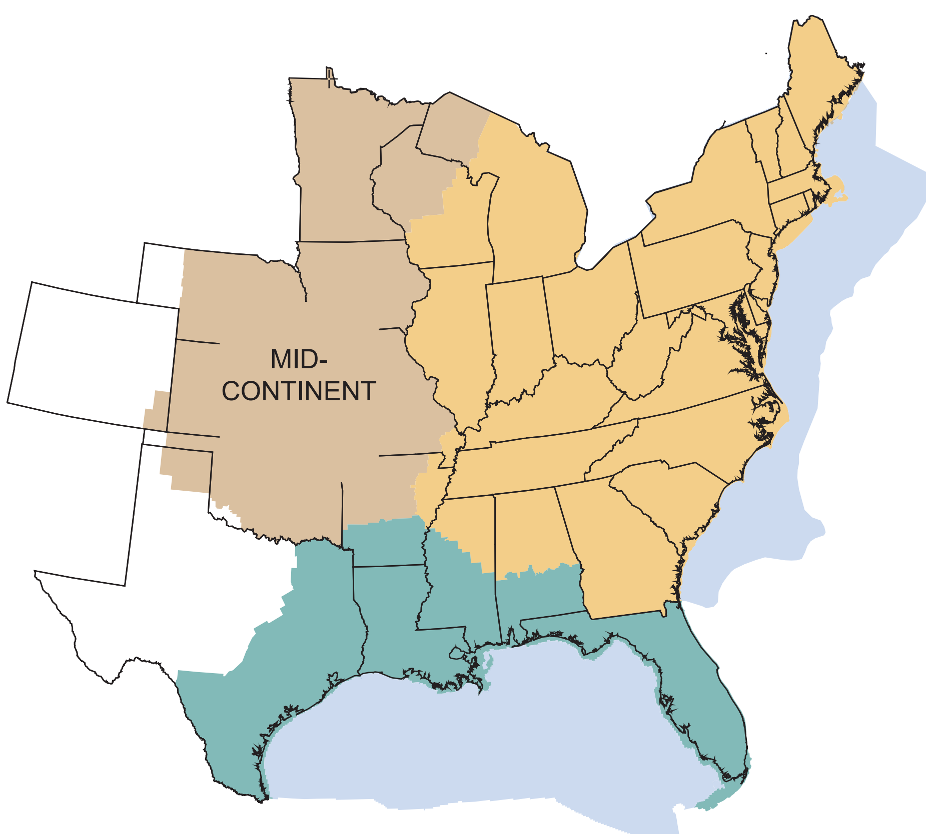

Figure S2-41. Location of the Midcontinent Super-Region

Arkoma basin with about 6.4 TCF and the Cherokee uplift with about 4.4 TCF. The Midcontinent's remaining technical resource is 88.0 TCF and cumulative production has been 179.9 TCF.

Approximately 75% of the super-region's gas resources are in conventional accumulations. The other 25% is mostly coal bed methane in the Arkoma basin, Cherokee uplift and Forest City basin. The Cherokee uplift and Forest City basin are contained within the Northern Midcontinent region (Figure S2-42).

The Anadarko basin currently produces about 5.4 BCF per day with 93% of that coming from gas wells. Tight gas reservoirs account for 10% of current gas production. Production has remained flat over the past several years but more wells per year have been needed to maintain production. There are 100-200 gas completions per month with an average ultimate recovery of 0.6-0.7 BCF. The average ultimate recovery in 1990 was 1.2-1.4 BCF. Current wells also show higher initial rates and steeper decline rates than in the past. Problems with gas production reporting leads to some uncertainty in actual gas production volumes in this basin especially regarding multiple gas purchasers ("split connections").

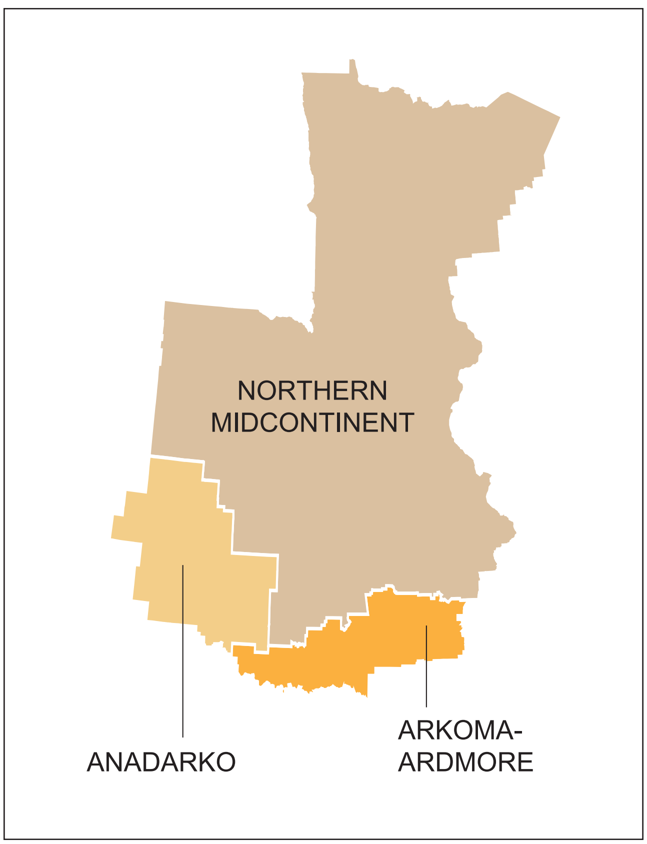

Figure S2-42. Midcontinent Regions

The NPC increased the undiscovered gas resource in the Anadarko basin by 5 TCF due to recent promising discoveries in certain plays. The resource assessment for the other regions within the Midcontinent were not changed from the USGS 1995 assessment.

Although the Midcontinent is the second largest super-region in terms of cumulative gas produced, it has declined rapidly from 1990 to the current level of 2 TCF/year. In the Reactive Path outlook, production will remain relatively flat for the next 10 years and decline slightly thereafter (Figure S2-43). A high level of drilling activity (3,000 to 3,500 wells/year) will be required to maintain this production.

2. Anadarko Basin Assessment Description

a. Remaining Gas Reserves

There are 24.0 TCF of remaining proved gas reserves in the Midcontinent.

b. Growth of Existing Fields

The Midcontinent has produced a total of 179.9 TCF to date. The total future growth in these fields is estimated to be 32.3 TCF.

c. Undiscovered Fields Background Studies

The national assessment made by the USGS in 1995 was used as the basis for the gas potential of the Anadarko Basin. The USGS identified 23 geologic plays with gas potential. These plays are all considered to be "conventional" by USGS definitions. No nonconventional play (tight gas, coal bed methane, shale gas) potential was identified. The assessment results are documented in USGS Circular 1118, which can be found on the internet at http://energy.cr.usgs.gov /oilgas/noga/index.htm.

The NPC methodology was to assemble industry, government, and academic experts on the Anadarko basin and hold a workshop to validate and change, if necessary, the mean resource estimates for key large plays. This workshop was held at the USGS office in Denver, Colorado.

d. Undiscovered Fields Results

The USGS 1995 assessment estimated an undiscovered gas resource of 11.1 TCF in 23 plays in the Anadarko basin. Approximately 86% of this is

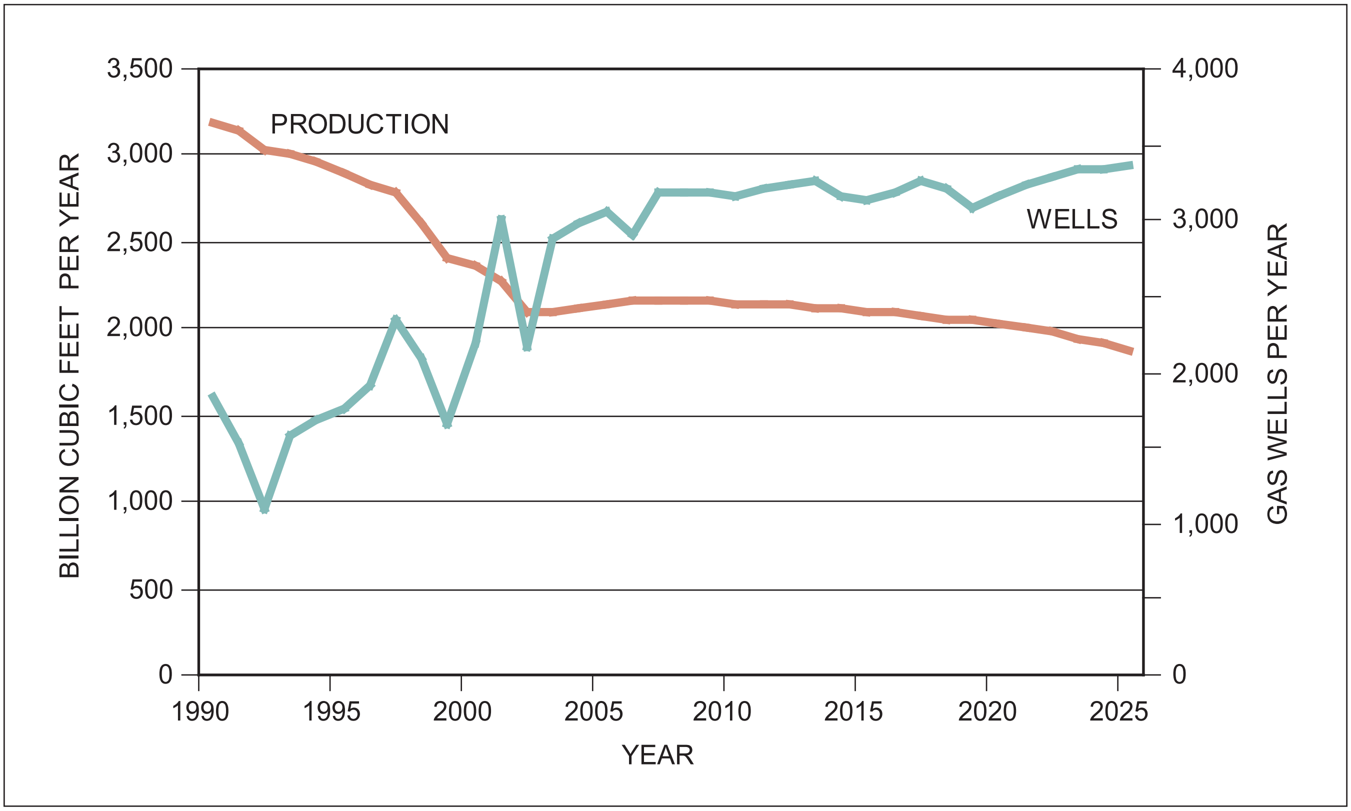

Figure S2-43. Midcontinent Production and Drilling Forecast

non-associated gas. This compares to the current NPC assessment for the Anadarko of 21.0 TCF.

The NPC examined the 5 largest plays in the Anadarko basin which accounted for about two-thirds of the undiscovered gas potential. The NPC experts increased the undiscovered gas in four of the plays and reduced it in one play.

The Deep Structural Gas play was increased from 0.9 TCF to 5.0 TCF. Over 1.5 TCF has been discovered since 1995 and consensus was that some large (> 1 TCF) discoveries are possible. Recent improvements in 3-D seismic imaging has uncovered additional large prospects in this play.

The Deep Stratigraphic Gas play was increased from 2.6 TCF to 3.2 TCF. Improved 3-D seismic imaging is helping to find new prospects in the deep parts of the basin.

The Washes play was increased from 0.4 TCF to 1.5 TCF. The play is mature in a large part of the basin but recent discoveries in the Wichita Mountain front area have opened up new exploration potential. 3-D seismic indicates several large prospects remain to be tested.

The Morrow Sandstone Stratigraphic Oil and Gas play was increased from 1.2 TCF to 1.7 TCF. The play has been heavily drilled in the basin but since it covers a large area there are still places with untested potential. The consensus was that there will be more fields found than estimated by the USGS in 1995 but their average size would be smaller.

The Lower Desmoinesian Stratigraphic play was reduced from 2.4 TCF to 1.5 TCF. This play has been heavily drilled and the remaining new fields are likely very small. The existing fields will likely show significant growth due to infill drilling.

i. Nonconventional Resources

The USGS Woodford/Chattanooga/Arkansas Novaculite play was identified as a hypothetical nonconventional fractured shale play in the 1995 assessment but no gas reserves were assigned to it. The NPC consensus was also to assign no volumes to this play since no significant commercial production has been established to date. This play may benefit from advanced technology in the future and then could possibly become economic.

No coal bed methane potential was assessed in the Anadarko basin by the USGS. The NPC agreed with this assessment.

3. Other Midcontinent Provinces

The NPC only held a workshop related to the Anadarko basin and did not discuss the other USGS provinces that make up the balance of the NPC Midcontinent Super-Region. The future gas resource of these other provinces was small relative to the major North American provinces. The NPC will use the USGS 1995 undiscovered gas values for these other provinces.

Table S2-4 lists the proved, growth, and undiscovered gas resources in TCF of the NPC Regions that make up the Midcontinent Super-Region.

NPC Region	Proved (TCF)	Growth (TCF)	Undis-covered (TCF)
Anadarko	17.7	21.4	21.0
Arkoma-Ardmore	4.8	6.8	6.4
Northern Midcontinent	1.5	4.1	4.4
Total	**24.0**	**32.3**	**31.8**

Table S2-4. Gas Resources of NPC Regions

H. Gulf Coast Onshore Super-Region

1. Super-Region Summary

The USGS 1995 assessment provides the basis for NPC's assessment of the Gulf Coast Super-Region (Figure S2-44), which includes four NPC regions onshore the Gulf of Mexico: South Texas, South Louisiana, ARKLATX (south Arkansas, north Louisiana and east Texas), and MAFLA (Mississippi, south Alabama and Florida) (Figure S2-45). Total technical resource is 183.2 TCF and cumulative production has been 321.5 TCF.

The Gulf Coast is a major super-region for current gas production and undiscovered gas. The NPC 2003

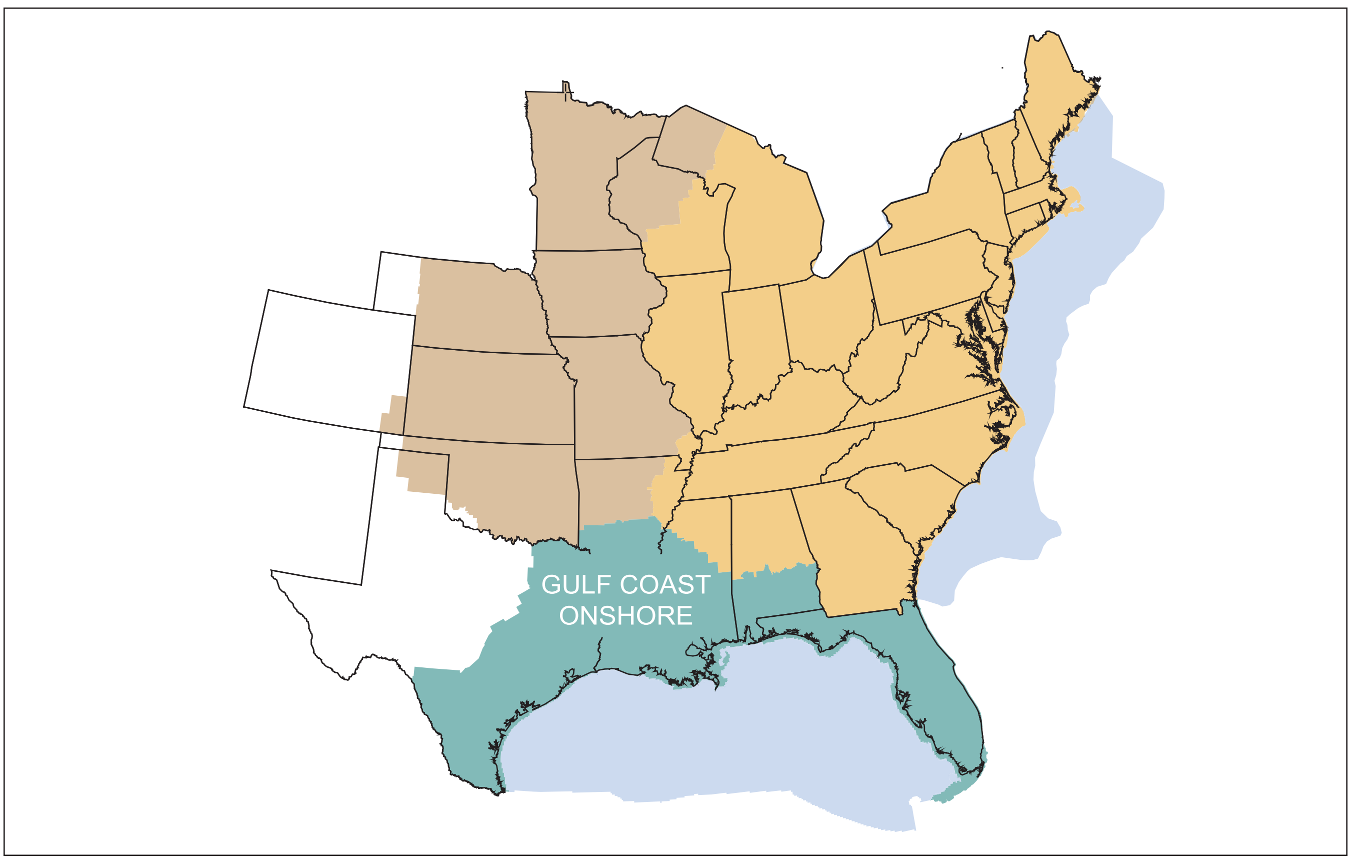

Figure S2-44. Location of the Gulf Coast Super-Region

Figure S2-45. Gulf Coast Regions

assessment is 86 TCF of undiscovered gas which is a decrease of 13 TCF from the USGS 1995 (Table S2-5). There were, however, some major changes within individual large plays. Plays that decreased are deep Tuscaloosa down 3.3 TCF, Upper Wilcox shelf edge down 2.8 TCF, Yegua down-dip gas down 3.2 TCF, Jackson down-dip gas down 3 TCF, and Norphlet down 3.3 TCF. Norphlet potential located in state waters is included in the Gulf of Mexico Super-Region.

Play Group	**USGS 1995 (TCF)**	**NPC 2003 (TCF)**
Mesozoic Carbonates/Clastics	16.9	21.0
Cotton Valley Sandstones	1.1	1.5
Deep Tuscaloosa Sandstones	6.3	3.0
Lower Tertiary Clastics Shelf Edge	14.2	8.2
Lower Tertiary Clastics Down Dip	28.5	23.5
Norphlet Mobile Bay	6.0	2.8 *
Smackover	1.3	1.3
Houston/Mississippi Salt Dome	1.7	1.7
Total (Fields >6 BCF)	**76.0**	**63.0**
Total (Including Small Fields)	**99.7**	**85.6**

* Norphlet in state waters included in Gulf of Mexico super-region.

Table S2-5. Gulf Coast Undiscovered Gas

The best undiscovered gas potential is in Mesozoic carbonate and clastic reservoirs and down-dip Tertiary sandstones. Some of these plays increased substantially: Lower Wilcox overpressured up 3 TCF, Vicksburg down-dip gas up 3.4 TCF, and James Lime up 4 TCF. The James Lime was assessed by the USGS as a conventional play but may actually be a nonconventional play according to the NPC experts and thus its potential was increased significantly.

The USGS assessed 95 plays in the Gulf Coast. The NPC combined these plays into eight super-plays based on geology, development cost, and technology factors (Figure S2-46). The eight super-plays are: Mesozoic carbonates/clastics, Cotton Valley sandstone, Deep Tuscaloosa sandstone, L. Tertiary clastics shelf edge, L. Tertiary clastics downdip, Norphlet Mobile Bay, Smackover, and Houston/Mississippi Salt Dome. Each of the super-plays is subdivided by drilling depth for economic analysis.

Gulf Coast Onshore production increased during the 1990s to its current level of around 5 TCF/year (Figure S2-47). During that time, drilling activity also increased from about 1,000 wells/year to about 3,000 wells/year. In the Reactive Path outlook, production will decline slowly to about 3.5 TCF/year by 2025 and drilling activity will decrease commensurately.

2. Gulf Coast Assessment Description

a. Remaining Gas Reserves

There are 37.5 TCF of remaining proved gas reserves in the Gulf Coast.

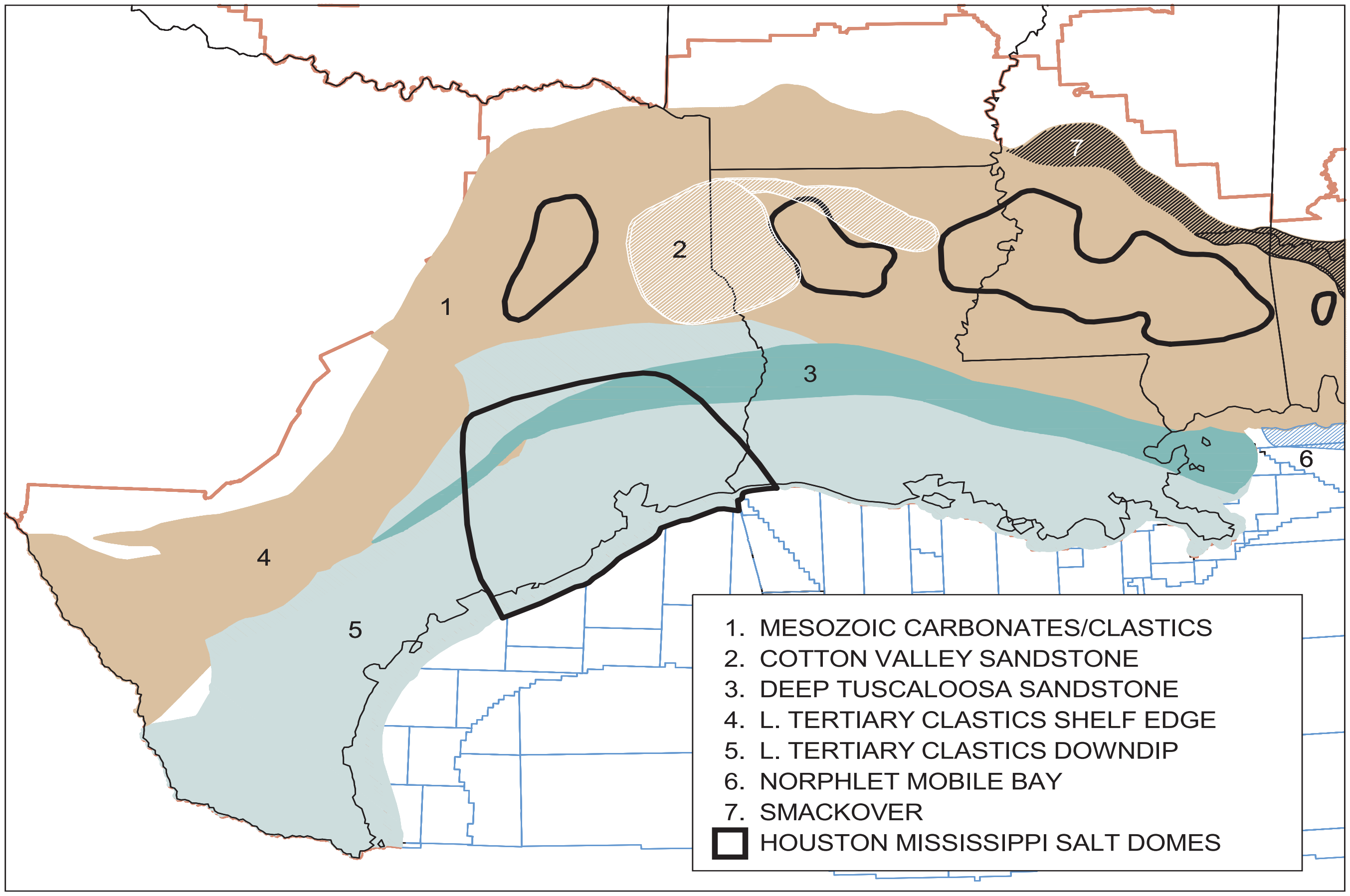

Figure S2-46. Gulf Coast Onshore Super-Plays

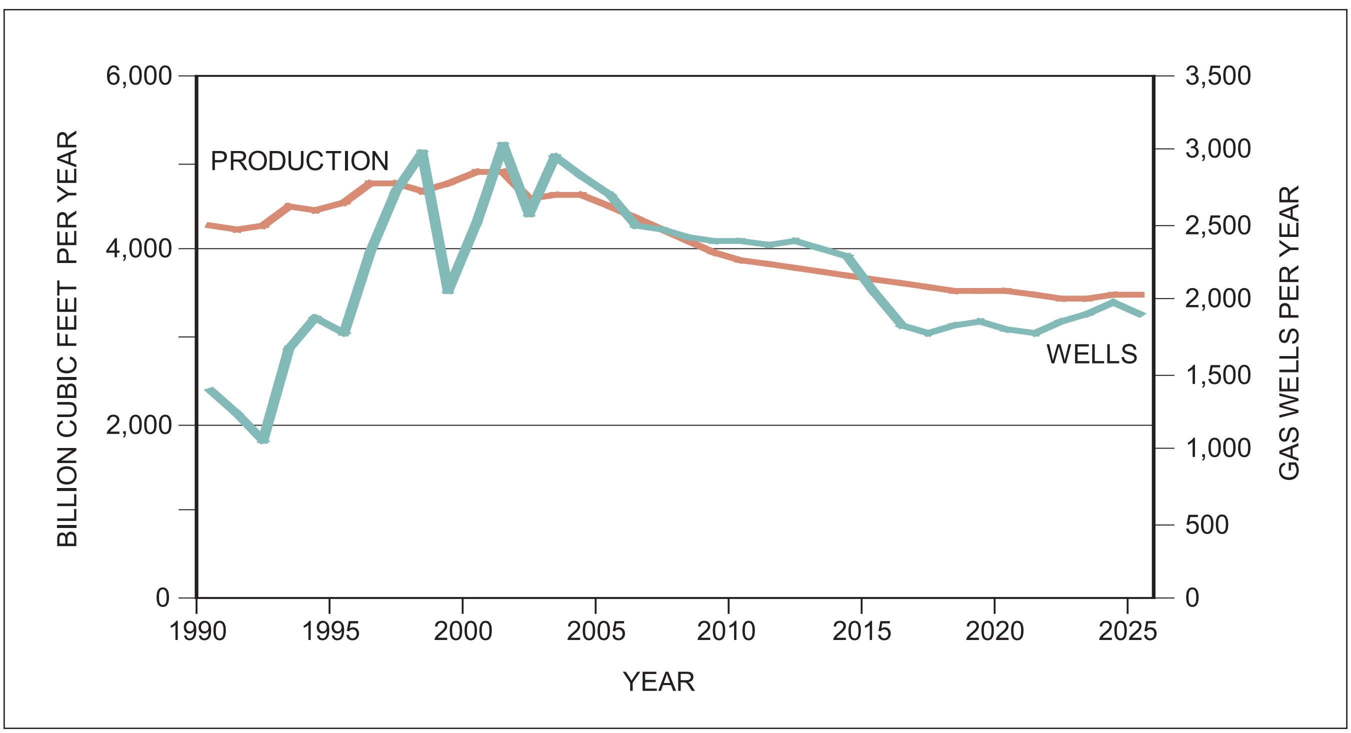

Figure S2-47. Gulf Coast Onshore Production and Drilling Forecast

b. Growth of Existing Fields

The Gulf Coast has produced 321.5 TCF of gas to date. The total future growth in these fields is estimated to be 60.2 TCF.

c. Undiscovered Fields Background Studies

The national assessment made by the USGS 1995 was used as the basis for the gas potential of the Gulf Coast. The USGS identified 95 geologic plays with gas potential. There are 91 conventional plays and four nonconventional plays. The assessment results are documented in USGS Circular 1118 (http://energy.cr.usgs.gov/oilgas/noga/index.htm).

The NPC methodology was to assemble industry, government, and academic experts on the Gulf Coast and hold a workshop to validate and change, if necessary, the mean resource estimates for key large plays. This workshop was held at the ExxonMobil office in Houston, Texas.

d. Undiscovered Fields Results

The USGS 1995 assessment estimated an undiscovered gas resource of 99.7 TCF in 95 plays in the Gulf Coast. The NPC 2003 reduced this by 14.1 TCF. A detailed description of changes in individual plays and play groupings is discussed below.

i. Mesozoic Carbonates/Clastics

Forty three (43) plays make up the Mesozoic Carbonates/Clastics play grouping. Four (4) of these were discussed in the workshop: the Lower Cretaceous Carbonate Shelf (Play 4705), Gilmer Limestone (Play 4920), James Lime (Play 4931), and the Hosston/Travis Peak Salt Basin (Play 4926).

The Lower Cretaceous Carbonate Shelf (USGS 1995 Play 4705). The play is widespread, extending from the Mexican border, across the Western Gulf, through Texas, Louisiana and to the State-Federal water boundary in southern Louisiana. Reservoirs in this play are shelf and shelf edge carbonates of the Lower Cretaceous Edwards, Stuart City, Sligo, and Pearsall Formations. Porosity is due to inter-particle dissolution of coarse-grained limestones along the shelf edge with minor intra-particle and fracture porosity and dolomitization of fine-grained limestones on the shelf. Complex inter-fingering of porous and non-porous facies coupled with complex diagenetic alteration can make reservoir development hard to predict. Various combinations of faults, facies changes and diagenetic alteration account for trapping. Source rocks are thought to be Lower Cretaceous shelf and slope mudstones. Gas, with some oil, dominates this play along the shelf edge. The shelf interior is more oil prone. Gas fields have historically been small. The median field size used in the 1995 assessment was 34 BCFG. Most of the discoveries are in South Texas, but an oil discovery in Main Pass 253 suggests the play might be prospective through Louisiana.

The play is considered high risk because remaining prospects are generally too small to detect on seismic. In Louisiana, prospects can easily be missed because 2-D seismic lines are 2-3 miles apart, too widely spaced, due to having to shoot along highways and through heavily forested areas. Since the 1995 USGS assessment there has been little activity in this play with only 4 wells drilled in the past seven years. This lack of activity suggests that Industry has a negative view of the play. Discoveries are often only 1-2 well fields and wells cost $3-4 million. The workshop consensus was to accept the USGS assessment.

The Gilmer Limestone (USGS 1995 Play 4920). The play is in Upper Jurassic Gilmer Limestone reservoirs that produce gas and oil from structural traps in the East Texas Salt Basin. The Haynesville and Cotton Valley limestones of Mississippi and Alabama are age equivalent. Reservoirs are shelf and reef limestones with porosity of up to 20%, but permeability is low (<10 mD). Traps are generally confined to structural features. Early salt movement created topographic highs that localized coarse-grained limestones and some pinnacle reefs. Structural prospects have been heavily explored with few undrilled structures remaining. Some stratigraphic traps are developed on the carbonate platform margin where porous reef facies interfinger with non-porous facies.

The play is high risk and high cost. Completed wells cost $1.5-3 million including fracture stimulation which can triple or quadruple initial well rates. The gas is sour which negatively affects economics. The workshop consensus was to reduce the mean assessment to 0.2 TCF; reduce the largest remaining discovery from 450 to 50 BCF; and reduce the median number of undiscovered accumulations to 10.

The James Lime (USGS 1995 Play 4931). This play extends from the central salt basin of Mississippi, across northern Louisiana, and into the East Texas salt basin. Reservoirs are Lower Cretaceous, Aptian age, fine-grained shelfal limestones with low porosity and permeability. The source is underlying organic mudstone. The James Lime is generally 100 feet thick, made up of chalky, micritic beds with interbedded skeletal facies. Porosity is from 5-20% and permeability 0.01-10 mD with fractures needed for production. A down-dip shelf-margin reef play is possible. Traps are thought to be mainly structural, associated with salt or faults. However, the play should likely be classified by the USGS as a continuous (nonconventional) type play as gas is pervasive throughout the formation; all wells seem to be gas saturated. The play has a potentially large technical resource, but individual well recoveries are highly variable and uncertain, and cost to develop is high. Structuring is the probable cause of fracturing which enhances permeability.

The Trawick Field produces from this play. It lies over a salt dome which increases natural fracturing. Horizontal wells can enhance production. There is no known water contact and the wells make approximately 1 BCF each with high initial rates which decline to about 0.5 MMCFG/D.

The workshop consensus was to increase the undiscovered gas from 1 TCF to 5 TCF to account for the widespread gas saturation in this play and the growing understanding of how this play might be explored for and developed. The NPC will use the USGS 1995 undiscovered field size distribution but increase the number of undiscovered fields.

The Hosston/Travis Peak Salt Basin (USGS 1995 Play 4926). This play is within deltaic and shelf sandstones of the Lower Cretaceous Hosston Formation. Traps are structurally controlled and usually associated with salt domes. Porosity can be as high as 15% and permeability 50 mD. It is difficult to distinguish the difference between gas and water-bearing sands from well log analysis which means that water production is a common problem in this play. This problem may result in overlooked gas potential so the workshop consensus was to accept the USGS assessment.

ii. Cotton Valley Sandstones

Cotton Valley Uplift (USGS 1995 Play 4924). This play is in Upper Jurassic Cotton Valley sandstones which produce gas from structural traps associated with faults and basement structures around the Sabine Uplift in East Texas and northern Louisiana. Reservoirs are deltaic and nearshore marine sandstones. Porosity can be as high as 20% and permeability 50 mD. Anadarko Petroleum has recently employed new technology that has reportedly helped discover 1 TCF. Workshop discussions suggest the play may be larger than mapped by the USGS 1995. The workshop consensus was to increase the undiscovered gas to 1.5 TCF.

iii. Deep Tuscaloosa Sandstones

Tuscaloosa Deep (USGS 1995 Play 4709). This play is in Upper Cretaceous Tuscaloosa sandstones which produce gas from structural and stratigraphic traps down-dip (south) of the Lower Cretaceous shelf margin in southern Louisiana. Boundaries of the play are where the sands are deeper than 25,000 to the south, sandstones pinch-out to the west in central Texas and the play continues into the Federal offshore to the east. Reservoirs are found in shelf margin deltas that formed down-dip from growth faults, in slope channels further down-dip and in fans in the more distal parts of the play. Clay coatings on grains may have helped preserve good reservoir properties. Porosity as high as 25% and permeability of 100mD is known at depths of 20,000 feet. The deltaic facies are trapped by roll-over anticlines while combination structural/stratigraphic traps are found down-dip in the deepwater facies.

There have not been any major discoveries in this play since the USGS 1995 assessment. Some fields are already abandoned and cumulative production to date is 4-5 TCF. Workshop participants considered the Tuscaloosa Deep to be a mature play, with all of the known larger traps having been tested. 3-D seismic surveys have been acquired over the producing area of the play but no potentially commercially size traps have been observed. Smaller fields are possible, but they may not be economic. Completed wells cost $20 million and need 200 BCF field size to be economic. There is limited exploration potential to the east/southeast and west/northwest. Large future discoveries are most likely to the south/southwest which is deeper, hotter, and higher pressure than the current producing area.

A stratigraphic play is currently developing down-dip of the Sligo shelf margin in Texas. It is expected to have small size accumulations. The Texas part of this play is in the Woodbine Formation which is stratigraphically just below the Austin Chalk and is younger than the Louisiana Tuscaloosa sandstone. The workshop consensus was to reduce undiscovered gas to 3 TCF (down 3.3 TCF).

iv. Lower Tertiary Clastics Shelf Edge

There are twenty plays in the Lower Tertiary Clastics Shelf Edge. The two that were discussed in the workshop are the Upper Wilcox Shelf Edge (Play 4722) and the Lower Wilcox Lobo Trend (Play 4718).

Upper Wilcox Shelf Edge (USGS 1995 Play 4722). This play is a narrow, but long, trend stretching from the Texas/Mexico border to offshore southern Louisiana. Reservoirs are upper Wilcox shelf-edge deltaic sandstones. Porosity can be as high as 26% and permeability 600 mD. Traps are roll-over anticlines, fault traps, or combination structural/stratigraphic traps related sand pinch-outs and faulting. The play trend is densely drilled and only small discoveries are expected in the future. The NPC consensus was to reduce undiscovered gas to 1 TCF with no future discoveries larger than 50 BCF and half the number of future discoveries assessed by the USGS.

Lower Wilcox Lobo Trend (USGS 1995 Play 4718). The Lobo gas play is a small area in southernmost Texas, but extends into Mexico. The play has been highly explored in Texas and has produced 5.6 TCF to date. Lower Paleocene to Eocene lower Wilcox deltaic sandstones can be as high as 19% but permeabilities are generally low (<10 mD). Trapping is related to extensional faulting and gravity sliding of sandstones. Most new "discoveries" are actually field extensions in the 5-15 BCF size range. Sands are predictable and field extensions average 90% success. Failures are related to incorrect structural interpretation. Well costs have reduced in the last few years which has helped activity, but current drilling is becoming marginal to uneconomic. Drainage area for wells is typically 30 to 40 acres. The USGS assessment of 3 TCF is likely not new fields but growth-to-known in existing fields. The NPC consensus was to reduce undiscovered gas to zero, but recognize additional growth to existing fields.

v. Lower Tertiary Clastics Down Dip

Thirteen plays are included in the Lower Tertiary Clastics Down Dip play grouping. Nine were discussed in the workshop: Lower Wilcox Down Dip Overpressured (Play 4720), Upper Wilcox Down Dip Overpressured (Play 4723), Middle Eocene Down Dip Sandstones (Play 4724), Yegua Down Dip (Play 4727), Jackson Down Dip (Play 4729), Vicksburg Down Dip (Play 4731), Frio Southeast Texas/South Louisiana Mid Dip (Play 4735), Frio Southeast Texas/South Louisiana Down Dip Play 4736), and Lower Miocene Slope and Fan (Play 4741).

Lower Wilcox Down Dip Overpressured (USGS 1995 Play 4720). The play is down-dip from the Lower Wilcox Fluvial Play (Play 4719) and parallels the present coastline. The down-dip limit is where the depth is greater than 25,000 feet. To the southwest the play begins at the edge of the Lobo trend and extends into southern Louisiana. The lower Wilcox sandstones are generally over-pressured and occur in shelf, slope, and fan depositional environments which are down-dip from the Wilcox Fault Zone. Porosity can be as high as 25% and permeability 250 mD. Structural traps are related to growth faults. Seals are the overlying middle Wilcox shales. The USGS 1995 assessment was 3 TCF of undiscovered gas. Several of the workstation participants felt that there is a deepwater extension of this play which was not fully assessed by the USGS. It was agreed to add .5 TCF to account for this down-dip potential. The NPC consensus was to increase the undiscovered gas to 3.5 TCF with the largest undiscovered field reduced to 300 BCF and average future fields from 60-80 BCF.

Upper Wilcox Down Dip Overpressured play (USGS 1995 Play 4723). The play is in upper Wilcox slope and fan sandstones deposited down-dip from upper Wilcox shelf edge deltas. Structural traps are associated with growth faults and shale ridges. Porosity is as high as 15% and permeability 50 mD. The play parallels the coastline from the Texas/Mexico border and crosses southern Louisiana into Federal waters of the Gulf of Mexico.

The play is mature in South Texas and is currently being explored in Central Texas where deep structures appear to be present. There is low potential in East Texas and Louisiana due to lack of reservoir sandstone. No discoveries larger than 1 TCF have been made since the 1995 USGS assessment. Failures are the result of poor sandstone development. Future advances in seismic may help image reservoir development and allow discovery of additional small fields. NPC consensus was to reduce undiscovered gas to 3 TCF (down 2.7 TCF) with the largest remaining field at 300 BCF.

Middle Eocene Down Dip Sandstones (USGS 1995 Play 4724). The play is down-dip from middle Eocene fluvial sandstones and extends from the Texas/Mexico border across southern Louisiana and into Federal waters of the Gulf of Mexico. The Queen City sandstones are shelf and possibly slope deposits in south Texas while Cook Mountain sandstones in southeast Texas are deltaic and shelf deposits. Porosity in the Cook Mountain can be as high as 30% with permeability of 350 mD. Structural traps are related to reactivated Wilcox growth faults and along deep shale ridges. The Cook Mountain play is confined to the area near Houston, Texas, and producing fields generally have seismic amplitudes which increases the success rate. Since the USGS did their assessment, there have been 10 discoveries totaling 125-150 BCF with a median field size of about 20 BCF; the largest discovery was 60 BCF. Workshop consensus was to keep the USGS mean assessment of 1.2 TCF, but increase the undiscovered large field size to 250 BCF and increase the number of undiscovered fields to 12-55-120 (min-med-max). Houston, Texas urban sprawl creates a significant access issue, especially for seismic acquisition, which is critical for successful exploration.

Yegua Down Dip (USGS 1995 Play 4727). The Yegua Play extends from the Texas/Mexico border across southern Louisiana into Federal waters of the Gulf of Mexico. Over-pressured slope and distal fan sandstones with porosity locally as high as 25% and permeability of 100 mD are the reservoirs in the Yegua. Combination structural/stratigraphic traps related to Yegua growth faults and possibly along shale ridges combine with variations in deepwater sandstone reservoir quality make this is relatively high risk play. Several discoveries were made in the Central Texas coastal area in the 1980s and early 1990s which gave optimism to the USGS assessment, but few discoveries have been made since 1994. There have been fifteen discoveries in South Texas and in the Houston Embayment since 1994 totaling 300-400 BCF with a median size of 25 BCF (the same as assessed by the USGS); the largest discovery was 110 BCF. El Paso drilled the Yegua under the glide plane fault without success – no hydrocarbons and tight sand. The NPC consensus was to reduce undiscovered gas to 2 TCF (down 3.2 TCF), reduce the largest undiscovered field to 150 BCF, and increase the number of future discoveries but they will be smaller in average size.

Jackson Down Dip (USGS 1995 Play 4729). The play is conceptual with no known discoveries. The play is in Jackson slope and fan sandstones similar to the other down-dip plays assessed by the USGS. The interval is not generally believed to be sand-prone but is rather a shale-prone interval. The USGS play risk of 50% was deemed too optimistic and the NPC consensus was removing this play from the assessment.

Vicksburg Down Dip (USGS 1995 Play 4731). This play is in Oligocene shelf, shelf-edge delta, slope. and fan sandstones down to 25,000 feet. The play parallels the coastline and extends from the Texas/Mexico across southern Louisiana into Federal waters of the Gulf of Mexico. Most of the drilling activity is in South Texas targeting shelf edge deltaic deposits. Porosity can be as high as 30% in shallow targets, but only up to 15% in down-dip overpressured targets. Permeability can be as high as 2 darcies up-dip but is less than 10 mD down-dip. Combination structural/stratigraphic traps are related to faults, rollover anticlines and shale structures combined with sandstone facies pinch-outs.

This play is considered to still have good undiscovered potential in the Houston Salt Basin, Rio Grande Embayment, and western Louisiana, but it probably does not extend into central and eastern Louisiana as shown on the USGS play map. Remaining prospectivity is related to recent technology advances in fracture technology and 3-D seismic imaging. This is a tight gas play that was considered high risk at the time of the 1995 USGS assessment. The USGS 1995 assessed 1.5 TCF of undiscovered gas and at least that much has been discovered since then. Examples are McAllen Ranch (El Paso) which is estimated at 1 TCF, N.E. Jefferies Field discovered in 1997 has 250 BCF, Monte Cristo is also reported to have discovered 1 TCF, and Santa Fe Ranch reportedly discovered 250 BCF. In South Texas the play is highly overpressured, but modern seismic shows there are numerous prospects. The King Ranch is considered to be prospective and a Hunt Oil well to the north of the Ranch, near Corpus Christi has triggered activity in the vicinity. The Davis discovery in Galveston Bay has also triggered activity. At depth this play reaches 420 degrees F and is at the limit for fluids used in fracture stimulation. The sands do not extend east of the Hackberry Embayment in western Louisiana. There may be some potential for additional Vicksburg resources to the east further down-dip in very deep fault blocks, but currently the extension is technology limited; sands are expected to be very tight and wells would be very expensive to drill. The NPC consensus was to raise undiscovered gas to 5 TCF, increase the largest undiscovered field size to 800 BCF, and raise the number of undiscovered fields to 40-100-250 (min-med-max).

Frio Southeast Texas/South Louisiana Mid Dip (USGS 1995 Play 4735). The play was discussed briefly with consensus opinion to accept the USGS assessment without modification.

Frio Southeast Texas/South Louisiana Down Dip play (USGS 1995 Play 4736). The play was discussed briefly. The consensus was to make no change to the mean assessment, but reduce the median undiscovered field size to 10 BCF and increase the number of new fields from 5 to 10.

Lower Miocene Slope and Fan (USGS 1995 Play 4741). The play was discussed briefly with consensus opinion to accept the USGS assessment without modification.

vi. Norphlet

Five (5) plays make up the Norphlet with one discussed in the workshop.

The Norphlet Mobile Bay Deep Gas (USGS 1995 Play 4903). The play is in Upper Jurassic Norphlet sandstones that produce gas from structural traps in the Mobile Bay area of Alabama State waters and adjacent Federal waters. The play is defined to be limited on the north by large Louann Salt structures on the southern flank of the Wiggins-Hancock Arch. The offshore limit for the USGS assessment is the State-Federal water boundary. The MMS assessed the play potential in Federal waters.

In Mobile Bay north to south trending dune sandstones are structured by underlying salt swells. The dune facies is good reservoir while the interdune sabkha facies are basically non-reservoir. The upper part of the Norphlet has a regional low permeability zone which can cause failures if this non-reservoir tight zone is the only sandstone within structural closure. The overlying Smackover Formation is both source and seal. Average depths are 20,000 to 22,000 feet and the reservoir is slightly overpressured.

Workshop participants felt that the play area is more limited than assessed by the USGS. The western limit of the Norphlet is the Wiggins Arch, the northern limit is in central Mississippi striking southeast into southern Alabama and just to the north of Mobile Bay there are no more salt swells which results in a no large structures beyond that limit. Structures north of the salt swells are small and are related to rift faults. South of the state/federal offshore boundary, large growth faults develop that also result in only small structures being present.

The play is very mature in the Norphlet "sweet spot" of Alabama state waters. The area is covered with seismic data and all the large prospects have been tested. There have been no new discoveries in Alabama state waters since the 1995 assessment. Workshop participants believe that the best undiscovered potential is in Florida state waters but there is no access to this portion of the play.

Both the USGS (state waters) and MMS (OCS) assessments assume that the largest pool in the play is still undiscovered, but good seismic coverage and data suggest the largest fields are already discovered. The play is well explored in Alabama where access is not an issue. Possibly a larger pool might be found offshore Florida where there is limited seismic. The ChevronTexaco Destin Dome discovery is in the Norphlet and has a thick gas column, but reservoirs are thin, of poor reservoir quality and structurally segmented. In that area the Norphlet appears to be mostly Sabkha facies. The workshop consensus was to reduce the undiscovered gas to 2 TCF (down 3.3 TCF) and to attribute most of the 2 TCF to Florida state waters. In Florida state waters large fields are still possible. There is an additional 6 TCF of undiscovered gas in the federal OCS.

There are a number of technology issues associated with this play. High pressure and high temperature conditions currently limit the play to the south. Hydrogen sulfide gas is a severe limitation; offshore treating is impractical and produced gas must be piped to onshore facilities for treatment. Introduction of turbines has reduced drilling time from 5 months to 2 months. Potential enabling technologies include: 3-D seismic inversion and other new processing techniques, seismic volume attributes, advances in aeolian stratigraphy, reservoir modeling/simulation, new bits, turbines to improve drilling rate, improved high pressure-high temperature (HPHT) equipment, and fracture stimulation technology. Potential constraints include: seismic resolution, hydrogen sulfide, cost of HPHT equipment, cost of corrosion resistant tubing, and overpressure drilling and completions.

vii. Smackover

There are two (2) plays in the Smackover. The USGS assessment is accepted without modification.

viii. Houston/Mississippi Salt Dome

Two (2) plays make up the Houston/Mississippi Salt Dome. The USGS assessment is accepted without modification.

ix. Nonconventional Resources

There were four nonconventional plays assessed by the USGS in 1995. Three were in the Austin chalk and the other was Cotton Valley blanket sandstone gas play. Recent work by the USGS (Bartberger and others, 2002) indicates that the Cotton Valley blanket sandstone is primarily a conventional play (http://pubs.usgs.gov/bul/b2184-d).

No coal bed methane potential for the Gulf Coast was assessed by the USGS in 1995. There has been additional research by the USGS and others since then and a preliminary gas-in-place of 4-8 TCF for the Gulf Coast has been published but no assessment of recoverable gas is yet available (http://pubs.usgs.gov/of/of00-143). For this reason and the fact that the coals here are fairly thin, the NPC 2003 did not assess any coal bed methane in the Gulf Coast. There is current drilling to develop coal bed methane near Eagle Pass in south Texas which will shed light on the commercial feasibility of coal bed methane production in this area.

I. Gulf of Mexico Super-Region

1. Super-Region Summary

The 2000 MMS assessment of resources provides the basis for NPC's assessment of the Gulf of Mexico (Figure S2-48). The NPC generally agreed with the undiscovered resource size of the MMS but reallocated it among plays. The shallow Plio-Pleistocene plays are at a relatively mature stage of exploration and were considered to be over-assessed. The deeper Miocene is recognized to be a more difficult and less mature exploration target, having the possibility of a number of large fields remaining to be found and is possibly under-assessed. The NPC consensus is to move 15 TCF of undiscovered potential from the Plio-Pleistocene to the Miocene and Texas Deep Shelf plays. In addition, the NPC added 7 TCF to the undiscovered gas resource

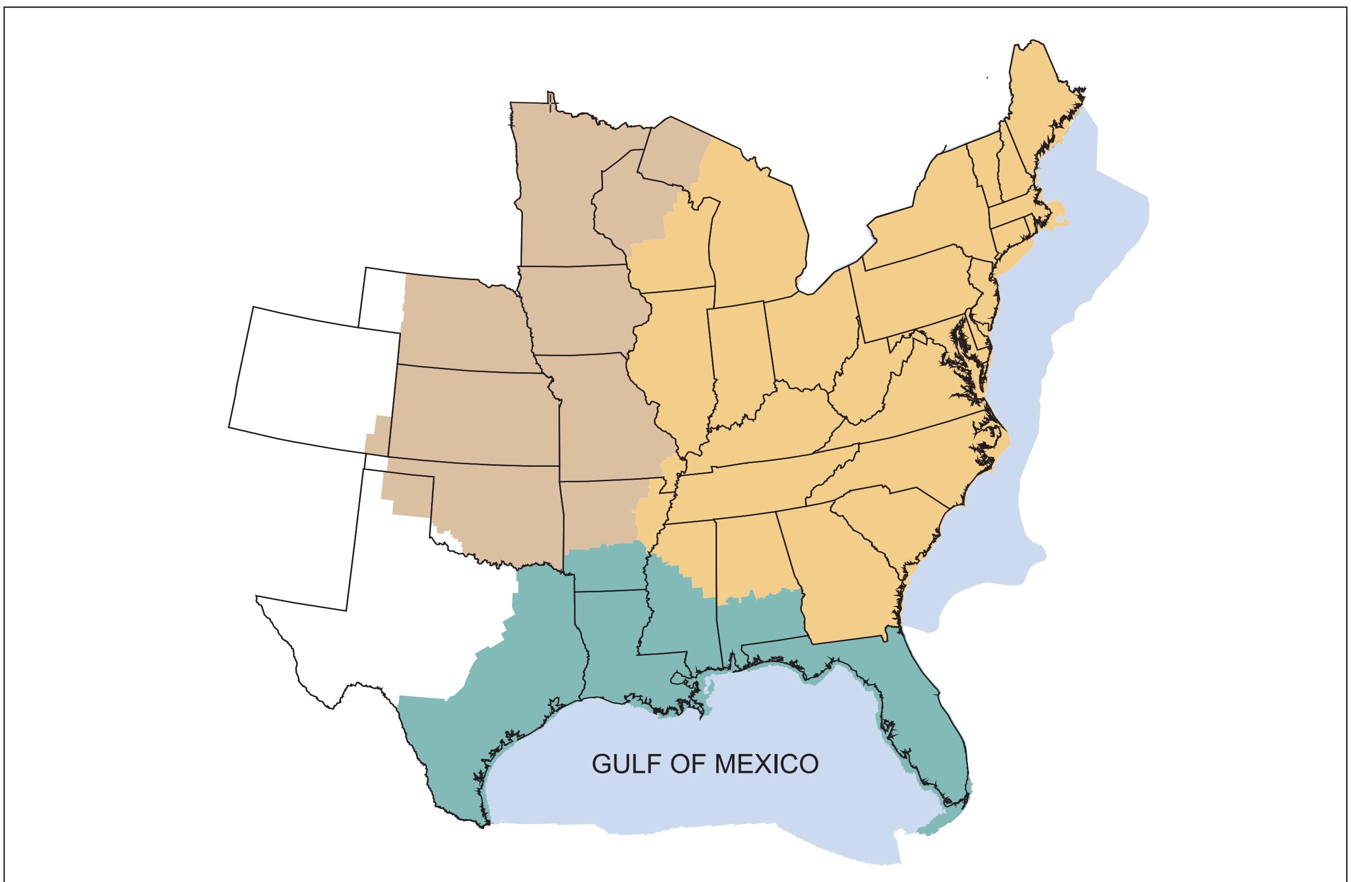

Figure S2-48. Location of the Gulf of Mexico Super-Region of the Eastern Gulf of Mexico. The NPC total undiscovered resource is 244.4 TCF.

Total technical resource is 328.8 TCF and cumulative production has been 163.1 TCF.

The MMS makes an attempt to estimate most likely reserves of Gulf of Mexico Fields. The MMS has collected statistics for approximately 1000 fields in the Gulf of Mexico and calculated a growth factor of about 4.6 to apply to the initial MMS estimate of newly discovered field size. As the field is produced the uncertainty about its ultimate size lessens. The MMS uses "grown" field size history by play to help forecast undiscovered field sizes. The NPC has elected to calculate field growth using a method developed by Energy and Environmental Analysis (EEA) where estimated ultimate recoveries of new gas wells are observed to decline compared to wells drilled earlier in the field history. These historical trends are extrapolated and adjusted using Energy Information Administration (EIA) proved reserve data for the Gulf of Mexico to estimate future field growth.

The MMS divided the Gulf of Mexico into a total of 92 plays. The NPC combined these into 6 super-plays based on geology, costs, technology factors, and land access considerations: Plio-Pleistocene, Miocene, Foldbelts, Texas Deep Shelf, Eastern Gulf of Mexico, and Central Gulf of Mexico Norphlet (Figure S2-49). Each of these is subdivided based on average water depth and drilling depth for economic modeling.

In the Reactive Path outlook current production of about 5.4 TCF/year will peak in 2015 at about 5.8 TCF/year and decline thereafter (Figure S2-50). Drilling activity of 400-600 wells/year will be required to meet this outlook.

2. Gulf of Mexico Assessment Description

a. Remaining Gas Reserves

There are 29.2 TCF of remaining proved gas reserves in the Gulf of Mexico. In addition, there is 0.7 TCF of discovered gas in the Eastern Gulf of Mexico which has not been developed due to permitting and regulatory problems. The most recent MMS reserve estimation for the Gulf of Mexico is "Atlas of Gulf of Mexico Gas and Oil Sands" by Bascle, et al, 2001 (http://www.gomr.mms.gov/homepg/gomatlas/SummaryReport.pdf).

b. Growth of Existing Fields

There have been over 1000 oil and gas fields discovered in the Gulf of Mexico which have produced over 163 TCF to date. The total future growth in the Gulf of Mexico is estimated to be 54.6 TCF.

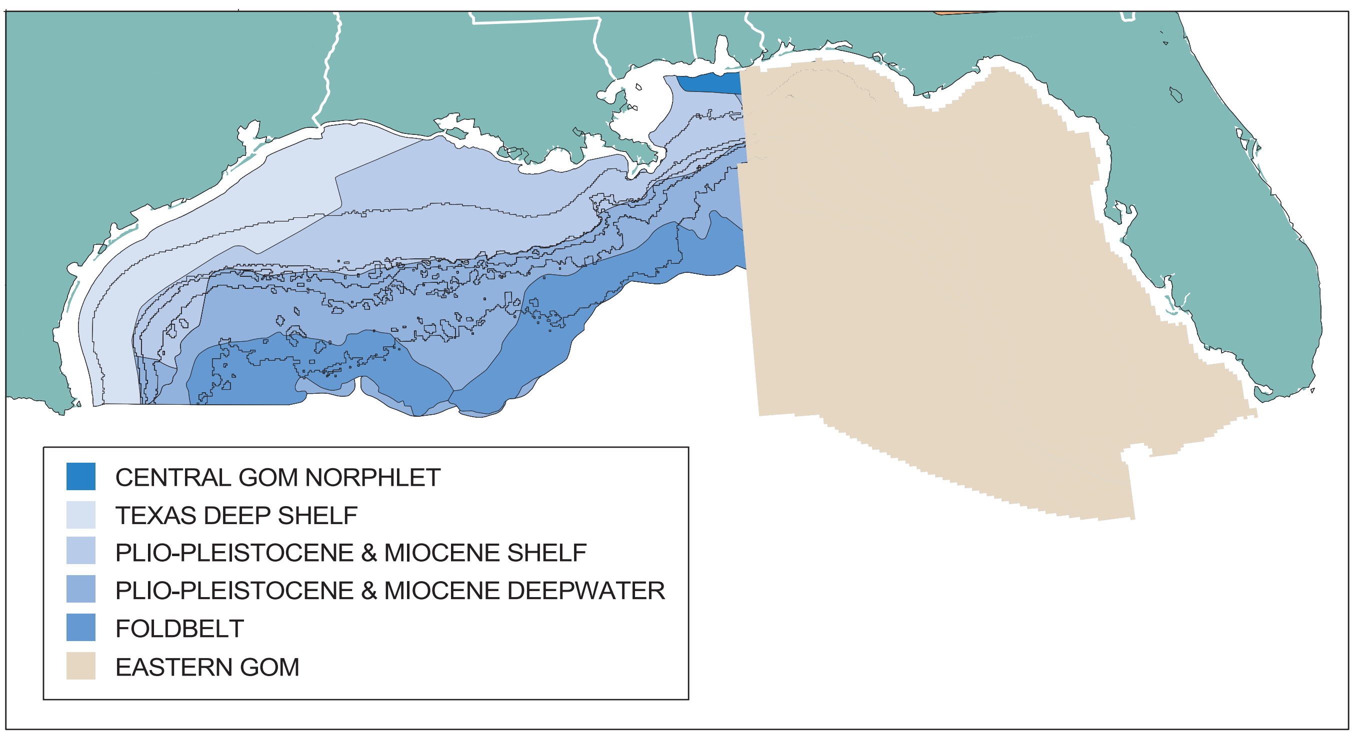

Figure S2-49. Gulf of Mexico Super-Plays

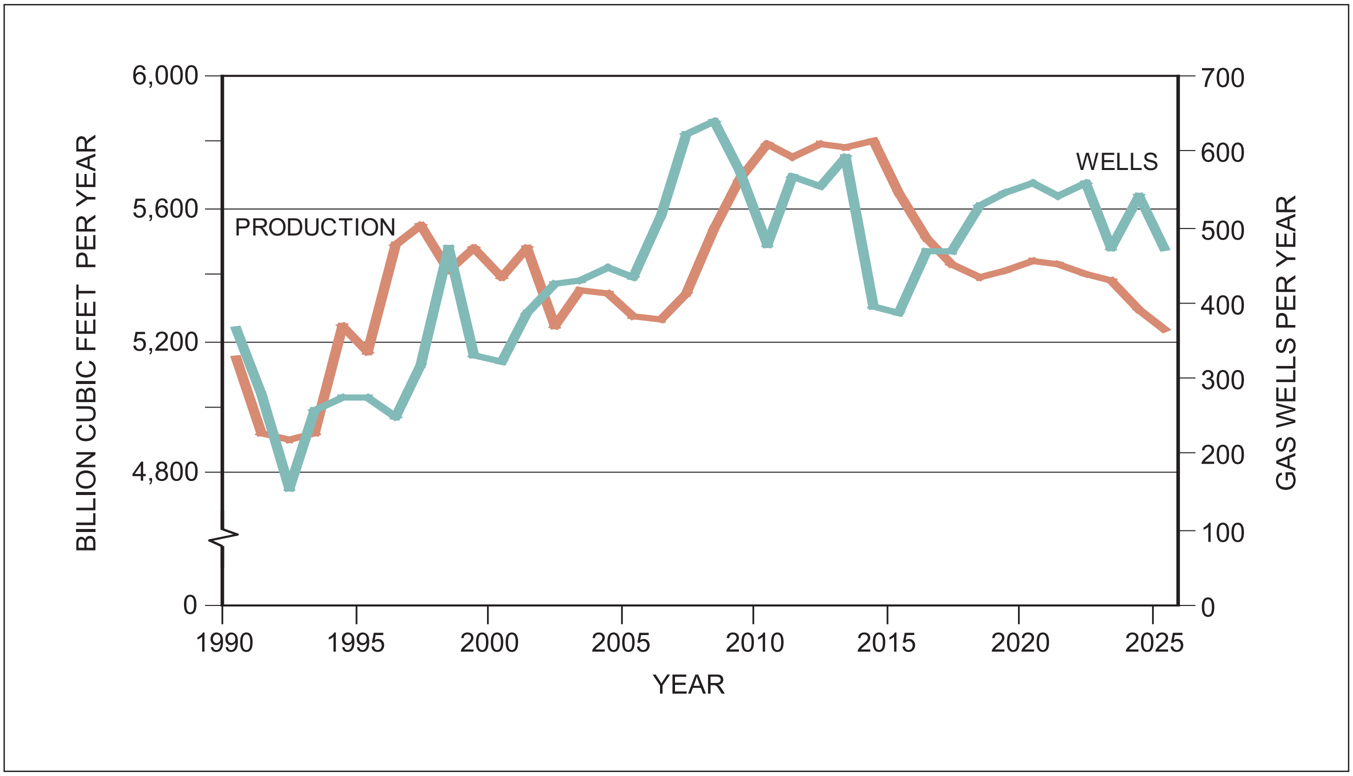

Figure S2-50. Gulf of Mexico Production and Drilling Forecast

c. Undiscovered Fields Background Studies

The most recent MMS assessment of undiscovered fields was used as the starting point for the NPC 2003 study. Details of the MMS methodology for predicting future oil and gas resources in the Gulf of Mexico can be found in "2000 Assessment of Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 1999" by Gary L. Lore, et al; OCS Report MMS 2001-087 (http://www.gomr.mms.gov/homepg/offshore/gulfocs/assessment/assessment.html).

The NPC methodology was to assemble industry and government Gulf of Mexico experts and hold a four-day workshop to validate and change, if necessary, the mean resource estimates for key large plays. This workshop was held near the MMS office in New Orleans, Louisiana.

d. Undiscovered Fields Results

The MMS assessed a total of 92 plays in the Gulf of Mexico. The NPC lumped those plays into groups of similar age and/or structural style into super-plays. The NPC super-plays are the following: Plio-Pleistocene, Miocene, Foldbelts, Texas Deep Shelf, Eastern Gulf of Mexico, and Central Gulf of Mexico Norphlet (Figure S2-49).

The MMS estimated that there is 192 TCF of undiscovered gas resource in the OCS portion of the Gulf of Mexico. The NPC added 7 TCF to the undiscovered total and reallocated the MMS estimate. For the Plio-Pleistocene superplay, 15 TCF was subtracted due to the maturity of the play. 10 TCF was added to the Miocene superplay due to the chance for additional large subsalt discoveries. The Foldbelt superplay was not changed. For the Texas deep shelf, 5 TCF was added due to few well penetrations and some recent large discoveries. The Central Gulf of Mexico Norphlet was not changed. For the Eastern Gulf of Mexico, 7 TCF was added due to favorable potential in the deepwater salt roller play (Table S2-6).

J. U.S. Atlantic Offshore Super-Region

1. Super-Region Summary

The 2000 MMS assessment of resources provides the basis for the NPC's assessment of the offshore Atlantic (Figure S2-51). The undiscovered gas resource is about 32.8 TCF which is split fairly evenly between the south, central, and northern areas. Most of the potential is in

Super-Play	MMS 2000 (TCF)	NPC 2003 (TCF)
Plio-Pleistocene	55	40
Miocene	93	103
Foldbelts	23	23
Texas Deep Shelf	5	10
Eastern GOM	12	19
Central GOM Norphlet	4	4
Total	**192**	**199**

Table S2-6. Gulf of Mexico Undiscovered Gas Before NPC Small Field Adjustment – Comparison of NPC and MMS

Cretaceous and Jurassic sandstone reservoirs (Table S2-7). This potential is in water depths ranging from 300 to 3,000 feet. There has been no production from this super-region.

The offshore Atlantic has had limited exploration. There have been a total of 42 wells drilled in the offshore Atlantic in the late 1970s and early 1980s. These wells are located in the Georges Bank (offshore Boston), Baltimore Canyon trough (offshore Atlantic City, NJ), and Brunswick areas (offshore Georgia) (Figure S2-52). There was one gas discovery in the Baltimore Canyon trough which was not developed because it was considered to be uneconomic at the time (1979-1980).

Figure S2-51. Location of the U.S. Atlantic Offshore Super-Region

The MMS plays were combined into super-plays based on geology, age, and other factors. The super-plays are: Lower Cretaceous clastics, Upper Jurassic clastics, Middle Jurassic clastics, and Mesozoic carbonates.

U.S. Atlantic Super-Play	MMS 2000 (TCF)	NPC 2003 (Includes Small Field Adjustment) (TCF)
Lower Cretaceous Clastics	11.8	13.9
Upper Jurassic Clastics	9.0	10.6
Middle Jurassic Clastics	4.9	5.8
Mesozoic Carbonates	2.1	2.4
Total	**27.8**	**32.8**

Table S2-7. U.S. Atlantic Offshore Undiscovered Gas by Super-Play

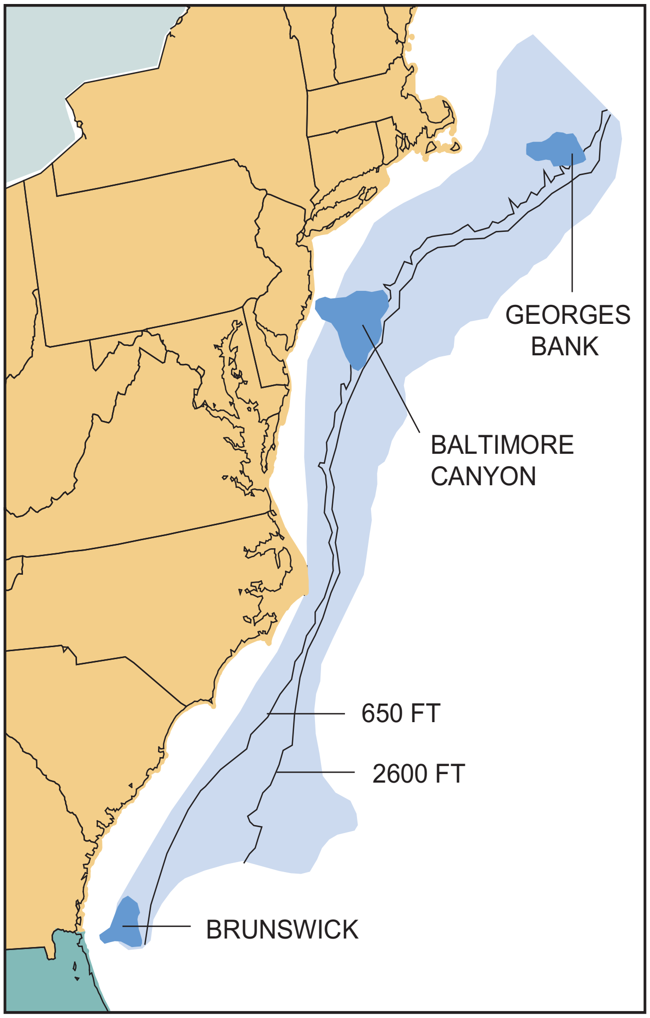

Figure S2-52. U.S. Atlantic Offshore – Super-Plays Overlay One Another (Light Blue) with Areas of Historical Wildcat Drilling (Dark Blue)

2. Offshore Atlantic Assessment Description

a. Remaining Gas Reserves

There are no proved reserves in the U.S. offshore Atlantic since the one discovery was not developed.

b. Growth of Existing Fields

This is not applicable since this involves the growth of a field during its producing life and there is no production offshore Atlantic.

c. Undiscovered Fields Background Studies

Assessments by the MMS updated in 2000 were used as the basis for the assessment of offshore Atlantic (http://www.mms.gov/revaldiv/RedNatAssessment.htm). A more detailed report for the offshore Atlantic with play level analysis is "2000 Assessment of Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 1999" by Gary L. Lore, et al; OCS Report MMS 2001-087 (http://www.gomr.mms.gov/homepg/offshore/gulfocs/assessment/assessment.html).

The NPC did not hold an industry workshop on the offshore Atlantic but accepted the MMS assessment as the basis for our estimate of undiscovered resources.

d. Undiscovered Fields Results

The MMS assessed a total of 6 plays in the offshore Atlantic. The NPC combined those plays into super-plays: Lower Cretaceous clastics, Upper Jurassic clastics, Middle Jurassic clastics, and Mesozoic carbonates.

The MMS estimated that there is 28 TCF of undiscovered gas resource in the offshore Atlantic. The NPC accepted the MMS assessment without change, except for small field adjustments.

K. Eastern Interior Super-Region

1. Super-Region Summary

The Eastern Interior super-region (Figure S2-53) is made up of three NPC regions: Appalachian Basin, Michigan & Illinois Basins, and Black Warrior Basin (Figure S2-54). The Eastern Interior is an important gas producing super-region and also one of the largest potential sources of nonconventional gas.

The USGS 1995/2002 resource assessments form the basis for the NPC's Eastern Interior assessment. The NPC total undiscovered gas is 92 TCF which is 8 TCF lower than the most recent USGS assessment. Most of the Eastern Interior undiscovered gas (83%) is in nonconventional plays such as coal bed methane, fractured shale gas and tight sandstones.

Total remaining technical resource is 110.2 TCF and cumulative production has been 54.9 TCF.

Several nonconventional plays have been extensively developed in recent years including coal bed methane in the Black Warrior and Appalachian Basins and fractured shale gas in the Michigan and Appalachian Basins.

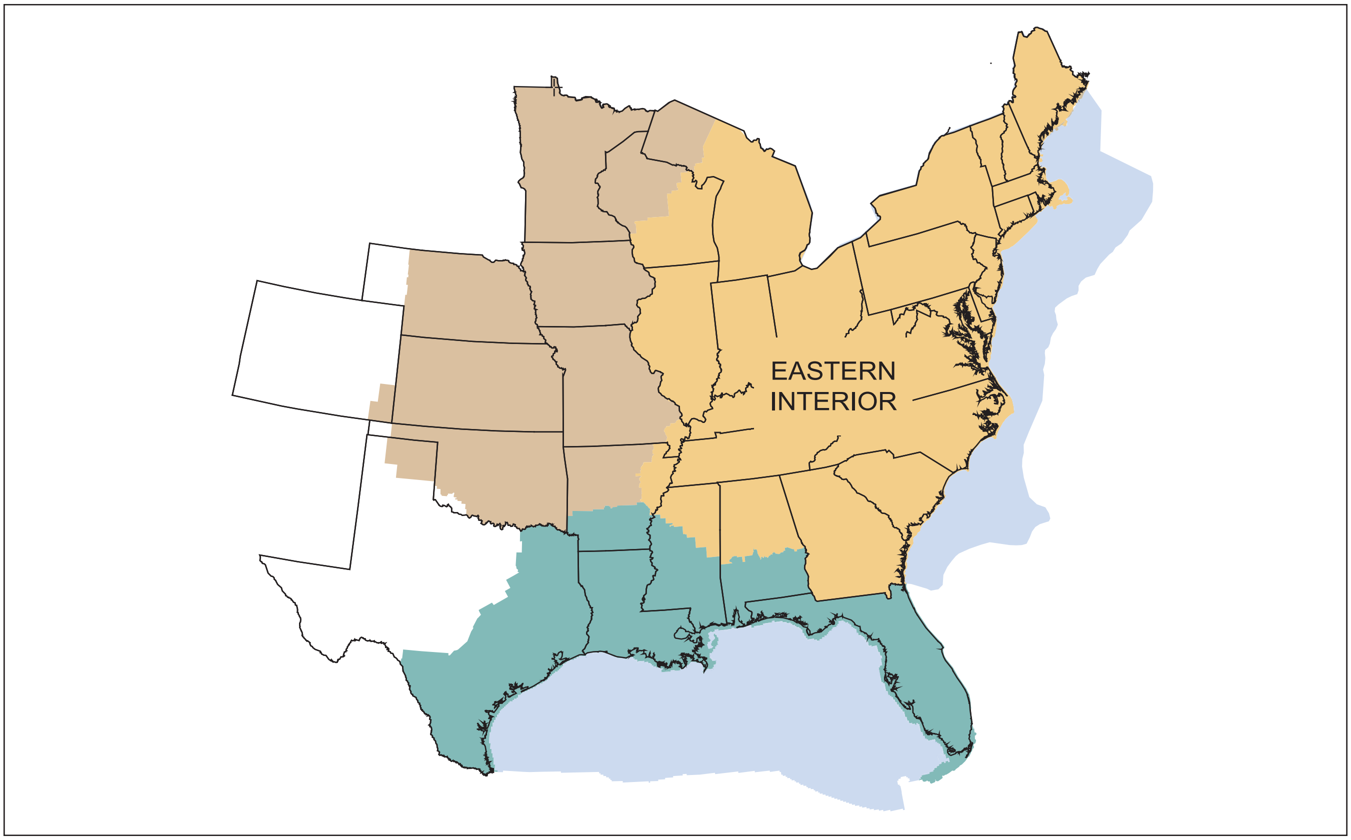

Figure S2-53. Location of the Eastern Interior Super-Region

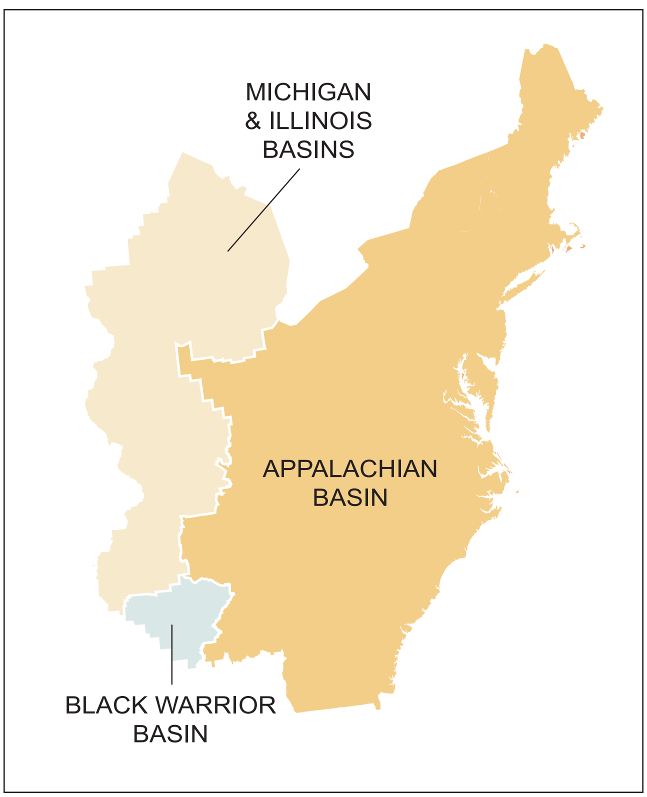

Figure S2-54. Eastern Interior Regions

In the Reactive Path outlook, production will double from its current level of 0.9 TCF/year to about 1.8 TCF/year by 2025 (Figure S2-55). Drilling activity will also double from about 3,500 wells/year to about 7,000 wells/year.

2. Eastern Interior Assessment Description

a. Remaining Gas Reserves

There are 13.7 TCF of remaining proved gas reserves in the Eastern Interior.

b. Growth of Existing Fields

The gas production in the Eastern Interior comes from the Appalachian primarily with Michigan/Illinois Basins second and Black Warrior Basin third. There has been a total of 54.9 TCF produced to date with most of that (45.9 TCF) coming from the Appalachian region. The total future growth in the conventional oil and gas fields is estimated to be 4.8 TCF. Nonconventional plays as assessed do not have future growth. The existing wells make up reserves and the remaining undrilled locations within the play outline are captured in the undiscovered gas category.

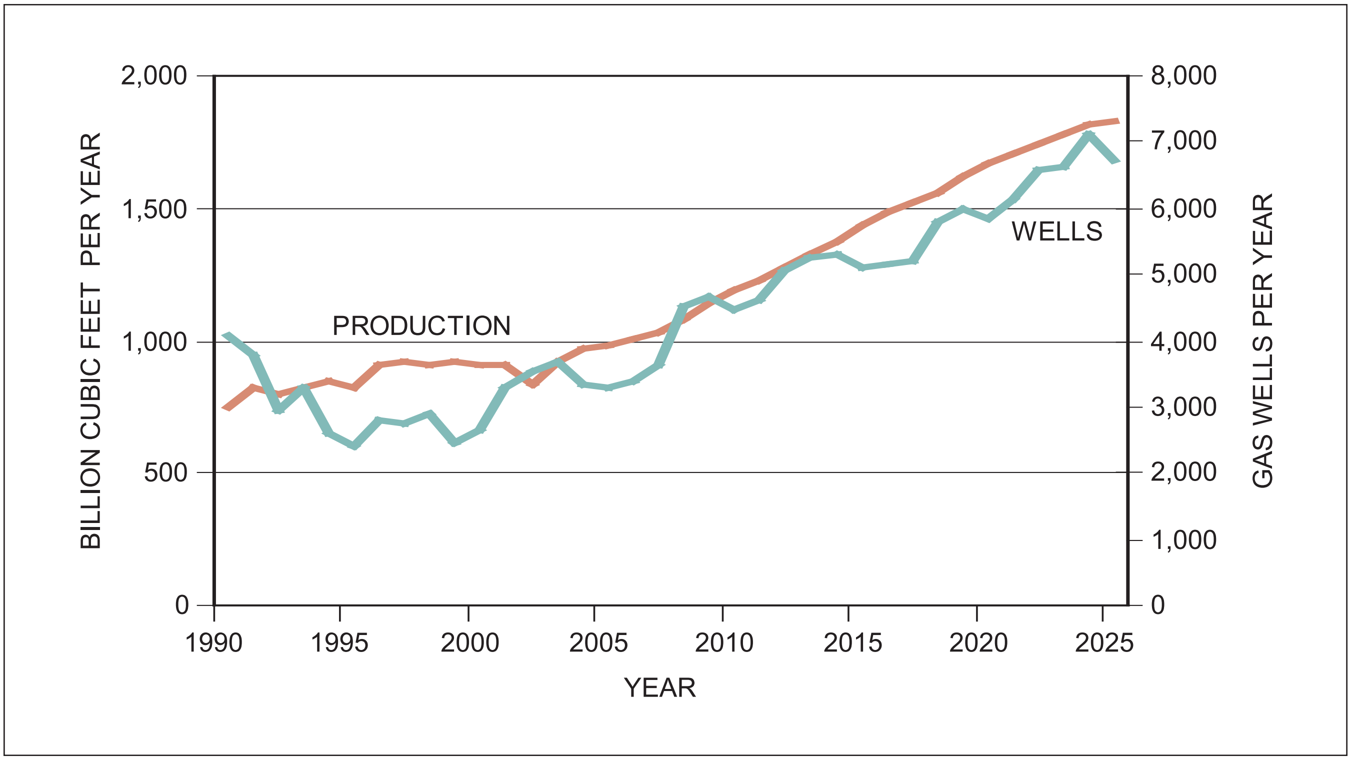

Figure S2-55. Eastern Interior Production and Drilling Forecast

c. Undiscovered Fields Background Studies

Assessments by the USGS were used as the basis for the assessment of onshore Alaska. The USGS did an assessment of the entire onshore U.S. in 1995 (http://energy.cr.usgs.gov/oilgas/noga/index.htm). In addition, the USGS published updated assessments for the following basins in 2003: Appalachian Basin and Black Warrior Basin (http://energy.cr.usgs.gov /oilgas/noga/index.htm).

The NPC methodology was to assemble industry and government Eastern Interior experts and to hold two workshops to validate and change, if necessary, the mean resource estimates for key large plays. These workshops were held at the USGS office in Reston, Virginia and in the ExxonMobil office in Houston, Texas.

d. Undiscovered Fields Results for the Eastern Interior Super-Region

The undiscovered gas in the Eastern Interior has been assessed by 70 USGS-defined plays and assessment units (Gautier and others, 1996; Milici and others, 2003). Fifteen of the plays/assessment units defined by the USGS have not been quantitatively assessed. Twenty-five of the 70 plays/assessment units represent nonconventional plays. Major coal bed methane production is from Carboniferous coals in the Appalachian, Black Warrior, and Illinois Basins. Fractured shale gas production is from Devonian black shales of the Appalachian, Michigan, and Illinois Basins.

The USGS 1995 assessment of undiscovered oil and gas potential in the onshore United States (Gautier and others, 1996) forms the basis for the NPC 2003 gas assessment for the Eastern Interior. Hydrocarbon plays with undiscovered gas greater than 2 TCF were examined in detail by the NPC Supply Task Group. During 2003, the USGS published reassessments of the Appalachian Basin (Milici and others, 2003) and Black Warrior Basin (Hatch and others, 2003). These assessments included revision of United States Geological Survey 1995-defined hydrocarbon plays into a series of Total Petroleum Systems and accompanying Assessment Units. Assessment Units with greater than 2 TCF gas potential were evaluated in the same manner as the 1995 plays. The 1995 plays were correlated with the 2003 assessment units to avoid double counting. Two workshops were held during early 2003 to which industry, government, and academic experts were invited to evaluate and change, if necessary, the mean resource estimates for these key large plays.

The National Petroleum Council's 2003 assessment for the Eastern Interior super-region is 91.8 TCF which is a decrease of 9 TCF relative to the USGS 1995/2003 (using USGS 2003 where available as the standard of reference). Significant decreases in the undiscovered gas resource involve the Appalachian (4.5 TCF decrease) and Michigan Basins (3.4 TCF decrease). A more detailed discussion of these basins is presented below.

i. Appalachian Basin Region Summary

The Appalachian Basin is located in New York, Pennsylvania, Ohio, West Virginia, Tennessee, and Alabama. Devonian fractured black shales constitute the most important gas-producing interval in the basin. Coal bed methane production is primarily from the Carboniferous coal beds.

The NPC has estimated undiscovered gas at 66.1 TCF. Conventional undiscovered gas accumulations represent 9% of the undiscovered gas resource. Nonconventional low permeability sandstones represent 56%, Devonian fractured shale gas is 21%, and Carboniferous coal bed methane comprises 14% of the undiscovered gas resource.

The NPC estimate is a 4.5 TCF decrease from the USGS 2003 estimate (Milici and others, 2003). This decrease is due to a reduction in average expected gas recovery per undrilled location ("cell") for the Clinton-Medina Basin Center and Clinton-Medina Transitional Northeast Assessment Unit. This in turn is based on updated well performance histories provided by Appalachian Basin operators and experts. The Greater Big Sandy fractured-shale, Marcellus Shale, and Catskill nonconventional sandstones and siltstones assessment units gas estimates are increased from 20 TCF to 28.1 TCF based on improved chances of success and more optimistic views by basin operators of the fracture system quality within the Greater Big Sandy assessment unit. The Catskill sandstones and siltstones assessment unit was increased based on basin operators input with respect to a more significant volume of sand potentially being available and the fact that the eastern portion of the assessment unit is relatively untested.

ii. Michigan Basin Region Summary

The Michigan Basin is located in Michigan, western Wisconsin and northern Indiana. The Antrim fractured shale gas play is the most significant play for undiscovered gas.

The NPC has estimated undiscovered gas at 19.8 TCF. Conventional undiscovered gas accumulations represent 41% of the undiscovered gas resource. Nonconventional low permeability sandstones and Antrim fractured shale gas make up the other 59%. The Antrim shale play is the largest play with 41% of undiscovered gas.

The Antrim Shale (Devonian) biogenic, fractured black shale play of the Michigan Basin is a continuation of the productive fractured shale plays of the Appalachian and Illinois Basins. The USGS 1995 estimate of undiscovered gas is 18.8 TCF (Gautier and others, 1996). The NPC 2003 Supply Task Group reviewed the play in conjunction with industry and government experts, and decreased it to 7.9 TCF. This is divided into the currently producing northern area which was left unchanged at 4.9 TCF and the rest of the area which has had recent disappointing drilling results and was reduced to 3.0 TCF (a decrease of 10.9 TCF). Significant Antrim gas production is presently limited to the northern portion of the basin where biogenic gas generation is related to the coincidence of fresh-water influx, reservoir fracturing, and unconformity trapping conditions.

iii. Black Warrior Basin Region Summary

The Black Warrior Basin is located in northern Alabama and Mississippi. The Pottsville coal bed methane play is the most significant current producer and future gas resource. The Black Warrior Basin has produced 2.6 TCF and has remaining proved reserves of 1.3 TCF.

The NPC assessed 5.9 TCF of undiscovered potential for the Black Warrior Basin with 1.4 of that conventional and 4.5 TCF of CBM. The NPC CBM assessment of 4.5 TCF is slightly lower than the USGS 2002 assessment of 7 TCF due to lower average EUR per well. The NPC agreed with the USGS assessment for undiscovered conventional gas resource.

3. References

Gautier, D. L. and others (eds), 1996. National Assessment of United States Oil and Gas Resources - Results, Methodology, and Supporting Data. United States Geological Survey Digital Data Series DDS-30, one CD-ROM, release 2.

Hatch, J.R. and others, 2003. Assessment of Undiscovered Oil and Gas resources of the Black

Warrior Basin Province, 2002. United States Geological Survey Fact Sheet FS-038-03: 2p.

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L. Western Canada Sedimentary Basin Super-Region

1. Super-Region Summary

The 2001 Canadian Gas Potential Committee (CGPC) assessment formed the basis for the NPC assessment of the Western Canada Sedimentary Basin (WCSB) (Figure S2-56). The NPC has assessed WCSB undiscovered gas potential to be 138.4 TCF, an increase of about 57 TCF over the CGPC estimate. This includes an increase in conventional gas of 11 TCF due to successful extensions of plays into British Columbia and 30 TCF of coal bed methane and 17 TCF of shale gas which were not assessed by the CGPC.

Total remaining technical resource is 223.4 TCF and cumulative production has been 126.0 TCF.

WCSB will remain the main Canadian producing region for the foreseeable future due to existing infrastructure and high undiscovered potential. Conventional undiscovered gas is mostly in small Cretaceous pools. The Foothills and Devonian plays have the largest undiscovered pool sizes but are technologically challenging. The high gas well decline rates means large numbers of wells are needed annually to maintain current production.

Nonconventional gas resources have large potential but generally have not been assessed because they are in an early stage of commercial development or undeveloped. In the WCSB coal bed methane estimates range from 75 to 530 TCF GIP with the NPC consensus being 30 TCF recoverable gas. The NPC estimates 17 TCF of recoverable shale gas. The commercial viability of nonconventional gas is dependent on gas price (Encana estimates at least U.S. $3.50 per MCF needed), drilling and completion technology, favorable geology

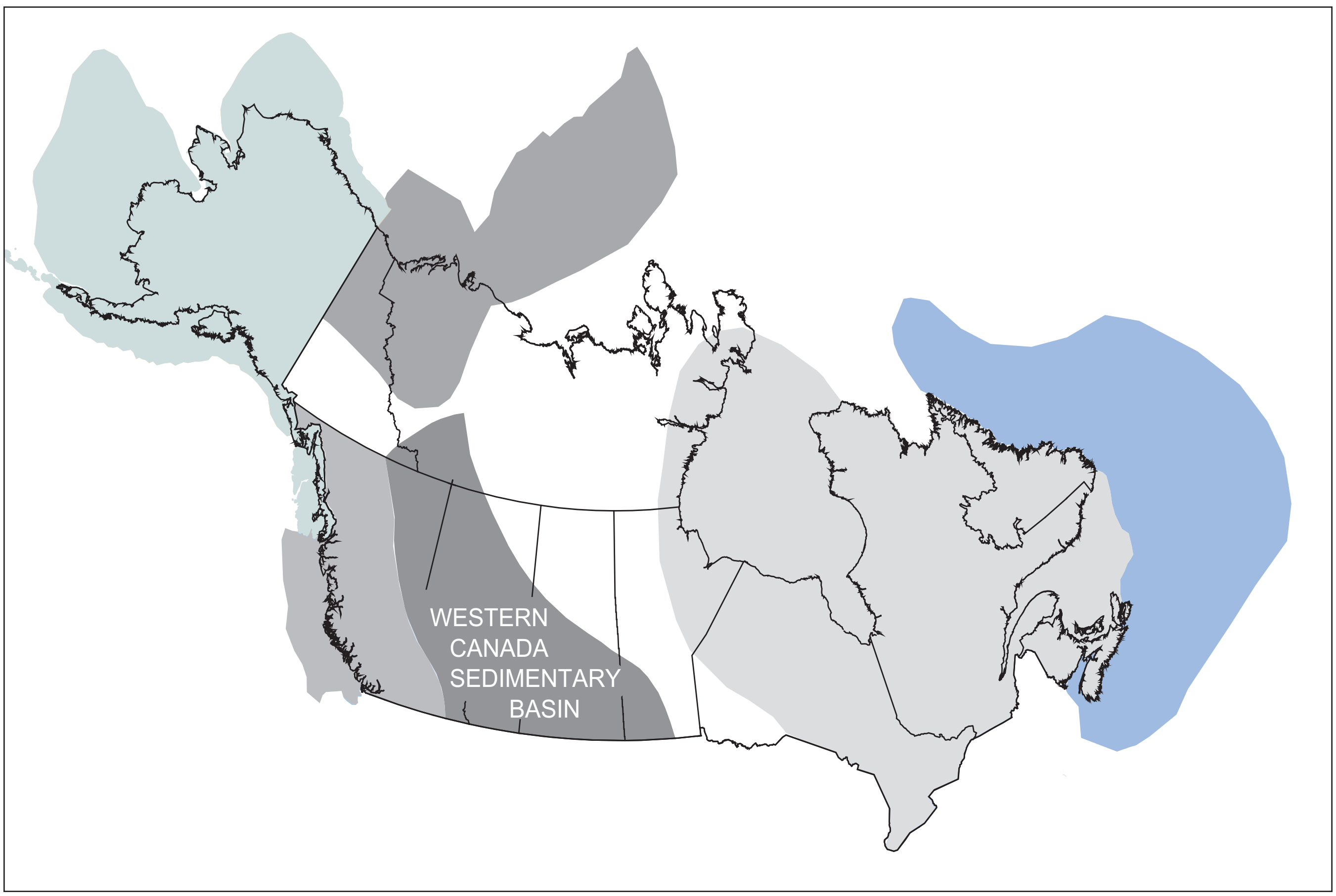


Figure S2-56. Location of the WCSB Super-Region identification, access to large land holdings, and efficient/low cost operations.

In the reactive Path outlook, production will plateau at the current level of 5.3 TCF/year for a few years and then decline through 2025 (Figure S2-57). Drilling activity will decrease from about 9,000 wells/year to about 6,000 wells/year and then start to increase in 2018 as lower productivity wells become economic.

2. WCSB Super-Play Summary

There are several key findings from the CGPC 2001 report regarding the WCSB. A total of 84 established plays were assessed with the Foothills, Cretaceous and Devonian plays combining for over 90% of undiscovered gas (Table S2-8). The WCSB plays were grouped into 8 super-plays: Foothills, Middle Devonian, Upper Devonian, Permian/Carboniferous, Triassic, Paleozoic & Jurassic Subcrop, Lower Cretaceous, and Upper Cretaceous (Figure S2-58). The CGPC uses pools rather than fields in their assessments except for the Foothills. The CGPC methodology considers gas only and does not assess undiscovered oil.

WCSB Super-Play	CGPC 2001 (TCF)	NPC 2003 (TCF)
Foothills	14.2	16.9
Middle Devonian	5.7	7.0
Upper Devonian	4.9	13.6
Permo-Carboniferous	2.1	2.3
Triassic	3.4	3.6
Paleozoic/Jurassic Subcrop	2.8	2.8
Lower Cretaceous	43.2	42.7
Upper Cretaceous	3.7	3.6
Total	**80.1**	**92.6**

Note: NPC values include 5.5% added to represent lease and plant gas.

Table S2-8. WCSB Undiscovered Conventional Gas – Comparison of NPC and CGPC

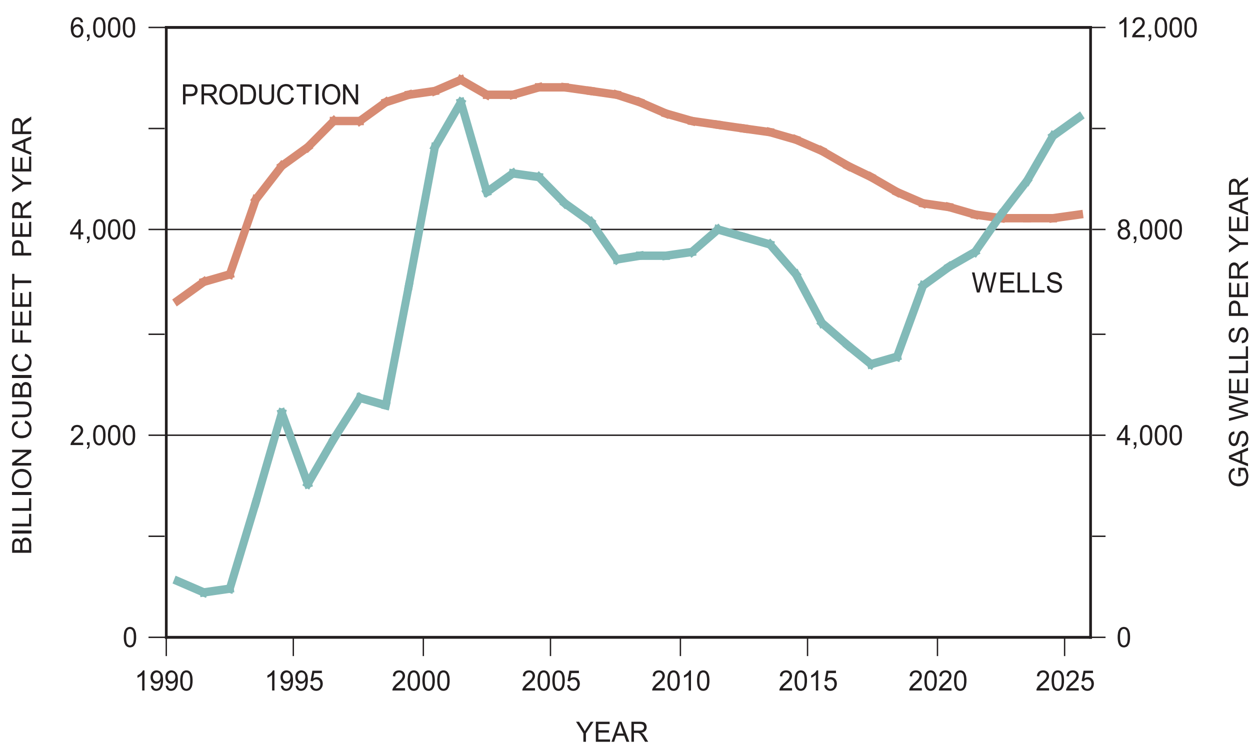


Figure S2-57. WCSB Production and Drilling Forecast

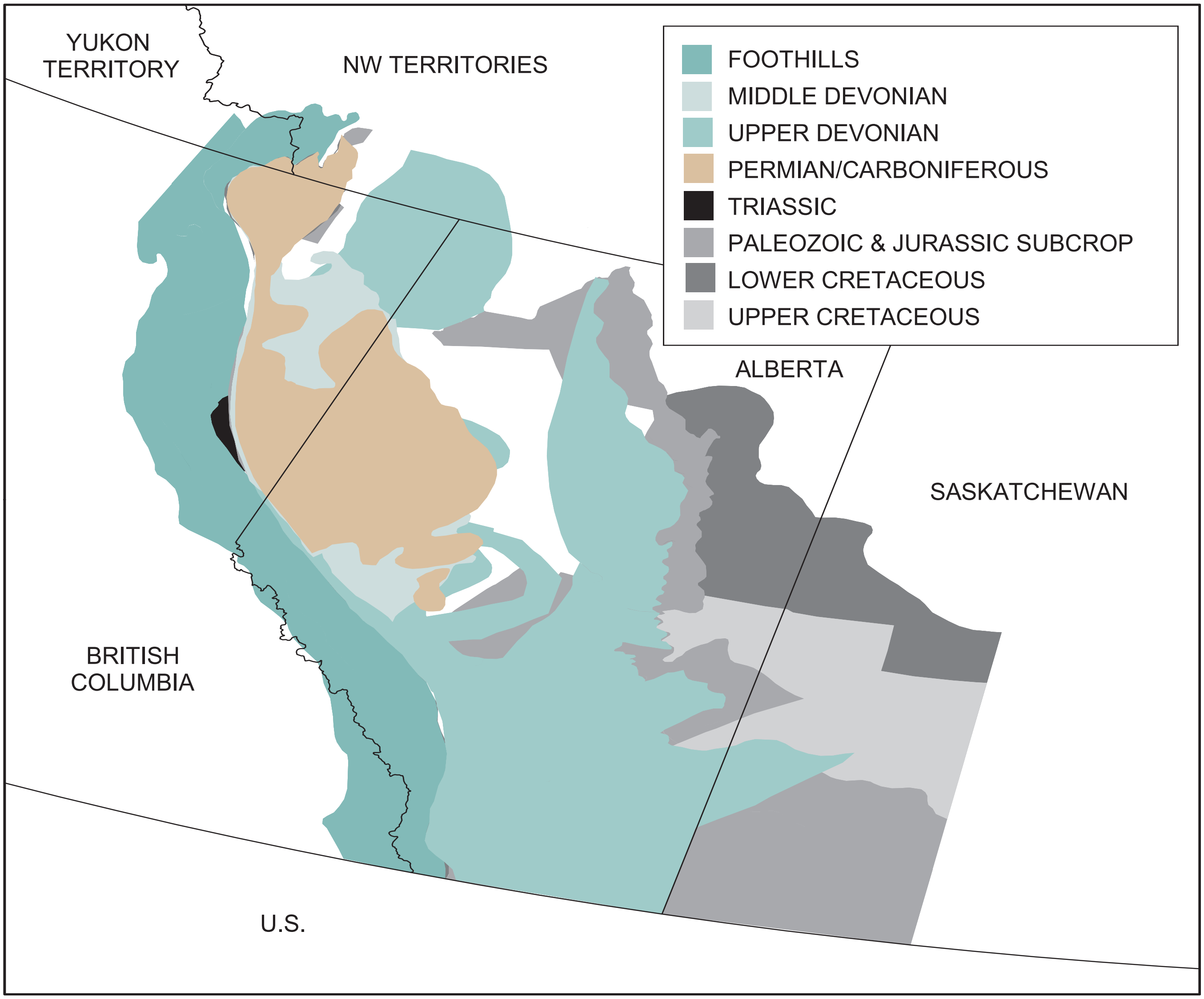


Figure S2-58. WCSB Conventional Super-Plays

There have been almost 29,000 gas pools discovered and the CGPC estimates about 203,000 undiscovered pools remain. The number of undiscovered pools smaller than 2.5 BCF is likely underestimated.

3. WCSB Assessment Description

a. Remaining Gas Reserves

There have been nearly 29,000 pools discovered in the WCSB. These pools have produced over 126 TCF and there is 57.5 TCF of remaining gas reserves.

b. Growth of Existing Fields

In the U.S. growth of existing fields is an important addition to the resource base over time. The reasons that is the case is that assessments are done at the field level and most growth to known studies use proved reserves as the basis or "known."

In Canada the methodology is different which results in less growth to known compared to the U.S. The CGPC 2001 assessment is based on pools and a calculation of initial gas-in-place of these pools. The pool level assessment removes the portion of growth related to fields which can have new pool discoveries over time. In Canada, these new pool discoveries are treated as new and separate entities. The calculation of initial gas-in-place is an attempt to characterize the full size of the pool and not just the proved portion. Again this minimizes the growth that is seen as other categories of reserves are transferred over time into the proved category. Another factor which is unique to the WCSB is that much of the undiscovered resource base is in very small pools, particularly in the Cretaceous. A large percentage of these are smaller than 1 BCF GIP and would essentially be produced with a single well. This basically eliminates the possibility of growth from additional wells due to change in well spacing or pool extensions.

The total future growth in the WCSB is estimated to be 7.4 TCF of recoverable gas by the CGPC. Cohort analysis by the NPC estimated growth in the WCSB to be about 45 TCF. Because of these widely differing results, a mid-range estimate of 28.1 TCF was adopted by the NPC for WCSB growth.

c. Undiscovered Fields Background Studies

The 2001 CGPC assessment formed the basis for the NPC supply model of the WCSB. The CGPC study was selected by the NPC because it was considered to be the most detailed and recent study that covers all of Canada. The study is available for purchase and can be found at the CGPC website (http://canadiangaspotential.com /report2.html).

Other studies were used for comparison purposes. An assessment by the USGS in 2000 was also referred to and USGS representatives attended the NPC workshop. The USGS assessment covered what they referred to as the Alberta Basin and the Canadian Williston Basin (http://greenwood.cr.usgs.gov/energy /WorldEnergy/DDS-60/). An excellent overview of Canada hydrocarbon production and future potential is "Petroleum Resources of Canada in the Twenty-first Century" by K. Skipper in AAPG Memoir 74, Petroleum Provinces of the Twenty-first Century, 2001 (http://datacorp.petris.com/specpubs/memoir74 /m74ch08/images/m74ch08.pdf).

d. Undiscovered Fields Results

The CGPC assessed a total of 84 plays in WCSB. The NPC combined those plays into eight groups of similar age and/or structural styles which are referred to as superplays: Foothills, Middle Devonian, Upper Devonian, Permo-Carboniferous, Triassic, Paleozoic-Jurassic subcrop, Lower Cretaceous, and Upper Cretaceous.

i. WCSB Foothills

The Foothills super-play is a linear trend of contractional deformation 1000 kilometers in length which parallels the east side of the Canadian Rocky Mountains from the U.S. border at Waterton to the southern District of Mackenzie in the NWT. In the south, the principal reservoirs are Mississippian carbonates and Cretaceous clastics while to the north Devonian and Triassic age reservoirs also become prospective. Porosity is generally low due to deep burial before uplift and good productivity depends on natural fractures induced by folding during uplift and structuring. In spite of more than 100 years of exploration in this trend there is still significant undiscovered gas potential because of difficult exploration due to complex geology and accessibility. Traps are difficult to image with seismic data, reservoir presence is uncertain, drilling is expensive. and much of the gas is sour. In the Foothills trend the CGPC recognized 12 plays. Eight of these are proven while four plays are conceptual and were not assessed. The eight proven plays are defined by Province (British Columbia or Alberta) and 4 structural styles: simple thrust sheets, stacked thrust sheets, tight folds, or triangle zone.

In Alberta Foothills targets are mainly Mississippian and Devonian carbonates. The Mississippian play is relatively mature but the Devonian play is still developing. Industry is using 3-D seismic and horizontal wells to explore for untested thrust sheets. Approximately 40% of the play is inaccessible in Alberta being covered by Park lands. There are 24 discoveries with the largest being about 4.6 TCF GIP. The CGPC estimated 76 undiscovered pools with the largest being 1.5 TCF GIP. The Top 4 plays are AF14 (10.1 TCF GIP), AF15 (6.9 TCF GIP), AFTZ (3.1 TCF GIP), and LFP1 (2.8 TCF GIP). In the NPC workshop CGPC representatives stated that the number of small undiscovered fields may be underestimated.

NPC workshop participants felt that British Columbia future gas potential is underestimated by the CGPC assessment. There have been recent discoveries in a Permian play that was not included in the CGPC assessment. Drilling in BC has brought the total number of wells drilled from 200 at the end of 1992 up to 800 wells in 2002. Production has doubled from 1992 to 2002 (~ 140 BCF of cumulative gas produced). The discovery rate in BC is not limited by geology but rather by gas plant capacity at Pine Creek and limited accessibility north of Pine River Valley (native claims) and north of Williston Lake (protected areas).

NPC consensus was to increase BC gas potential (BTGA play) to 5 TCF GIP (up 2.3 TCF) and accept Alberta unchanged. The largest undiscovered field is 1 TCF GIP. Average well depth is 3500 meters in the BTGA play and about 10 to 20% is not accessible.

ii. WCSB Foreland Basin Plays

The Alberta Plains and adjacent Provinces cover an extensive foreland basin which has a large number and variety of plays which generally overlie one another. The 76 conventional established plays of the CGPC were grouped into seven "super plays" for the NPC study. These plays extend from the Foothill folds on the west to the sediment onlap onto crystalline rocks of the Precambrian Canadian Shield to the east. To the north, the basin begins where sediments onlap the east-west trending Tathlina Arch in the District of Mackenzie, NWT, and stretches southward across Alberta into the United States.

Sediments range in age from earliest Paleozoic to Cenozoic in age and are up to 6000 meters thick just east of the Foothills. The two major sedimentary packages are the Paleozoic to early Mesozoic which is dominated by marine carbonate rocks and the late Mesozoic to Cenozoic which consists mainly of clastics.

Important plays in the basin include Devonian reefs, Triassic and Permian carbonates in British Columbia, Carboniferous subcrop plays below the pre-Jurassic unconformity, and stratigraphic Jurassic and Cretaceous clastics plays.

WCSB Middle Devonian. The Middle Devonian super-play contains four plays that were assessed by the CGPC: Clastics, Keg River, Swan Hills, and Slave Point. The play has 50 years of discovery history in the WCSB, with an average of 0.5 TCF GIP discovered per year for the last 20 years. There are 1500 discovered pools in these four plays and the CGPC assessed 11 TCF GIP in 2300 future pools. Approximately half of the Middle Devonian potential is in the Swan Hills.

The NPC considered the Slave Point play to be under-assessed by the CGPC due to the successful extension of the play into British Columbia. The CGPC assessed the play to have 1 TCF GIP of undiscovered gas with the largest pool expected to be no more than 300 BCF GIP. The Ladyfern discovery, which was drilled since the CGPC assessment, found 600-1300 BCF GIP. The BC Government believes the play holds a future potential of 6-7 TCF GIP. The drilling density and exploration maturity in BC is far lower than in Alberta, in part due to seismic imaging difficulties.

The NPC consensus is 3 TCF GIP undiscovered potential for this play (increase of 2 TCF).

WCSB Upper Devonian. The Upper Devonian super-play contains four plays that were assessed by the CGPC: the Wabamum, Jean Marie, Nisku, and Leduc. The first Devonian reef discovery in the WCSB was made in 1947 in the Leduc. There are 640 pools discovered in these four plays and the CGPC assessed undiscovered gas of 10 TCF GIP in 1300 pools.

The NPC considered Leduc play potential to be overestimated by the CGPC. It holds about half of the assessment for this play group. About one half of the assessed Leduc potential is sub-thrust in deep, high cost, structurally complex traps which are difficult to image on seismic, difficult to access and contain sour gas.

The NPC considered the Jean Marie play potential to be underestimated in the CGPC assessment. The CGPC assessed a future potential of only 0.65 TCF GIP while Encana has recently announced it has found 5 TCF GIP (3 TCF recoverable). The play, discovered 30 years ago, is described as a gas saturated, underpressured carbonate. Many wells looking for deeper targets have penetrated this play and it is behind pipe. New information suggests the play is nonconventional, with widespread gas saturation in a north-south trending reef complex and an area of carbonate mud mounds and patch reefs to the east. Carbonate bank edge porosity is reportedly detectable on seismic and Encana has focussed its development efforts in this area. The total play area may be as large as 20,000 square miles. Initial production (IP) from wells averages 2-3 MCFD and reserves are about 4-5 BCF/well. The formation is easily damaged, but horizontal wells, under-balanced drilling, and some acid stimulation are being utilized. The NPC consensus was to increase the CGPC assessment to 8 TCF GIP (4 TCF recoverable). This is an increase of 7.35 TCF GIP.

WCSB Cretaceous. The Upper and Lower Cretaceous super-plays contain 11 proven and 1 conceptual play assessed by the CGPC. The most important of these plays are the Upper and Lower Mannville (E136, E166) sandstones. They account for 50% of the discovered gas reserve (Upper 33.5%, Lower 16.1%) and 38% of the undiscovered resource potential (Upper 21.4%, Lower 16.7%). The undiscovered resource potential is large, 66 TCF GIP (43 TCF nominal marketable), which accounts for 54% of the future WCSB gas potential, but nearly half is in pools smaller than 1 BCF GIP. Comparison of 1996 vs. 1988 discoveries shows smaller pools, lower initial rates (0.8 MCFD vs. 1.0 MCFD), and faster decline rates (32% vs.

19%). During the last 10 years, 68,000 wells (18,000 exploratory) have targeted the Lower Cretaceous and 12 TCF GIP was discovered in 6,650 pools.

Many of these "discoveries" were recompletions and many were targeting oil. It is estimated that 1 million wells would be needed to discover all the pools in these two plays. To date, 380,000 (110,000 exploratory) wells have been drilled in the WCSB with an historical success rate of about 30%. NPC consensus accepted the CGPC assessments unchanged with 21 TCF GIP in the Upper Mannville and 17 TCF GIP in the Lower Mannville. The estimated size of many discovered pools in the Cretaceous have been reduced because prior estimates were based on an overly optimistic drainage area. This suggests that growth to known may be minimal or absent for many of these pools.

iii. WCSB Exploration Issues

A number of issues affect WCSB exploration, the most significant of which is shallow versus deep gas exploration. It is much more economic to drill shallow targets, yet these are at a very mature stage of exploration. Shallow wells cost about $0.1-0.5M, versus $2-10M for deep wells, and usually require only a few weeks to connect to gas plants and the transportation network. Deep gas potential is often sour (especially in the Devonian) and characterized by generally much longer cycle time due largely to H_2S regulation, extensive landowner consultation, and competition for access to gas plants. Additionally, there are several environmental access issues in the Foothills where most of the deep potential is located. There is effectively a royalty "penalty" on deep gas because operators must pay top royalty rates due to high well deliverabilities. A royalty holiday is available but is not effective because its impact is reduced by longer cycle time. Shallow producers' economic decisions are often based on quick pay-out rather than full cycle rate of return. Industry mergers of recent years have resulted in fewer companies with large capital ("staying power") and technical knowledge of deep gas potential which has led to reduced deep gas drilling levels.

iv. WCSB Nonconventional Resources

Coal Bed Methane. Over 350 wells have been drilled that specifically targeted coal bed methane in Canada and ~ C$200M has been spent, but there has been little coal bed methane (CBM) production to date. Early wells tested high rank coals, but they had low permeability and very low rates, if any gas flow at all. Low permeability, plastically deformed coals in the Foothills, and inadequate completion technology are blamed for failures. More recent attempts to develop CBM have targeted shallow, low-rank coals, similar to those being developed in the Powder River Basin of the United States.

There are numerous coal zones in the WCSB ranging in age from Jurassic (Fernie), through the Cretaceous (Mannville, Belly River, Edmonton, Scollard) and into the Tertiary (Ardley). More than 100,000 wells completely penetrate the coal bearing sections so the location of the coal is well known. The key to success is to locate areas of favorable permeability, good coal gas content, low water production, large land tracts with hydrocarbon rights, and to minimize drilling and completion costs.

There are several technical obstacles to successful development of CBM in the WCSB. Shallow coals are low rank with relatively lower gas content and produce water with the gas (though, notably, the Encana/MGV's Palliser project, the first commercial CBM development in the WCSB, has very low water production). Deeper coals are higher rank with higher gas content, but have lower permeability and risk for high CO_2 content. The Canadian public domain well database lacks permeability and gas capacity data which makes accurate GIP estimates difficult. CBM water quality in WCSB is variable. Some isotope analyses have been conducted which indicate that some CBM water is very old and coals are not being recharged. The Alberta Energy and Utilities Board (AEUB) plans to make CBM data available to the public domain in the near future. Low cost drilling & completions are also necessary for successful CBM development. Almost all of the Canadian CBM activity to date has targeted coals shallower than 1,200 meters depth.

Non-technical challenges slowing CBM development include land access, ownership rights to CBM, lack of tax incentives (as the U.S. had to spur early CBM development), rig availability for potentially very large numbers of wells, and the immature regulatory environment. Presently, the AEUB and Alberta environmental regulatory agencies have different water disposal regulations.

The WCSB nonconventional gas resource is poorly understood and there is a wide range of uncertainty about the potential size of the CBM resource. The Geological survey of Canada (GSC) estimates 115 to

352 TCF GIP for the Alberta Plains. The CGPC 2001 used the GSC number for the Plains and reports additional potential from 60-179 TCF GIP for the Alberta and BC Foothills. A 1999 National Energy Board (NEB) study estimates 75 TCF. In 1992 the AEUB estimated 250 TCF. David Hughes of the GSC has estimated 215-669 TCF GIP shallower than 1,200 meters depth. Energy and Environmental Analysis, Inc. (EEA) estimates 95 TCF technically recoverable combined in all coal zones. The Alberta Geological Survey estimates 500 TCF GIP for the Alberta Plains which includes 320 TCF GIP for the Mannville coals.

An NPC workshop was held in Calgary in March 2003 to discuss Canadian nonconventional resource potential including CBM. It was decided that maps by David Hughes (not yet published) of thickness, depth, and gas content of individual coal beds in Alberta will be the basis for the NPC assessment. It was agreed that three major coal zones, the Horseshoe Canyon, Mannville, and Ardley, would be assessed. The developable portion of each zone is estimated to be where maps indicate GIP > 2 BCF per section. Coals in the Horseshoe Canyon are dry coals and analogous to the coals of the Raton Basin in the United States. The Raton coals are developed on a 320 acre spacing and have an average well recovery of 0.8 BCF. It was assumed that about 50% of the area above the GIP cut-off could be technically developed. Coals in the Mannville contain brine and are analogous to the San Juan Basin non-fairway coals. These coals are developed on a 100 acre spacing and recovery averages about 0.6 BCF per well. It was assumed that about 20% of the area above the GIP cut-off could be technically developed. Coals in the Ardley are thick, shallow and analogous to coals in the Powder River Basin. These coals are developed on an 80 acre spacing and recovery averages 0.4 BCF per well. It was assumed that about 10% of the area above the GIP cut-off could be technically developed. Calculations using this process result in a total of 30 TCF of technically recoverable gas. Over half of this is from the Horseshoe Canyon zone (18.2 TCF). The NPC total is similar to the MGV Resources assessment of 22 TCF recoverable. For costing purposes, it was assumed that any water produced would be re-injected.

The NPC workshop also discussed CBM development timing. In Canada, the technically best CBM resources are not necessarily being developed first because existing infrastructure and land issues are controlling current development plans. CBM close to infrastructure with associated low development costs will be developed first. The NPC assumes first WCSB CBM production from the Plains in 2002 while first production from the Foothills is assumed to be about 2008. Curtis Brown (AEUB) reported that CBM regulations are close to being released. A CBM Administration Zone will be defined as "all coal seams within a formation unless separated by more than 30m of non-coal bearing strata."

Shale Gas. The basis for the NPC shale gas assessment is a GTI 2002 study of Western Alberta and Eastern British Columbia (GRI contract # 8365). The five formations assessed are the Cretaceous Wilrich and equivalents, the Triassic Doig, Doig Phosphate, Montney and Devonian Ireton/Duvernay. Estimated GIP for the 5 formations is 860 TCF. Some additional zones with potential, but not assessed by GTI, include Cretaceous Lea Park, Joli Fou, Colorado, First White Specks/ Mannville shales, Jurassic Poker Chip/ Fernie shales, Mississippian Banff, Devonian Exshaw, and Devonian Keg River shales. Technical and non-technical issues for assessing resource potential are similar to CBM. These include a lack of production test data, need for natural fractures, water handling issues, need for large, continuous land blocks, and an immature regulatory environment.

The NPC concluded that no more than 10% of the GTI assessment of in-place resource would be developable. It was also agreed that within the developable area a 20% recovery factor might be reasonable. This results in an NPC assessment of 17 TCF of recoverable shale gas. The New Albany Shale of the U.S. Appalachian region was selected as the best producing analog for estimating appropriate well spacing and well recoveries. The NPC will use 80 acre spacing and 0.2 BCF/well for economic modeling.

Tight Gas. The WCSB has many potential tight gas zones, especially on the western, deeply buried side of the basin, where up to 4 km of section has been removed since early Tertiary times. Basin Center tight gas development is seen as a major gas growth area by many large independents including Anadarko, Burlington, and Devon. Major pipelines, which were full until about 1995, now have available capacity due to the construction of the Alliance pipeline and expansion of the Trans Canada Pipeline system a few years ago. Units with tight gas potential include the Cretaceous Edmonton, Belly River, Milk River, Medicine Hat, Second White Specks, Viking, Mannville, Jurassic Rock Creek, Triassic Doig, Montney, and Mississippian Bakken sands. Many of these units have both a conventional and a nonconventional component.

Western Canada may not have the same potential for tight or basin centered gas as seen in the US Rocky Mountain or Gulf Coast regions. Numerous wells have already drilled through the potential tight gas zones and there is a question about how much "deep basin centered gas" might have been encountered. WCSB basin center developments to date have largely been in "sweet spot" areas, such as the Elmworth field, and little effort has been made to commercialize associated poorer quality, lower grade basin center gas. In the WCSB, deep basin gas is generally in small pools with low GIP per unit area because only a few, thin reservoir sands are generally present. There is very little public data for assessing deep basin centered gas, such as detailed information on well fracture stimulations. Canada does not have a regulatory definition of tight gas as the U.S. has, which was developed to administer tax incentives. There are no current plans by the AEUB to develop a tight gas definition; all gas is treated alike.

The CGPC assessment does not distinguish between conventional and tight gas. The CGPC includes nearly 100,000 pools in Cretaceous plays, which hold much of the basin's tight gas. The NPC workshop participants agreed that the tight gas potential in WCSB is largely captured in the conventional plays assessed by the CGPC. The NPC must assign accurate costs to tight gas wells as completions are expensive and gas flow rates are generally low. Historically 50% of WCSB gas wells are stimulated and these gas wells account for roughly 25% of new gas production. The NPC will apply these percentages to the CGPC's Cretaceous resource assessments for well completion costs.

4. Comparison of Recent Canadian WCSB Assessments

Several studies describing the resource potential of the Western Canada Sedimentary Basin have recently been published. These include assessments made by the National Energy Board, Canadian Energy Research Institute, and the Alberta Energy and Utilities Board (assessed Alberta only). The results are of similar magnitude for conventional resources. Assessed undiscovered recoverable gas volumes are shown in Table S2-9. The NPC 2003 assessment of total resources falls near the middle of the range published by other studies. The NPC assessment of CBM is conservative compared to CERI and the NEB.

a. National Energy Board (NEB)

The NEB assessed two scenarios. The "Supply Push" scenario assumes current technology. In "Technovert" a higher resource estimate is made, reflecting future technology advances that are expected to lead to more effective exploration and development techniques that will result in larger volumes being discovered and recovered. The differences in volume between the two scenarios are largely due to uncertainty of the potential in British Columbia. Resources grow in Alberta with improved technology, but growth is proportionately higher in BC. Conventional resources are similar to NPC, but CBM estimates are much higher.

Assessment	Conventional (TCF)	Coal Bed Methane (TCF)	Total (TCF)
NPC 2003	93	30	123
CGPC 2001	80	NA	80
NEB 2003 Supply Push	71	60	131
NEB 2003 Technovert	99	80	179
Ceri 2003 "Alternate" Case	84	215*	299
AEUB 2003 (Alberta only)	34	NA	34

* Alberta Plains region only.

Table S2-9. WCSB Assessment Comparison

b. Canadian Energy Research Institute (CERI)

The CERI study incorporates two scenarios to model supply and demand and predict future productivity. One scenario uses the CGPC assessment results. For the second scenario, CERI commissioned a study to define an alternate, optimistic estimate of Canada's gas resources that would "reflect the uncertainty in resource assessments and because the CGPC resource estimate excludes volumes for a number of areas thought to have reasonable prospects for natural gas discoveries." The CGPC describes a number of theoretical plays for which data was insufficient or level of risk deemed too high for the committee to perform a quantitative assessment. The "Alternate" scenario was constructed to "provide a credible upper bound estimate of resources." This case draws from CGPC theoretical plays, the Geological Survey of Canada, and other published information. The "Alternate" case also assesses volumes for coal bed methane. It does not include shale gas or gas hydrate.

As Table S2-9 shows, the increase in conventional gas resources above the CGPC estimate is modest, and only slightly larger than the NPC estimate, which also adjusted the CGPC estimate upwards. The increase in the CERI estimate, like the NPC estimate, is attributable largely to the northwestern part of the WCSB as play trends continue in to British Columbia. The CERI study assesses a very large volume for CBM. The CGPC did not assess CBM. The NPC assessment is considerably less than the CERI estimate. The wide variance in these estimates reflects the large uncertainty regarding technically recoverable CBM.

c. Alberta Energy and Utilities Board (AEUB)

The AEUB assessment is confined to Alberta only. The AEUB is very conservative compared to the others even considering it was for Alberta only. The AEUB made no assessment for CBM.

d. Implications for the Model Forecasts

For conventional resources, all of the recently published assessments of undiscovered gas are similar with the exception of AEUB which is significantly lower. All recognize that few large accumulations are likely to remain, particularly in Alberta, and that remaining resources will generally be found in increasingly smaller pools. Further, each study recognizes that the number of wells required to maintain or slow decline from current production levels will have to increase year to year as the average pool size becomes smaller. In addition, each study concludes that production levels from conventional resources are likely to decline from historical levels sometime in this decade.

The NEB deliverability models suggest production can be sustained until about 2008. After that production declines rapidly. In the NEB model, CBM only delays decline for a few years.

The CERI model suggests that productive capacity can be maintained at or slightly above current levels until 2010. This assumes that gas drilling increases from 2002 levels of 8,000 wells each year to 15,000 wells each year. If drilling remains at 8,000 wells each year rapid production decline begins in 2005. The increased resource assessment associated with the "alternate" case shows an increase in production until 2010 followed by rapid decline and production dropping below current levels by 2015. CERI also states that prices will need to remain above $C4/MCF for these predictions to be reasonable. The NPC study, like the others, sees some increase in the resource assessment above the CGPC assessment from British Columbia, but views the CERI "alternate" case as optimistic.

The AEUB assessment covers only Alberta, but as Table S2-9 shows, the assessment is the most pessimistic and, if correct, decline in productivity would likely happen sooner than predicted by either the NEB or CERI. The AEUB predicts peak production in 2003 with decline beginning in 2004. Like CERI, the AEUB predicts an increasing number of wells will be required each year simply to slow the pace of decline.

CBM resources are highly uncertain at present. There is a broad variance in the resource assessments made by other individuals and groups. The NPC study is generally more conservative than other published estimates. There are also likely to be some resources associated with shale gas for which the NPC has assessed a modest resource. For the current production level of the WCSB to be maintained beyond 2010 nonconventional gas development will have to be more successful than previous attempts.

M. British Columbia Super-Region

1. Super-Region Summary

The 2001 CGPC assessment provided the basis for the NPC's assessment of British Columbia (Figure S2-59). The portion of British Columbia which is part

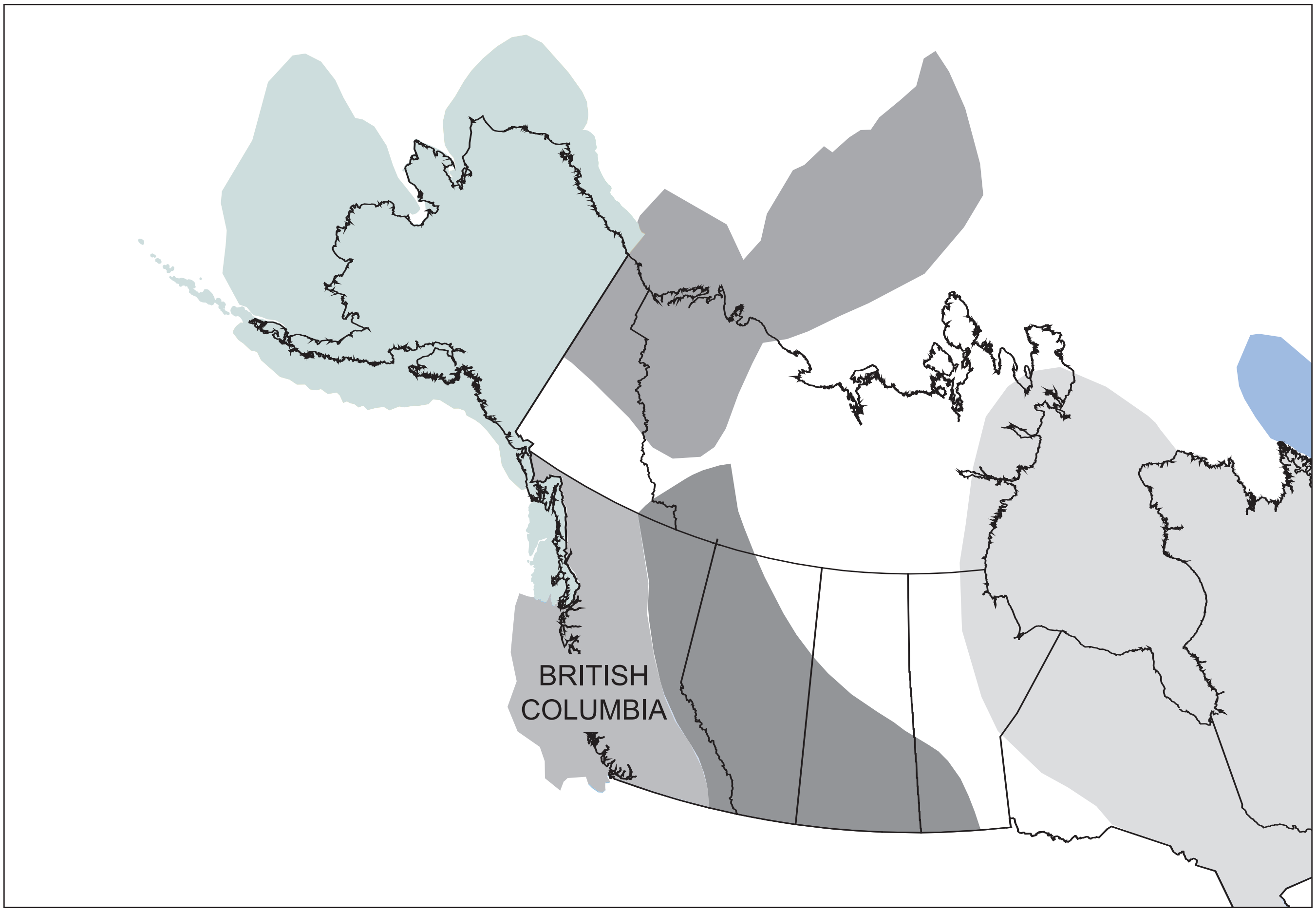


Figure S2-59. Location of the British Columbia Super-Region

of the Western Canada Sedimentary Basin is not included here but with the WCSB super-region. British Columbia is divided into a series of offshore basins and intermontane interior basins (Figure S2-60). The offshore basins have the best gas potential and were assessed by the CGPC. The interior basins were described but not assessed due to their high risk and low potential.

Total remaining technical resource is 10.9 TCF and there has been no production.

There have been no significant discoveries to date from this portion of British Columbia. The NPC accepted without modification the CGPC assessment of undiscovered gas of 13.7 TCF GIP (10.9 TCF recoverable).

The offshore basins have been under moratorium to exploration since 1972. The provincial government is discussing opening this area to exploration again.

2. British Columbia Assessment Description

a. Remaining Gas Reserves

There have been no significant discoveries from this portion of British Columbia. There was minor Pleistocene gas production from onshore coastal British Columbia near Vancouver, B.C. but these fields have been abandoned.

b. Growth of Existing Fields

There are no producing fields in this portion of British Columbia and no proven plays. Growth to known only occurs as fields are developed and produce over time. There are no significant discoveries in this portion of British Columbia and thus no growth has been assigned.

c. Undiscovered Fields Background Studies

The 2001 CGPC assessment formed the basis for the NPC supply model of British Columbia. The CGPC study was selected by the NPC because it was

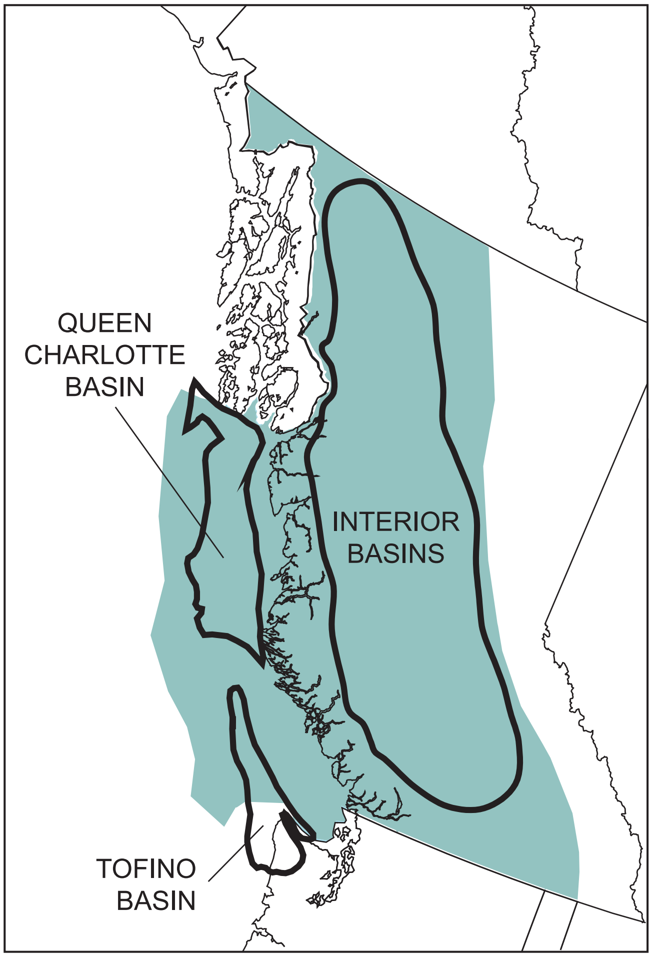


Figure S2-60. British Columbia Major Geologic Basins

considered to be the most detailed and recent study that covers all of Canada. The study is available for purchase and can be found at the CGPC website (http://canadiangaspotential.com/report2.html).

An excellent overview of Canada hydrocarbon production and future potential is "Petroleum Resources of Canada in the Twenty-first Century" by K. Skipper in AAPG Memoir 74, Petroleum Provinces of the Twenty-first Century, 2001 (http://datacorp.petris.com/specpubs/memoir74/m74ch08/images/m74ch08.pdf).

d. Undiscovered Fields Results

The CGPC identified 13 plays in British Columbia, 7 of which were assessed and 6 plays were described but not assessed. The NPC agreed with the CGPC assessment of 13.7 TCF GIP for British Columbia but the CGPC did not publish an estimate for recoverable gas. The NPC assumed 70% recovery resulting in 9.6 TCF of recoverable gas. British Columbia is divided into two regions: Pacific Coast basins and Interior basins. The CGPC assessed the Pacific Coast basins but only described and did not assess the Interior basins.

i. Pacific Coast Basins

The Pacific coast of Canada is tectonically active associated with subduction of oceanic crust beneath North America. The coastal region, like much of western British Columbia, is made up of allochthonous terranes that were accreted to North America during the Jurassic and Cretaceous. Sediments deposited on these terranes before collision and in extensional basins formed in response to continued subduction after collision are assessed to have some hydrocarbon potential. The Queen Charlotte and Tofino Basins are the larger of the several post-collision basins.

The Queen Charlotte Basin lies between the Queen Charlotte Islands and the mainland. Triassic volcanics are overlain by marine Jurassic sandstones, shales, limestones, and siltstones. These are overlain by Cretaceous and Tertiary clastics and volcanics. The two major episodes of deformation in the late Jurassic and late Cretaceous have created several northwest-trending compressional folds that might trap hydrocarbons. Potential source intervals have been identified in the Jurassic, Cretaceous, and Tertiary, and seeps have been reported. Sandstones derived from volcanic terranes might provide reservoir, but are high risk due to burial-related degradation of reservoir quality. Eighteen wells were drilled in the 1960s and 1970s with oil staining reported in the Sockeye well and gas was reportedly flared from an onshore well in the Queen Charlotte Islands.

The Tofino Basin lies off the west coast of Vancouver Island. A thick section of Miocene to Pliocene marine mudstones, siltstones, and turbidite sands unconformably overlie deformed Tertiary and Mesozoic volcanic and sedimentary rocks. Fault related closures and shale ridges are observed that might provide traps. The principal play concept is for turbidite sands to pinch-out forming stratigraphic traps on the flanks of shale ridges. The potential for source rocks is not known and there is uncertainty about maturation and timing of any potential source. Shell Canada drilled six offshore wells in the late 1960s and encountered thin, poorly developed reservoir, but shallow gas shows might indicate source potential. The basin is considered to have a low probability for finding hydrocarbons.

The entire British Columbia offshore has been in moratorium since 1972 because of environmental concerns, Haida native claims and the need to fully define, locally, the U.S. and Canadian border. A federal provincial board would need to be established to administer any oil and gas activities. However, the current provincial government is interested in opening up this area for further exploration.

ii. Interior Basins

There are a number of basins in the interior of British Columbia which have had variable exploratory efforts. Some of these basins are undrilled. No significant discoveries have been made. These basins include the Nechako basin, Quesnel trough, Bowser basin, Sustut basin, Whitehorse trough, and Rocky Mountain trench. The CGPC has described these basins but did not assess them. The NPC agreed with the CGPC that no gas should be assigned to these basins at this time.

N. Arctic Canada Super-Play

1. Super-Region Summary

The 2001 CGPC assessment formed the basis for the NPC's assessment of Arctic Canada (Figure S2-61). There have been about 60 oil and gas fields discovered, but only two have produced (Norman Wells oil field and the small Ikhil gas field, which supplies the Inuvik community in the Mackenzie delta with gas). Discoveries have not been developed due to to the remote location, lack of infrastructure and previous resistance to oil and gas development by many native peoples. Total technical resource is 71.0 TCF and cumulative production has been only 75 BCF.

The NPC accepted without change the CGPC assessment of undiscovered gas of 51 TCF GIP (35 TCF recoverable) (Table S2-10) for larger fields but added volumes in the small field fraction for a total of 46.4 TCF recoverable. Discovered fields total 34 TCF GIP (24.6 TCF recoverable). Arctic Canada has been divided into three regions: Mackenzie Corridor, which is onshore along the Mackenzie River; Mackenzie Delta/Beaufort Sea, which is onshore and offshore near the mouth of the Mackenzie River; and Arctic Islands, which is onshore and offshore. The Arctic Islands are much more remote than the other two areas and any development there will be at a much later date (Figure S2-62).

In the Reactive Path outlook, first significant gas production from Arctic Canada will occur in 2009 (Mackenzie Gas Project) from three onshore gas fields

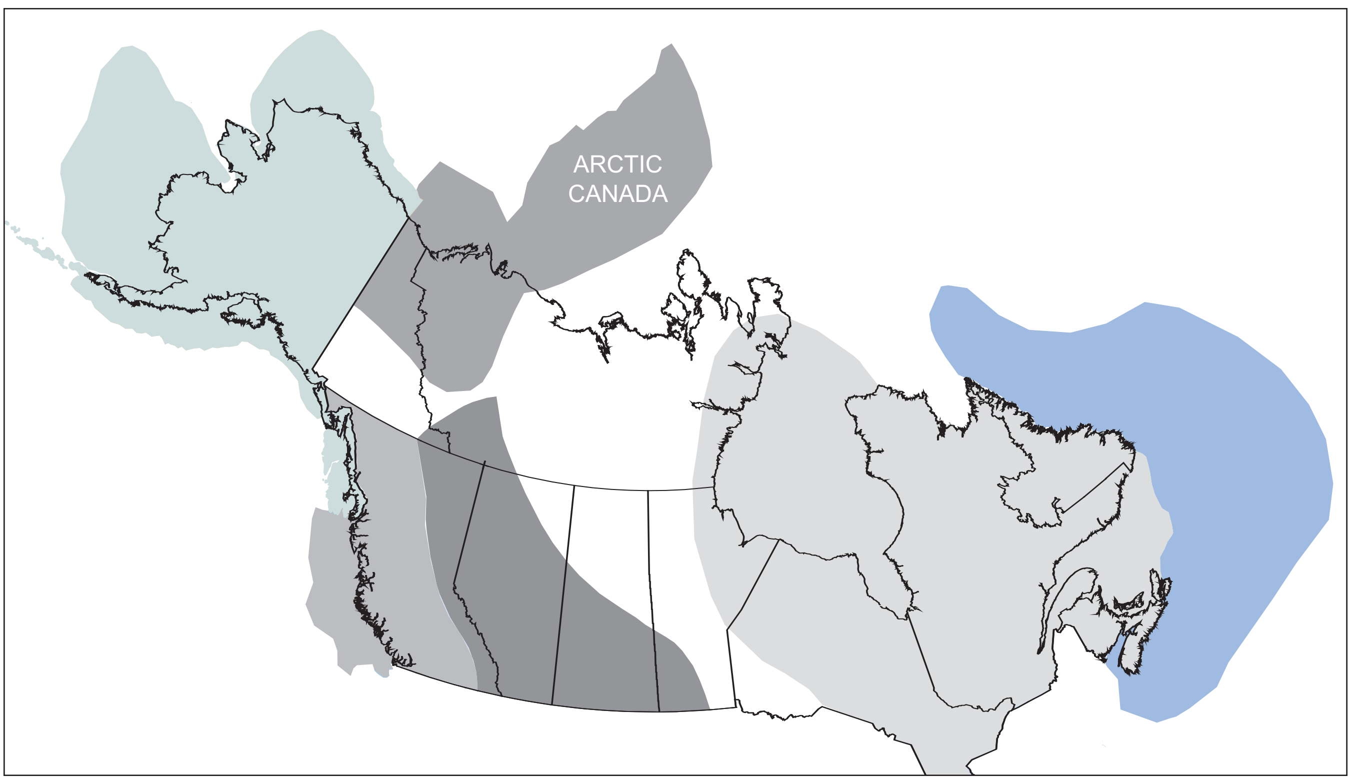


Figure S2-61. Location of the Arctic Canada Super-Region

Arctic Canada Region	CGPC Discovered Gas* GIP (Rec) (TCF)	NPC Undiscovered Gas GIP (Rec) (TCF)
Mackenzie Corridor	1.2 (00.7)	6.5 (04.6)
Mackenzie/Beaufort Sea	13.4 (08.8)	32.6 (21.1)
Arctic Islands	19.8 (16.4)	11.4 (09.4)
Total	**34.3 (25.9)**	**50.6 (35.2)**

* Canadian Gas Potential Committee, *Natural Gas Potential in Canada,* 2001.

Table S2-10. Arctic Canada Discovered and Undiscovered Gas in Larger Fields

at a rate of about 400 BCF/year (Figure S2-63). An expansion in 2016 will increase production to about 600 BCF/year. Drilling activity will increase from 10-20 wells/year through 2015 to 40-50 wells/year post 2020.

2. Arctic Canada Assessment Description

a. Remaining Gas Resources

Three Mackenzie delta gas fields: Taglu, Parsons Lake, and Niglintgak are being considered for

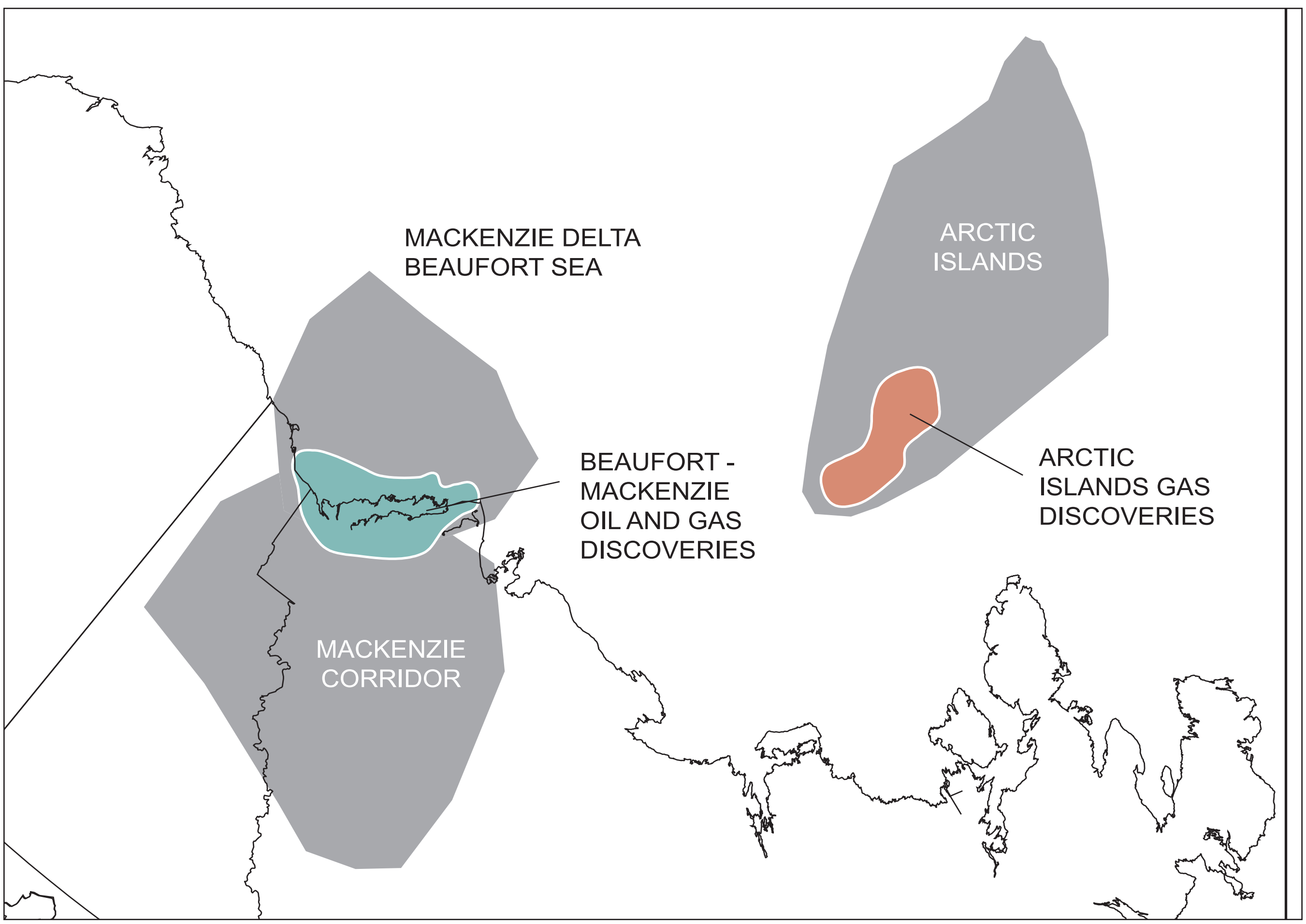


Figure S2-62. Arctic Canada Regions and Areas of Discoveries

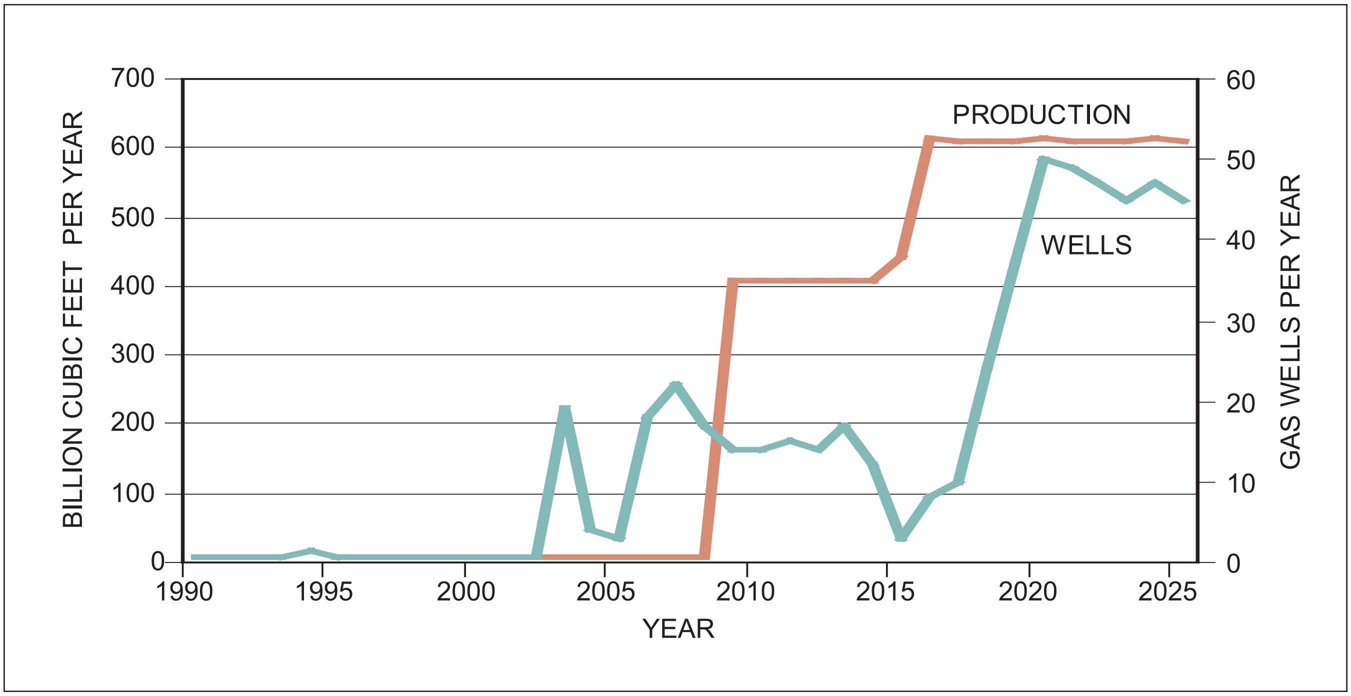


Figure S2-63. Arctic Canada Production and Drilling Forecast

development (Mackenzie Gas Project) with first production currently estimated for 2009. The CGPC reports that there is 34.3 TCF GIP (24.6 TCF recoverable gas) in Arctic Canada.

b. Growth of Existing Fields

In Arctic Canada there is currently only minor gas production to meet local needs yet major gas production is planned for 2009 (Mackenzie Gas Project). As growth to known is a process that only applies to developed and producing fields no growth to known has been assigned to Arctic Canada fields at this time.

c. Undiscovered Fields Background Studies

The 2001 CGPC assessment formed the basis for the NPC supply model of the Arctic Canada. The CGPC study was selected by the NPC because it was considered to be the most detailed and recent study that covers all of Canada. The study is available for purchase and can be found at the CGPC website (http://canadiangaspotential.com/report2.html).

An excellent overview of Canada hydrocarbon production and future potential is "Petroleum Resources of Canada in the Twenty-first Century" by K. Skipper in AAPG Memoir 74, Petroleum Provinces of the Twenty-first Century, 2001 (http://datacorp.petris.com/specpubs/memoir74/m74ch08/images/m74ch08.pdf).

d. Undiscovered Fields Results

The CGPC identified 31 plays in Arctic Canada, 14 of which were assessed and 17 conceptual plays were described but not assessed. The NPC accepted the CGPC Arctic Canada assessment without modification. Arctic Canada is divided into three major regions which are described in more detail in the following sections: Mackenzie Delta/Beaufort Sea, Arctic Islands, and Mackenzie Corridor.

i. Mackenzie Delta/Beaufort Sea

The assessment of undiscovered resources includes the onshore Mackenzie Delta, Tuk Peninsula, and offshore continental shelf, including waters west of the delta to the Canadian border with Alaska. More than 100 wells have been drilled since the 1960s and 39 oil and gas discoveries have found an estimated 13 TCF GIP (9 TCF technically recoverable). Most of the wells are drilled onshore and in the shallow waters of the Mackenzie Delta on the crests of structures. Discovered fields are not fully delineated so there is uncertainty about their size, although seismic direct hydrocarbon indicators ("bright spots") are present in some fields which can help constrain the assessment. Onshore and in shallow water many of the large structures are drilled, but there is still exploration potential for flank stratigraphic and fault dependent traps in that area. Large structures remain untested in the outer part of the Delta, deeper water, and the Western Beaufort Sea.

Drilling technologies differ in shallow water versus water depths greater than 20 meters. For exploration wells in shallow water ice islands reduce costs and extend the drilling season. In deeper water offshore, drill ships are required. For field development, offshore facilities and pipelines will need to be protected from winter ice in the Beaufort Sea.

This area is characterized by Mesozoic and Cenozoic fluvial and deltaic sands and shales deposited over Paleozoic sedimentary rocks which were faulted and subsided during mid-Mesozoic rifting. Deltaic sediments deposited as a series of seaward prograding wedges thicken to more than 12,000 meters below the shelf. Reservoir quality sanstones are present in both the post rift and pre-rift sections. Late Jurassic, Lower Cretaceous, Upper Cretaceous and Tertiary shales have been locally identified as source rocks. The four CGPC plays are based on trap style: Basin Margin, Listric Fault, Shale Anticline, and Tilted Fault Block Plays.

The Basin Margin and Listric Fault plays are located onshore and in water less than 20 meters deep. The Basin Margin Play is characterized by tilted Paleozoic fault blocks flanked by thick wedges of Jurassic and Lower Cretaceous sandstones. Oil and gas are reservoired in Cretaceous sands in fault related traps. Upper Cretaceous shale and a variably thick section of Tertiary fluvial to deltaic sediments cap these sequences. Northwards and offshore the deltaic wedge thickens and oil and gas are trapped in Tertiary sands in roll-over anticlines associated with down-to-the-basin listric faults. In both plays the large features are drilled. Undiscovered accumulations, while potentially numerous, will probably be relatively small. Three gas fields: Taglu, Parsons Lake, and Niglintgak are being considered for development (Mackenzie Gas Project) with first production currently estimated for 2009. The proposed development also provides access to the pipeline for other existing discoveries and potential results from ongoing exploration.

The Tilted Fault Block and Shale Cored Anticline plays are found further offshore and west of the delta towards the U.S. and Canadian border. These plays are far less mature and have the potential for larger undiscovered fields. There are two discoveries in the Western Beaufort Sea suggesting a working hydrocarbon system, but the discoveries are thought to be small. Due to the remote location and difficult environmental conditions only large fields will be commercial. It is unlikely that this area will supply gas before 2025.

ii. Arctic Islands

Four tectonic-stratigraphic provinces are found in the Arctic Islands region which are: the Arctic Stable Platform, Arctic Fold Belt, Sverdrup Basin, and Arctic Coastal Plain. There are 18 gas and oil discoveries which the GCPC assesses at nearly 20 TCF GIP (16 TCF technically recoverable). Four of these discoveries are larger than 1 TCF GIP and Drake Point is larger than 5 TCF GIP.

The Stable Platform is the southernmost province and lies north of the Canadian Shield and south of the south-vergent Fold Belt. The Platform is characterized by a relatively thin (< 3000 meters) Precambrian to Devonian section of shallow water carbonate rocks that is relatively undeformed. There are no reported seeps, although geochemical data suggests the Silurian may have source potential. Burial is likely insufficient for maturation and the area is not thought to be highly prospective. There may be some potential adjacent to the foldbelt where source rocks are buried deeply enough to generate hydrocarbons and where either sub-thrust structural traps or stratigraphic traps might be found.

The Fold Belt has a section of Cambrian through Devonian limestones and shales which are folded and thrusted and subsequently modified by salt movement. The folded strata display evidence of rapid facies changes where carbonate build-ups interfinger with basinal shales to the north and shelfal deposits to the south. Organic-rich shales are found in several intervals. At least fifteen wells have found no sizeable accumulations. The Winter Harbour well tested a small volume of gas from Devonian sands at the base of permafrost. In general, the wells have found fine-grained carbonates with poor reservoir properties.

Hydrocarbon discoveries are found north of the Fold Belt in the Sverdrup Basin. The Sverdrup Basin developed as a Carboniferous rift which has up to 13,000 meters of Carboniferous to Tertiary age sediments. Early sediments were carbonate rocks around the basin margin with thick evaporites in the basin center. Fluvial and deltaic clastics dominate the Mesozoic and Tertiary with source rocks found in the Triassic. Jurassic sandstones are the principal reservoirs with the Cretaceous having minor reservoirs.

Most traps are found in association with salt structures with wrench fault related traps at the Drake Point and Hecla discoveries. Hydrocarbons are mainly dry gas with minor oil. The CGPC and GSC assessments vary widely which illustrates the uncertainty about the undiscovered potential here. The CGPC estimates 11 TCF GIP and the GSC between 26-33 TCF GIP. The NPC has chosen the CGPC estimate of 11 TCF GIP because of the relative exploration maturity and seal risk for large hydrocarbon columns. It is unlikely that any gas will be developed here before 2025.

The Arctic Coastal Plain contains sediments up to 12,000 meters thick and may have potential, but its remote location and shifting arctic ice pack make this region largely inaccessible to hydrocarbon exploration.

iii. Mackenzie Corridor

The Mackenzie Corridor is a collection of similar but separate basins that include the Mackenzie Plain, Peel Plain and Plateau and the Eagle Plain to the west of the Richardson Mountains. These basins are the northern extension of the WCSB, but the sediments were deeply eroded in pre-Cretaceous time. Most of the producing horizons of the WCSB were eroded: the Upper Paleozoic, Triassic, and Jurassic. Early Paleozoic sediments remain and like the Paleozoic section of the WCSB, they were deposited on the western margin of the North America continent in a shallow marine, shelfal environment. Sediments thicken to about 3,000 meters in the western part of the area. Some hydrocarbons have been found in a basal Cambrian sand lying below Cambrian salt with Cambrian shales as the source rock. To the west the Ordovician and Devonian limestones section grades and thickens into black, organic-rich marine shales. Middle Devonian reefs exist in the Mackenzie and Eagle Plain Basins and are productive in the Norman Wells oil field, but the field is so far unique. Many wells have been drilled to find other productive reefs and have been dry holes. The Cretaceous and Tertiary clastic wedge is present here, but is depositionally thinner than in the WCSB and is also partly removed by erosion. Seismic imaging is impaired by surface statics problems which is caused by limestones, glacial tills, and muskeg exposed at the surface. The CGPC assesses 6.5 TCF GIP undiscovered gas (4.6 TCF technically recoverable).

O. Eastern Canada Super-Region

1. Super-Region Summary

The 2001 CGPC assessment formed the basis for the NPC assessment of Eastern Canada (Figure S2-64). Eastern Canada has been divided into three regions: St. Lawrence (Ontario), Hudson Bay, and onshore Nova Scotia (Figure S2-65).

Total remaining technical resource is 6.2 TCF and cumulative production has been 1.1 TCF.

There have been about 190 pools discovered in Southern Ontario with minor oil and gas production

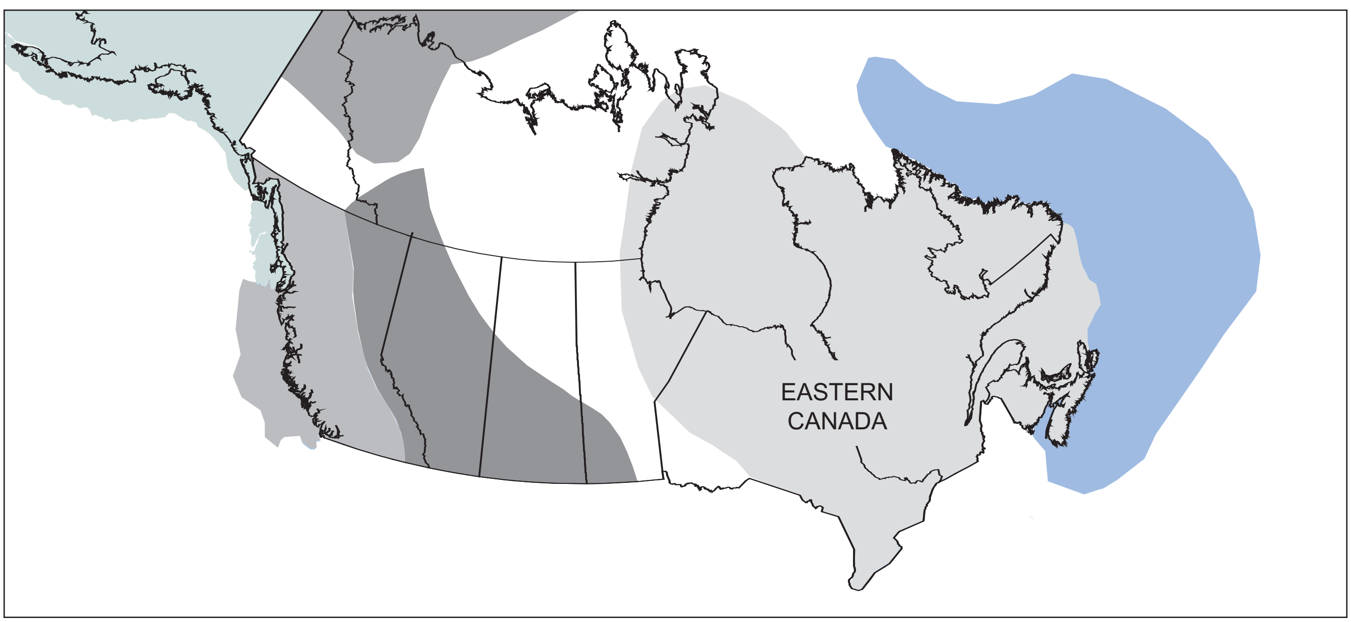


Figure S2-64. Location of the Eastern Canada Super-Region

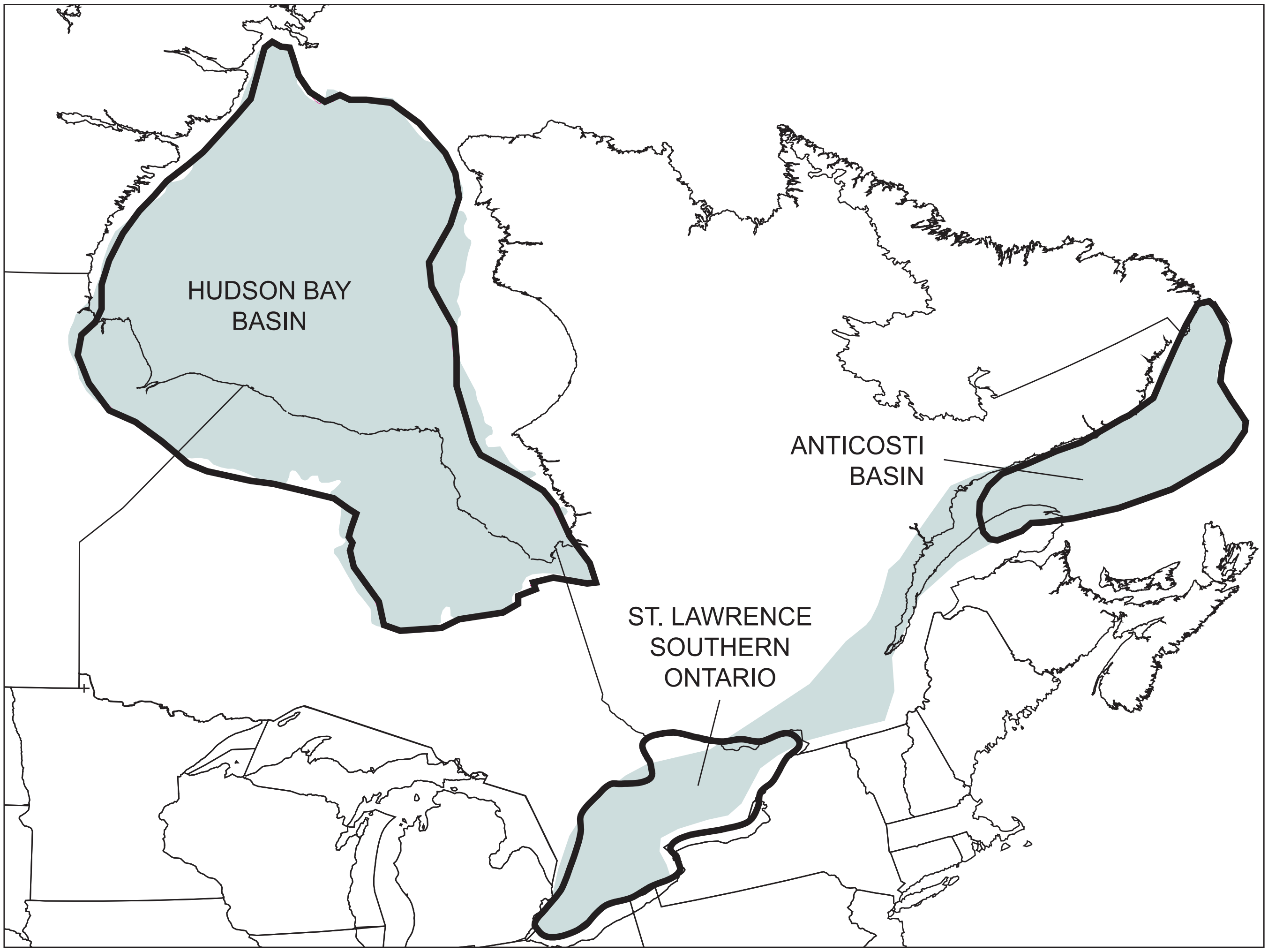


Figure S2-65. Eastern Canada Regions

from Silurian reefs. There have been no discoveries to date from Hudson Bay.

The NPC increased the CGPC assessment of undiscovered gas to 5.6 TCF recoverable. This increase is due to the inclusion of coal bed methane potential for onshore Nova Scotia and Prince Edward Island which was not assessed by the CGPC (increase of 3.9 TCF).

In the Reactive Path outlook, production increases from its current level of about 50 BCF/year to nearly 300 BCF/year in 2025 (Figure S2-66). The current zero level of drilling activity will increase to nearly 1,200 wells/year by 2025.

2. Eastern Canada Assessment Description

a. Remaining Gas Reserves

There have been about 190 pools discovered in the Eastern Canada. There is oil and gas production from Southern Ontario. The CGPC reports remaining proved reserves of 0.4 TCF in Eastern Canada, which is all in the Ontario area.

b. Growth of Existing Fields

In Eastern Canada the only production is from the old and very small pools in Ontario which have produced 1.1 TCF to date. The assessment for Ontario was done at the pool level, rather than the field level as in the United States. There is 0.2 TCF of growth assigned to Eastern Canada.

c. Undiscovered Fields Background Studies

The 2001 CGPC assessment formed the basis for the NPC supply model of the Eastern Canada. The CGPC study was selected by the NPC because it was considered to be the most detailed and recent study that covers all of Canada. The study is available for

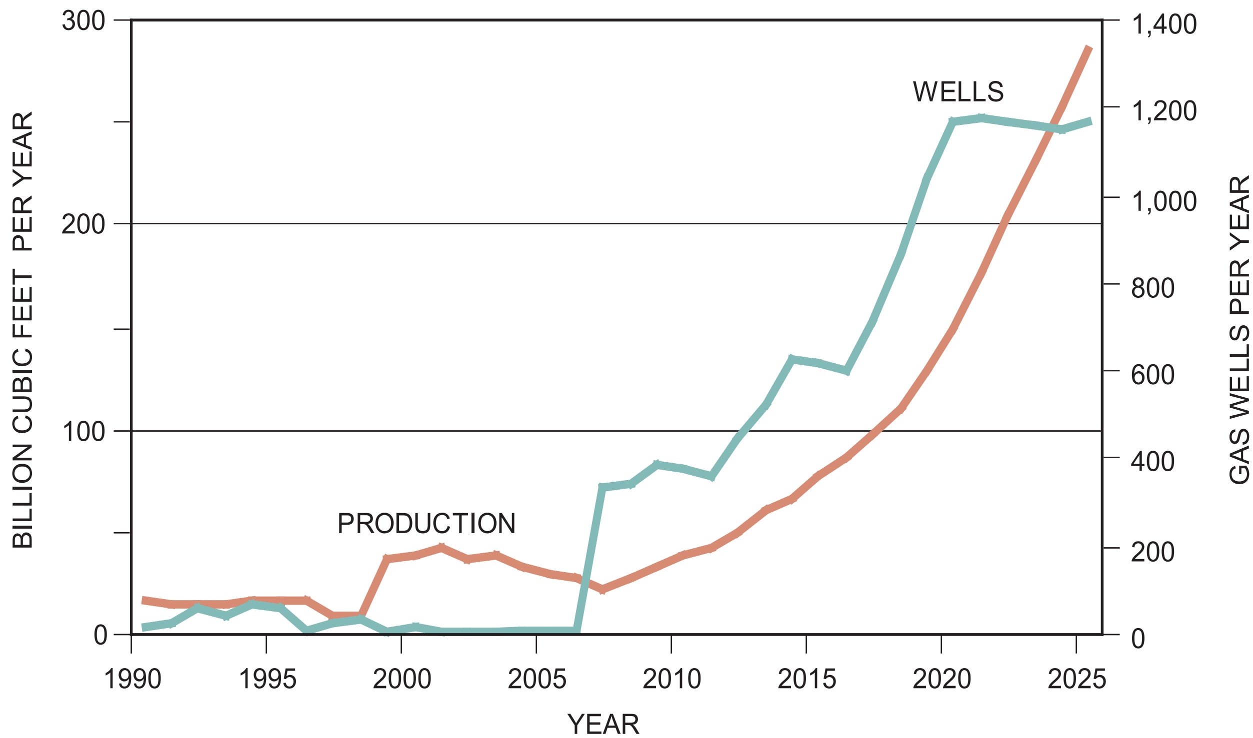


Figure S2-66. Eastern Canada Production and Drilling Forecast

purchase and can be found at the CGPC website (http://canadiangaspotential.com/report2.html).

An excellent overview of Canada hydrocarbon production and future potential is "Petroleum Resources of Canada in the Twenty-first Century" by K. Skipper in AAPG Memoir 74, Petroleum Provinces of the Twenty-first Century, 2001 (http://datacorp.petris.com/specpubs/memoir74/m74ch08/images/m74ch08.pdf).

d. Undiscovered Fields Results

The CGPC identified 19 plays in the Eastern Canada 12 of which were assessed and 7 plays were described but not assessed. The NPC made a 3.9 TCF recoverable gas increase over the CGPC assessment due to the addition of coal bed methane in onshore Nova Scotia and Prince Edward Island (Table S2-11). In addition, the NPC agreed with the CGPC assessment of 1.2 TCF GIP for

Eastern Canada Region	CGPC Undiscovered Gas GIP (Rec) (TCF)	NPC Undiscovered Gas* GIP (Rec) (TCF)
St. Lawrence (Ontario)	1.9 (1.4)	1.9 (1.4)
Nova Scotia Coal Bed Methane	Not assessed	22.0 (3.9)
Total	**1.9 (1.4)**	**23.9 (5.3)**

* NPC numbers exclude small field fraction for comparison purposes.

Table S2-11. Eastern Canada Undiscovered Gas – Comparison of NPC and CGPC

Hudson Bay but the CGPC did not publish an estimate for recoverable gas. Eastern Canada is divided into two regions which are described in more detail in the following sections: St. Lawrence (Ontario) and Hudson Bay.

i. St. Lawrence (Ontario)

Saint Lawrence River Valley. Southern Ontario lies between the Michigan and Appalachian Basins of the United States. Paleozoic rocks and plays found in these basins extend into Ontario. The stratigraphic section ranges from Cambrian to Devonian in age and contains sandstones, shelf, and reefal limestones and evaporites. Numerous small gas and oil fields have been found. Structural and stratigraphic traps include facies pinch-outs, sub-unconformity truncations, and upper Silurian pinnacle and patch reefs. The CGPC has assessed just under 2 TCF GIP (1.4 TCF recoverable) of undiscovered gas for southern Ontario and the NPC has accepted this without modification.

ii. Hudson Bay Basin

The Hudson Bay Basin contains a thin (up to 2 kilometer thick) Paleozoic section of Ordovician through Devonian platform limestones, small reefs, sandstones, and shales. These sediments are the remnants of a thicker sedimentary section that has been largely eroded. There are no discoveries to date, but the CGPC does assess a small volume in speculative plays based on the presence of organic-rich marine shale within the Ordovician and Devonian, bitumen in pore spaces and structuring associated with basement faulting. The chance of success is low due to the risk of thermal immaturity. Geochemical studies from data in a well in the deepest part of basin showed the sediments to be immature. Even if maturity was achieved elsewhere in the basin, hydrocarbon generation and migration timing is also a risk. The CGPC assessed an undiscovered potential of 1.2 TCF GIP but did not publish a technically recoverable number. This small volume was not included in the economic model due to high play risk.

iii. Eastern Canada Nonconventional Resources

Coal Bed Methane. The CGPC did not assess any nonconventional undiscovered gas resource for the Eastern Canada. The NPC workshop used an estimate by David Hughes of GSC (in press) with a maximum of 22 TCF coal bed GIP for Nova Scotia and Prince Edward Island. In addition, there are active coal bed methane leases and pilot projects in northwestern Nova Scotia by Amvest Nova Scotia. The NPC consensus is that the Eastern Canada coal bed methane is 22 TCF GIP (3.9 TCF recoverable) and with nearby infrastructure available, production is possible by 2006. The estimate for average recoverable gas per well is 0.25 BCF.

P. Canada Atlantic Super-Region

1. Super-Region Summary

The 2001 CGPC assessment formed the basis for the NPC's assessment the Canada Atlantic (Figure S2-67). Canada Atlantic has been divided into four regions: offshore Nova Scotia, offshore Newfoundland, offshore Labrador, and Maritimes Basins (Figure S2-68).

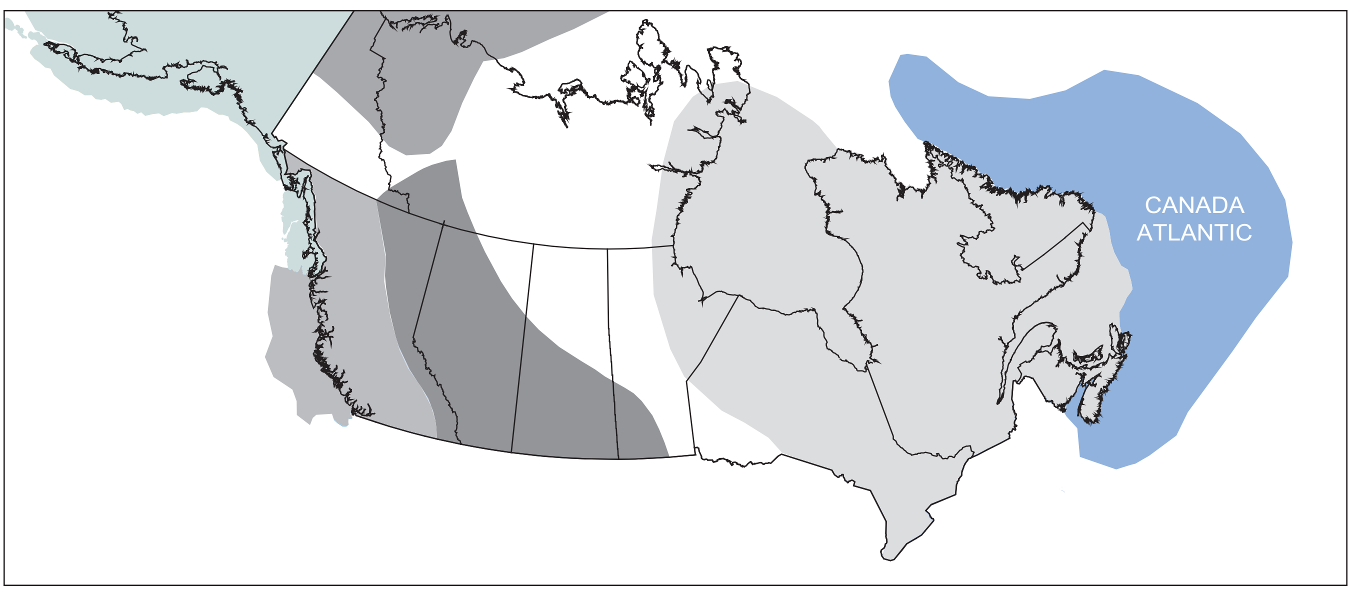


Figure S2-67. Location of the Canada Atlantic Super-Region

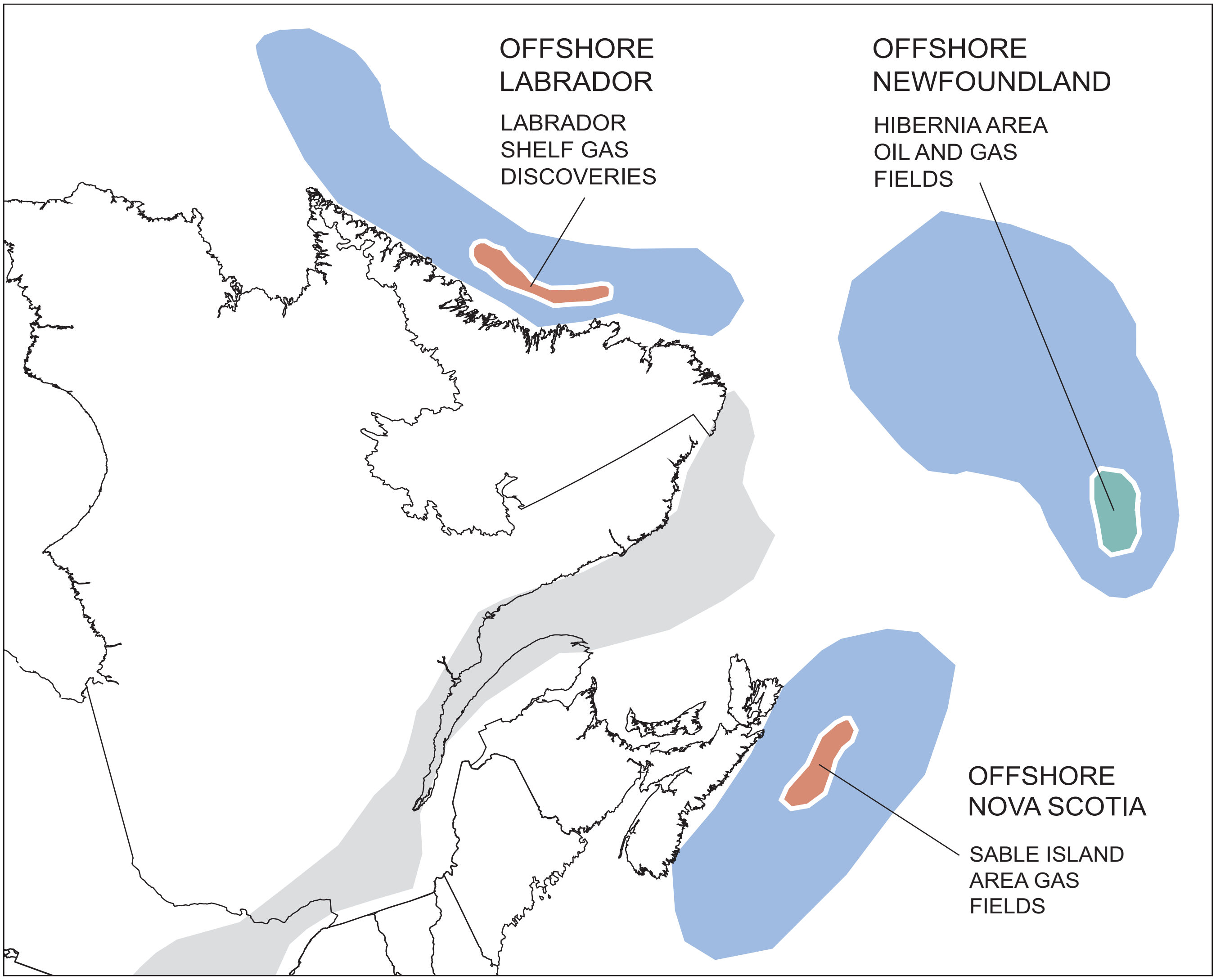


Figure S2-68. Canada Atlantic Regions and Areas of Discoveries

There have been about 44 fields discovered and there is gas production from offshore Nova Scotia and oil production from offshore Newfoundland. Gas discoveries offshore Labrador are not yet developed. The 21 discoveries offshore Nova Scotia are almost all gas fields, the 18 discoveries offshore Newfoundland are mostly oil or oil and gas fields, and the 5 discoveries offshore Labrador are all gas fields.

The total remaining technical resource is 85.4 TCF and cumulative production has been 0.3 TCF.

The NPC increased the CGPC assessment of undiscovered gas to 97 TCF GIP, which is an increase of 57.8 TCF GIP (Table S2-12). NPC total recoverable, including small fields, is 68 TCF. Discovered fields not yet developed total 26.6 TCF GIP (15.0 TCF recoverable). Offshore Labrador is much more remote than the other two areas and any development there will be at a much later date.

In the Reactive Path outlook, the current production of about 200 BCF/year will increase in 2012 to about 450 BCF/year and increase further to about 800 BCF/year in 2025 (Figure S2-69). The current low level of drilling activity will jump to between 6 and 30 wells/year post-2010.

2. Canada Atlantic Assessment Description

a. Remaining Gas Reserves

There have been about 44 fields discovered in Canada Atlantic. There is gas production from offshore Nova Scotia (Venture Field complex) and oil

Canada Atlantic Regions	CGPC Undiscovered Gas GIP (Rec) (TCF)	NPC Undiscovered Gas* GIP (Rec) (TCF)
Maritimes Basins	Not assessed	2.2 (1.4)
Offshore Nova Scotia	17.6 (10.6)	41.2 (26.7)
Offshore Newfoundland	15.5 (6.6)	13.0 (8.5)
Offshore Labrador	6.1 (4.4)	40.6 (26.4)
Total	**39.2 (21.4)**	**97.0 (63.0)**

*NPC numbers exclude small field fraction for comparison purposes.

Table S2-12. Canada Atlantic Undiscovered Gas – Comparison of NPC and CGPC

production offshore Newfoundland (Hibernia and Terra Nova Fields) in which the gas is being re-injected. There are 2.2 TCF of proved reserves in offshore Nova Scotia. The CGPC reports an additional of 26.6 TCF GIP (15.0 TCF recoverable) of discovered gas which is not yet developed in Canada Atlantic.

b. Growth of Existing Fields

In Canada Atlantic there are only a few fields on production, most are still awaiting development. There has been a total of 0.3 TCF of gas production to date from offshore Nova Scotia. There is estimated to be 0.3 TCF of future growth from these fields. The 15 TCF of

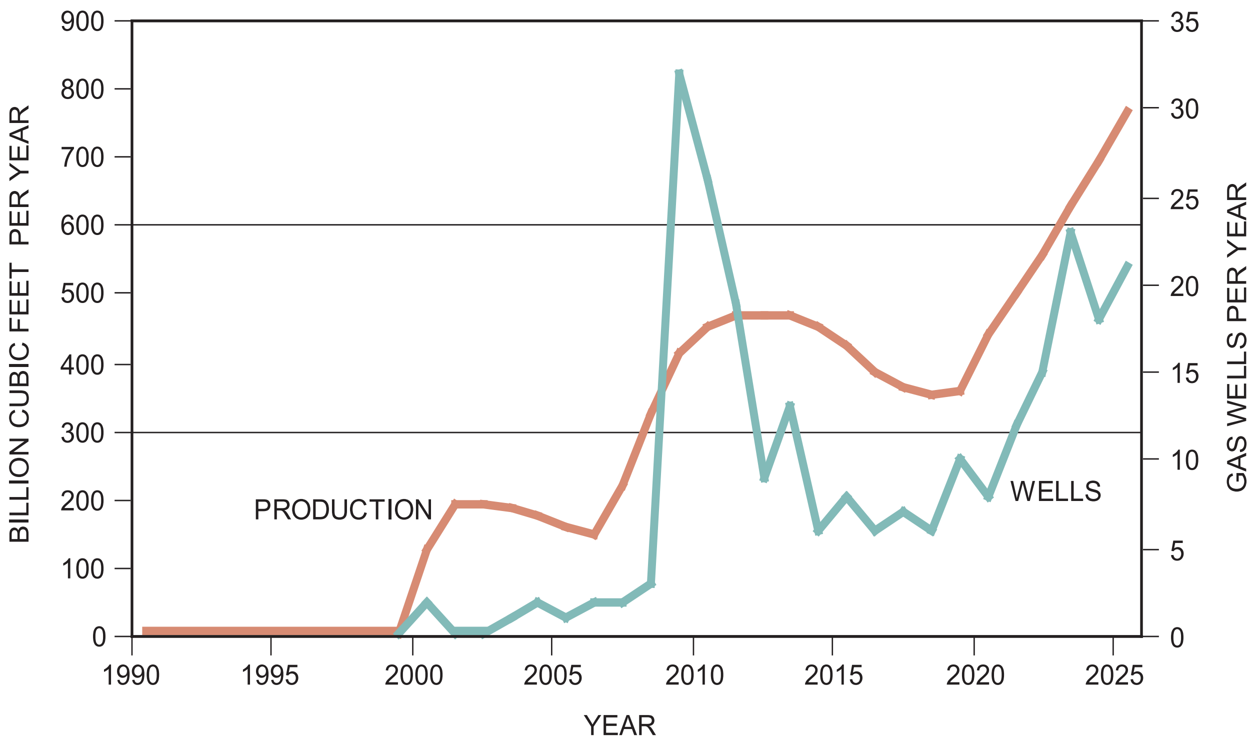


Figure S2-69. Canada Atlantic Production and Drilling Forecast recoverable discovered gas which can not yet be classified as proved reserves are included in growth to known for a total growth of 15.3 TCF for Canada Atlantic.

c. Undiscovered Fields Background Studies

The 2001 CGPC assessment formed the basis for the NPC supply model of the Canada Atlantic. The CGPC study was selected by the NPC because it was considered to be the most detailed and recent study that covers all of Canada. The study is available for purchase and can be found at the CGPC website (http://canadiangaspotential.com/report2.html).

The Nova Scotia Offshore Petroleum Board has information related to offshore Nova Scotia on their website (http://www.cnsopb.ns.ca/Generalinfo/general.html). The Canada-Newfoundland Offshore Petroleum Board has a number of publications related to existing production and future potential of offshore Newfoundland and Labrador (http://www.canadalegal.com/gosite.asp?s=1091). An excellent overview of Canada hydrocarbon production and future potential is "Petroleum Resources of Canada in the Twenty-first Century" by K. Skipper in AAPG Memoir 74, Petroleum Provinces of the Twenty-first Century, 2001 (http://datacorp.petris.com/specpubs/memoir74/m74ch08/images/m74ch08.pdf).

d. Undiscovered Fields Results

The CGPC identified 23 plays in Canada Atlantic, 7 of which were assessed and 16 plays were described but not assessed. The NPC made a 57.8 TCF increase over the CGPC assessment due to the addition of the Scotian Slope which was not assessed by the CGPC and a significant increase in Offshore Labrador potential. Canada Atlantic is divided into four major regions which are described in more detail in the following sections: offshore Nova Scotia, offshore Newfoundland, offshore Labrador, and Maratimes Basins.

A number of sedimentary basins lie in Canada Atlantic. These basins trend northeasterly from Georges Bank to the Grand Banks, then turn to the northwest to Baffin Bay. Together these basins cover a distance of about 5,500 kilometers. There are five principal depocenters: The Scotian Basin stretching from Georges Bank to the Grand Banks, the Newfoundland Basin that contains the Hibernia oil and gas field, the Hopedale and Saglek Basins along the Labrador margin, and the Baffin Bay Basin. These Basins are separated from one another by basement arches. The basins become progressively younger to the north, having formed during the opening of the Atlantic Ocean. Each of these basins lie on the passive margin of the North America craton and are filled with successive sequences of generally eastward prograding sediments. While some Paleozoic rocks are found along the basin margins, almost all of the undiscovered potential is thought to be contained within the thick Mesozoic and Cenozoic sedimentary sequences. The majority of discoveries are in Upper Jurassic and Lower Cretaceous sandstone reservoirs. Several large oil and gas discoveries have been found in the Jeanne d'Arc basin (e.g., Hibernia and Whiterose fields). Most Canada Atlantic gas discoveries are remote, not fully delineated and are presently non-commercial. Size estimates therefore are subject to some uncertainty. Gas exploration is immature in parts of these basins, as initial exploration efforts were focussed on oil and there is still significant undiscovered gas potential.

i. Offshore Nova Scotia

The Scotian Basin depocenter is a seaward thickening wedge of Mesozoic and Cenozoic sediments that attains a maximum thickness of 12 kilometers near Sable Island. The oldest prospective sediments are Triassic. Non-marine clastics and evaporites accumulated in Triassic and early Jurassic rift grabens. Thick Jurassic and Lower Cretaceous deltaic sequences prograded eastwards with some shelfal carbonates deposited in the late Jurassic. The Upper Cretaceous and Paleogene are marine transgressive sequences and these are overlain by Neogene prograding clastics.

Thick Upper Jurassic-Lower Cretaceous fluvial and deltaic sandstones are the primary reservoir targets on the shelf with roll-over anticlines a common trap type. Down-dip, age-equivalent shelf margin delta, slope channels and deep-water fans are the reservoir targets in present day deep water. The Abenaki shelf carbonates develop good porosity locally and are a proven exploration target (the Deep Panuke gas discovery). Roll-over anticline traps occur along the shelf edge and are often gas-bearing (e.g. Venture field). Structural and structural-stratigraphic traps are likely to be found in deep water associated with complex salt tectonics. Source rocks on the shelf are known to be gas prone and mature in the Upper Jurassic and Lower Cretaceous. It is not known if the shelf sources extend into deeper water or if other source intervals observed around the circum-Atlantic might be present and thermally mature.

Sable Sub-basin (Scotian Shelf). The CGPC assessed undiscovered gas potential to be 8 TCF GIP. The size of new field discoveries is declining and at least 4 disappointing wells have been drilled since the CGPC assessment. The principal risks are seal and reservoir quality. Remaining prospects are very low relief structures with small columns or fault traps with high seal risk due to abundance of sand in the section. There are a few larger deep prospects but these have high reservoir quality risk. Representatives of the CGPC commented that if the CGPC were to re-assess this play they would decrease undiscovered gas volumes. Representatives from Shell said they would cut the CGPC assessment in half (to 4 TCF GIP). NPC consensus is 3 TCF GIP of undiscovered potential. This volume is based on 15 leads with an average size of 100 BCF recoverable and maximum size of 500 BCF, probability for geologic success 60% and probability for commercial success 20-30%.

Deep Panuke Play (Jurassic Reef Edge Trend). The CGPC did not assess this play, but assigned it 1 TCF GIP of discovered resource based on an Encana press release about their deep Panuke discovery well. To date, there have been at least 6 other play tests which have failed. The Jurassic carbonate shelf edge is a narrow play fairway with dolomitized and karsted bank edge targets with increasing risk away from source rocks associated with the Mississauga delta. The NPC consensus is 3 TCF GIP of undiscovered gas based on an estimated 10 remaining prospects each with > 200 BCF GIP size potential with the largest possibly up to 1 TCF GIP. The probability for geologic success is assumed to be 30% and the probability for commercial success is 20%. Targets lie in 60-500 meters water depth and at 3,500-4,000 meter drill depths. The deep Panuke gas is slightly sour, requiring special pipe and gas processing.

Abenaki Sub-basin (Scotian Shelf). The CGPC assesses 7.1 TCF GIP with a 50% chance the play exists. This is a mixed carbonate and siliclastic depositional system that tends to have poor porosity. There is a general lack of structuring and risk for adequate source. To date, 23 wells have been drilled with 1 non-commercial oil and 1 non-commercial gas show. There are thought to be few remaining prospects. NPC consensus assessment is only 2 TCF GIP of undiscovered potential. The largest remaining pool is thought to be no larger than 300 BCF GIP. Water depths are about 100-150 meters and drill depths 3,000-4,500 meters. This is expected to be a high pressure-high temperature (HPHT) play.

Scotian Slope. The CGPC did not assess the slope plays. The Canada Nova Scotia Offshore Petroleum Board (CNSOPB) in 2002 assessed the undiscovered potential to be 15 TCF risked recoverable non-associated gas. This assessment included 12 plays with 10 TCF in "mini-basin" flank traps and 5 TCF on the upper slope. The assessment excluded associated gas and no field size distribution information was provided. Two wells were recently drilled in the deepwater south of Sable Island, but very little data has been released to the public domain. Representatives from Shell shared with the NPC workshop participants that they estimate between 50 to 70 leads > 500 BCF and a maximum expected field size of about 3 TCF. They estimate the probability for geologic success to be about 40%. Targets are 3,000 to 4,000 meters below the mudline in an average water depth of 1,800 meters. The play is thought to be HPHT. Source presence, distribution, and richness are the principal risks. NPC consensus is 20 TCF of undiscovered recoverable gas. This includes 15 TCF from the CNSOPB assessment and an additional 5 TCF for the Newfoundland extension of the slope not assessed by the CNSOPB.

Georges Bank. The basin is a structural sag, 18,000 km2 in areal extent, that trends southwest-northeast and is thickest in the southwest. The Georges Bank basin partially underlies the southwestern end of the Scotian Basin and is separated from it by the Yarmouth Arch. The basin formed in the Early Jurassic and has up to 4 kilometers of Middle Jurassic section comprising predominantly carbonate rocks. These carbonates are interbedded with clastics to the west and overlain by Upper Jurassic through Tertiary shallow water clastics and carbonates. There are no proven plays but Upper Jurassic and Cretaceous sandstones are potential reservoirs and structural traps may be associated with the Yarmouth Arch or basement faulting. Scotian shelf and U.S. wells suggest potential source intervals will be in the Upper Jurassic and Cretaceous section, but these intervals are thought to be mostly immature. The potentially mature Middle Jurassic contains only low levels of gas-prone source rocks. ChevronTexaco holds substantial acreage in the basin, but no wells have yet been drilled. The area is under moratorium until at least 2012. It is doubtful there will be any exploration effort before 2025. The area could have 1 to 2 TCF GIP undiscovered potential, but the NPC consensus was to leave the basin unassessed.

ii. Offshore Newfoundland

Grand Banks and East Newfoundland Shelf. The Grand Banks area is characterized by a number of rift basins, each containing a syn-rift Mesozoic sedimentary succession that has been eroded and capped by a regional mid-Cretaceous unconformity. These basins formed during the separation of North America and Europe. Recognized basins include the Whale, Horseshoe, Carson, South Whale, and Flemish Basins. The Mesozoic sediments are deformed and locally have been deeply eroded. Upper Cretaceous and Tertiary deep water shales up to two kilometers thick overlie the mid-Cretaceous unconformity and may have source potential but are not thermally mature. Reservoir targets lie within the pre mid-Cretaceous unconformity section and traps can be formed by a variety of basement and salt-involved structures. Exploration has proven largely unsuccessful in most of these basins, owing largely to erosion of Late Jurassic source beds. However, in the Flemish Pass area Kimmeridgian source rocks are preserved.

The East Newfoundland Shelf/Jeanne d'Arc area began with the break-up of Europe and North America. Like the Grand Banks basins, the shelf is underlain by a thick succession of Mesozoic sediments. The Triassic has graben fill non-marine clastics and evaporites overlain by Jurassic marine sediments that contain a rich organic source interval in the Kimmeridgian. The Lower Cretaceous is a clastics sequence which overall fines upwards overlain by Upper Cretaceous and Tertiary deep-water mudstones and shales, which are up to 5500 meters thick. The giant Hibernia Field is a large roll-over anticline associated with a hinge fault zone with oil and gas in Upper Jurassic and Lower Cretaceous deltaic and shallow marine sands. Most of the Jeanne d'Arc basin gas discovered to date is associated with oil, and no gas is currently commercially produced. Traps are provided by deep seated faults and salt structures with stratigraphic traps possible associated with the mid-Cretaceous unconformity and along the basin edge.

The CGPC assessment of the Jeanne d'Arc and Flemish Pass is 10.4 TCF GIP undiscovered potential. There is an additional 9.3 TCF GIP in 15 discovered fields (6.7 TCF recoverable and about 4.3 TCF of this is associated gas).

NPC workshop participants emphasized that exploration has been for oil, not gas. In the assessment area there are several deep, large salt-related structures not yet drilled because they are gas prospects. The Flemish Pass and Jeanne d'Arc basins are separated by an arch, have different structural styles, different burial histories, different levels of exploration maturity and risk, and many participants felt they should be assessed separately. Approximately 80% of the undiscovered gas resource is in the Jeanne d'Arc and 20% in the Flemish Pass. The Flemish Pass has not yet been proven productive.

The Jeanne d'Arc basin contains structures such as tilted fault blocks, roll-over anticlines and salt-related features. The southern Jeanne d'Arc is in a mature exploration stage with no large remaining prospects, but to the northwest the deep basin area is very lightly drilled. This northwest area is considered to be gas prone. It is estimated that 10-20 gas prospects might be found with an average size of 300-500 BCF and the largest up to 3 TCF GIP. The geologic chance of success is estimated at 30% and the economic chance of success at 10%. There is increasing reservoir risk northwards away from the Avalon Arch provenance and with deeper burial. There is diverse opinion about the undiscovered potential of this area with estimates ranging from 5-25 TCF GIP. The CNOPB assessment is 18 TCF recoverable. The NPC agreed with the CGPC assessment of 8 TCF GIP of undiscovered gas. Water depths are generally less than 200 meters and drill depths range between 4,000 and 5,000 meters. Initial production is likely between 2015-2020 because gas already discovered at Hibernia, White Rose, and Terra Nova are nearly sufficient to be commercially developed. There are currently no CNOPB regulations or fiscal regime for gas development.

There is less Tertiary thickness in the Flemish Pass than Jeanne d'Arc basin resulting in lower source maturity and thus the Flemish Pass is considered more oil prone. The Flemish Pass is at a fairly mature stage of exploration with 3-D seismic across the entire area. It is estimated that there are only 10 prospects remaining. Results from 2 recent PetroCanada-operated wells in the area have been disappointing. NPC consensus is 2 TCF GIP undiscovered potential. Drill depths will be from 3,000 to 4,500 meters in water depths of 100 to 1500 meters. There are no current CNOPB regulations or fiscal regime for gas development.

Orphan Basin. The basin is closely related to the adjacent East Newfoundland Shelf. Upper Paleozoic sediments are deformed and block faulted and overlain by Mesozoic rift basin sediments. Rift sediments are subsequently folded, faulted, and locally truncated at the mid-Cretaceous unconformity. Upper Cretaceous and Tertiary deep-water shales and mudstones overlie the unconformity. One well (the Blue well) was drilled on the crest of a rift related, basement involved horst which found porous, water bearing Cretaceous sandstones and low porosity Paleozoic reservoirs. An expanding wedge of undrilled, probable Jurassic and Cretaceous age section is seen on seismic data to be developed off-structure. These beds could potentially contain porous reservoirs. For this basin to hold significant volumes of hydrocarbons the Kimmeridgian sources developed in the Jeanne d'Arc would need to extend northward. Thermal modeling, along with geochemical data from the Blue well, suggest that, if present, the Kimmeridgian could be locally mature. Several large structures and potentially trapping stratigraphic geometries are seen on seismic data. Numerous structural prospects associated with tilted basement horsts have been mapped.

There are no proven plays and workshop discussions concluded that the principal risks are adequacy of reservoir and source. It is uncertain if the basin developed early enough to contain the Kimmeridgian Egret source beds, found in the Jeanne d'Arc basin. If present, the play may likely be oil prone. There is less Tertiary sediment here than in the Jeanne d'Arc Basin, but the Cretaceous is thick enough to mature a Jurassic source in the western part of the basin but the eastern side may be immature. The 6-7 western basin margin wells are drilled high on structure and found only thin Oligocene fans. No Mesozoic reservoirs were encountered.

The NPC agreed with the CGPC undiscovered gas potential estimate of 5 TCF GIP.

If Orphan Basin exploration is successful, these discoveries might be developed before 2025. Assuming Jeanne d'Arc Basin gas is onstream in the next 10 to 15 years, infrastructure would be relatively close, facilitating development of Orphan gas. Approximately 50% of the basin has water depths > 2,000m with average drill depth of ~ 4,000 meters. Discoveries may be developed with an FPSO. The area is environmentally sensitive and iceberg prone. Regulations require the capability of a relief well to be drilled in the event of a blow-out so two rigs will be needed in the area during a drilling campaign. There are no exclusion zones. Environmental studies will be required and increase costs.

iii. Offshore Labrador

The Hopedale and Saglek Basins originated with rifting of North America and Europe but rifting offshore Labrador is younger than off Newfoundland. Rift sediments overlie a block-faulted Paleozoic terrain with clastics and carbonates that might locally provide reservoirs. Early rift sediments in the Hopedale Basin accumulated in an inner shelf graben characterized by Lower Cretaceous volcanics and arkosic sandstones overlain by Upper Cretaceous to Lower Tertiary shales which are capped by a seaward thickening wedge of younger Tertiary siltstones, sandstones, and mudstones. The Saglek Basin contains up to 10 kilometers of Tertiary section.

Cretaceous and Tertiary reservoirs draped over basement involved structures or folded within detached listric faults are a common trap type. Widespread hydrocarbon shows suggest regional development of source rock. These are likely Lower Cretaceous Bjarni Formation gas-prone lignites and coals and/or Paleocene oil-prone shales. It is not known if these likely source intervals extend to the slope. In the Hopedale Basin there are five gas and condensate discoveries totaling 5 TCF GIP and at least three discoveries (Bjarni, Gudrid, Snorri) with heavy oil and low GOR from an immature source all related to basement highs. The Hekja well discovered 40 m of gas pay on the north flank of the Saglek Basin in folded Paleocene sandstones which is the northernmost hydrocarbon discovery along the Atlantic coast of North America. There has been no drilling offshore Labrador since the 1980s.

There is potential for large undiscovered fields along the Labrador Shelf. Seismic data reveal more than 25 undrilled structures with 1 to 2 TCF GIP potential. Direct hydrocarbon indicators (DHIs) are observed on seismic. The CGPC assesses 6 TCF GIP of undiscovered potential. The CNOPB assesses 22 TCF of undiscovered recoverable potential. The GSC assesses 26 TCF recoverable undiscovered potential. There has been no exploration in deep water beyond the shelf-slope break and so resource potential could be even higher.

Bob Meneley (CGPC) expressed concern about assessments larger than the CGPC 6 TCF GIP undiscovered estimate. He pointed out that the largest mapped structure is drilled, that the east-side listric fault trend play is still conceptual with 2 dry tests to date and that stratigraphic traps for Bjarni sands onlapping basement highs have been tested unsuccessfully. He believes that for the GSC assessment of 26 TCF undiscovered recoverable to be possible it will have to be in conceptual (unproven) plays.

The NPC workshop participants recognized that the 5 TCF of gas discovered was in wells exploring for oil. Government regulations require that all hydrocarbons be validated by testing so DHIs have been avoided because they were presumed to be gas. NPC consensus was to accept the GSC undiscovered gas assessment of 40 TCF GIP (26 TCF recoverable).

There are a number of issues that make development of these discoveries unlikely before 2025. The Labrador Shelf is in "iceberg alley." There is only a 3 to 4 month drilling season, and wells must be drilled and tested over 2 to 3 seasons. Ice scouring makes transportation difficult; pipelines would need to be buried. The location is very remote and a long distance from any infrastructure. Wells cost C$60-80MM and possibly up to C$100MM to drill.

iv. Maritimes Basins

Several small Paleozoic basins with more than 5 kilometers of sedimentary section lie west and northwest of Nova Scotia, which include the Fundy and Magdalen Basins. Non-marine Devonian to Lower Jurassic basin fill mainly consists of arkosic sandstones, evaporites, shales, and a few thin limestones. Two small discoveries have been made. Stoney Creek in New Brunswick, discovered in 1909 and reportedly containing oil and gas, produced 20 to 30 BCF of gas and was likely not properly developed. The East Point well tested a small volume of gas in 1974 in the Gulf of St. Lawrence from late Carboniferous sands in a salt-cored structure. The Anticosti Basin is located west of Newfoundland and northeast of New Brunswick. An older Paleozoic more marine section is present here with Cambrian to Devonian mixed carbonates and clastics. Ordovician shales and basinal Silurian carbonates may be the source for oil seeps in western Newfoundland and the Gaspe peninsula of Quebec and a reported oil discovery.

There is uncertainty about the potential of these basins. There appears to be the possibility of a working hydrocarbon system in each of these basins with marine source rocks in the Anticosti Basin. There are thick Carboniferous coal-bearing sections in the predominantly non-marine basins south of the Anticosti basin. Coals could be the source of the gas and oil found in the Stoney Creek field and the East Point well. Salt cored anticlines provide traps and porous sandstones and shelfal limestones are potential reservoirs. Only 2 or 3 large structures are thought to be left undrilled, though a subsalt play might be possible. The CGPC recognizes several plays but did not assess any undiscovered gas potential for these basins. NPC consensus is 1.4 TCF of undiscovered gas associated with the salt cored anticlines in the Carboniferous-Permian basin.

The attraction of these basins is close proximity to the Sable Island pipeline and nearby markets. The basins lie partly onshore and partly offshore. This may create some access difficulties until the regulatory environment is fully defined between the provinces and the federal government. Winter pack ice offshore will be another obstacle to development.

Q. Mexico Super-Region

1. Super-Region Summary

The IHS Energy "Focus on Mexico" and USGS 2000 World Petroleum Assessment is the basis for the NPC Mexico assessment (Figure S2-70). The NPC estimates 58 TCF of undiscovered gas in Mexico (Table S2-13). The Burgos Basin located adjacent to southern Texas (Figure S2-71) is the most important non-associated gas basin in Mexico with undiscovered gas of 20 TCF. The other significant area is Sureste onshore and offshore with undiscovered gas of 22 TCF which is mostly associated gas.

Total remaining technical resource is 121.0 TCF and cumulative production has been 48.5 TCF.

Well density in Mexico is significantly lower than adjacent areas of the U.S. For the onshore Burgos Basin there is significant potential for growth of existing gas fields by infill drilling and reduced spacing. The offshore Gulf of Mexico is very lightly drilled compared to the U.S. Gulf of Mexico, especially in the deepwater, and appears to have good potential for future discoveries.

Mexico was divided into five regions with significant undiscovered gas potential: Sabinas, Burgos, Tampico-Misantla, Veracruz, and Sureste (Figure S2-70). All of these regions have onshore, shelf, and slope components except for Sabinas, which is exclusively onshore. The regions are further subdivided by water depth and drilling depth for economic analysis.

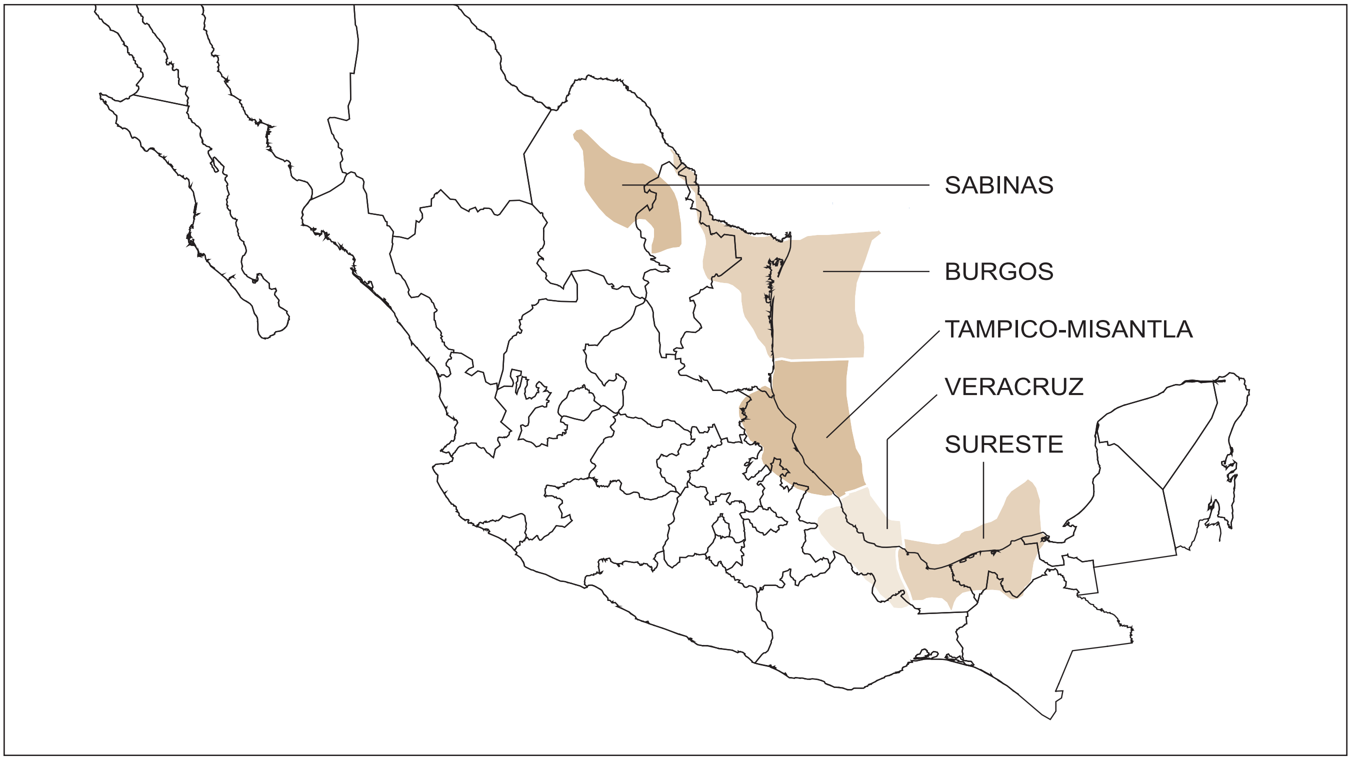


Figure S2-70. Mexico Regions

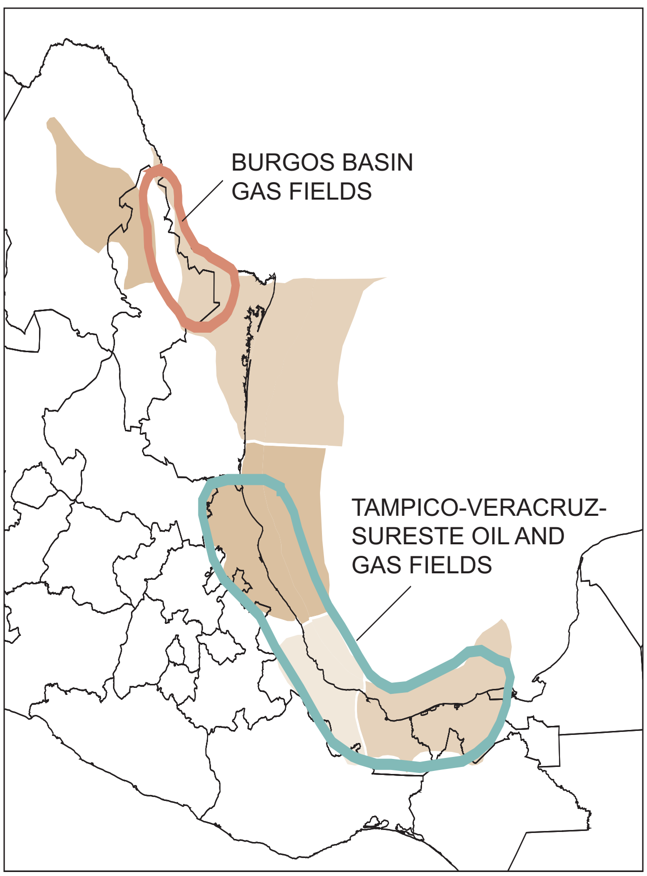


Figure S2-71. Mexico Areas of Production

Mexico Region	IHS 2000 (TCF)	NPC 2003 (TCF)
Sabinas	2	2
Burgos	25	20
Tampico-Misantla	6	6
Veracruz	2	8
Sureste	21	22
Total	**56**	**58**

Table S2-13. Mexico Undiscovered Gas in Fields >6 BCF

2. Mexico Assessment Description

a. Remaining Gas Reserves

PEMEX publishes an annual compilation of remaining oil and gas reserves by field and region for all Mexican fields. This was used to determine remaining gas reserves in Mexico. Remaining proved gas reserves as of January 2002 are 28.1 TCF. Total remaining reserves (proved+probable+possible) are 50.6 TCF (from "Prospectiva del Mercado de Gas Natural 2002-2011" by Secretaria de Energia (SENER), Mexico City, 2002).

b. Growth of Existing Fields

It is recognized that estimates of ultimately recoverable reserves change through time as new information about a field is learned and as new pools are discovered and developed. There are generally three categories of field reserves characterized by different levels of certainty. Proved reserves are the most certain, probable reserves are still likely to be present but the uncertainty is greater and possible reserves are the least certain. When a field is first discovered only a few wells are drilled and the total size and extent of the field is not absolutely known. As the field is developed reserves are generally transferred from the more uncertain to the more certain categories. Late in the life of a field most of the reserves are accounted for in the proved category but this is not the case early in the life of a field.

For Mexico the data was not publicly available to perform the well-based EUR cohort methodology. Mexico does publish estimated reserves for all fields by category (proved, probable, and possible) so it was decided to use the probable plus possible reserves as equivalent to future growth. Using that assumption future growth for Mexico is 22.5 TCF.

c. Undiscovered Fields Background Studies

The IHS Energy "Focus on Mexico" report in 2001 did a countrywide estimation of undiscovered gas of Mexico. This report was licensed by the NPC and was the primary basis for the analysis of undiscovered gas in Mexico. A description of the report can be found at the IHS Energy website: (http://www.ihsenergy.com/products/studies/latinamerica/index.jsp#newmexico).

The USGS 2000 World Petroleum Assessment was also used as a basis for the assessment of Mexico. The USGS assessment covered part of Mexico which included Sureste, Veracruz, and Tampico-Misantla (http://greenwood.cr.usgs.gov/energy/WorldEnergy/DDS-60/).

The NPC methodology was to assemble industry and government experts and hold a two-day workshop to validate and change, if necessary, the mean resource estimates for key large plays. This workshop was held in Houston, Texas.

d. Undiscovered Fields Results

The IHS assessment was done at basin or areal subdivision of basin level while the USGS assessment was done at the play level. The NPC divided Mexico into several regions similar to I.H.S. Energy divisions but only considered areas with over 1 TCF of undiscovered gas potential: Sabinas onshore, Burgos onshore and offshore, Tampico-Misantla onshore and offshore, Veracruz onshore and offshore, and Sureste onshore and offshore.

IHS estimated that there is 56 TCF of undiscovered gas resource in the NPC regions of interest. The NPC slightly increased this to a total of 58 TCF with significant changes in two regions. The Burgos onshore and offshore was reduced by 5 TCF and the Veracruz onshore and offshore was increased by 6 TCF.

The NPC experts differed with the IHS Burgos offshore shelf assessment of 7 TCF. This assessment was based on a PEMEX publication which listed 30 prospects of size 100-500 BCF which resulted in 7 TCF of undiscovered gas. NPC experts felt that these prospects should be given a chance of success of 30% which would result in 2 TCF of undiscovered gas. NPC experts also felt that the poor exploration success in the adjacent Texas shelf should be considered when assessing the Burgos offshore. There is only one well offshore Burgos, drilled to 13,153 feet in 1973, which is a dry hole. The Burgos slope (deepwater) was not assessed by I.H.S. so the NPC did an assessment of this area. The play is the Perdido foldbelt which has been drilled on the U.S. side. There were assumed to be 40 prospects with a change of success of 20% and an average size of 75 MMBO. This is assumed to be an oil play which would result in undiscovered potential of 600 MMBO and 0.6 TCF of associated gas.

The Veracruz onshore and offshore was increased by NPC expert consensus by 6 TCF. Most of the increased potential is considered to be in the offshore portion. The NPC preferred the USGS assessment for this area and thus increased the assessment relative to I.H.S. The Lankahuasa Miocene sands gas discovery in the Veracruz offshore has proved+probable reserves in the 700 BCF range and there are a number of undrilled smaller prospects in the area based on a presentation by Alfredo Guzman Baldizan (http://www.csm.pemex.com/english/04docs/gassector.html).

3. Comparison with NPC 1992 Mexico Assessment

The NPC 1992 Study included a resource estimate for gas in Mexico. Mexico was not assessed in the NPC 1999 Study. The NPC 2003 Study assessed Mexico and a comparison was made to NPC 1992. Table S2-14

Assessment Category	NPC 2003 (TCF)	NPC 1992 (TCF)	2003/1992 (%)
Proved	28	72	39%
Growth	22	87	25%
Conventional Undiscovered (Includes Small Fields)	70	93	75%
Mexico Total	**120**	**252**	**48%**

Table S2-14. Mexico Gas Resource Assessment Comparison

shows that the NPC 2003 estimate is approximately half of NPC 1992 due to lower estimates of proved reserves, growth, and undiscovered conventional new fields.

a. Proved

Proved gas reserves in both 2003 and 1992 came from PEMEX publications. One large field named Chicontepec had 27 TCF of undeveloped reserves in 1992 which have been subsequently removed from the proved category due to the field being uneconomic to develop in the near term. Once this field is removed then there is less difference between the 2003 figure of 28 TCF and the 1992 figure of 45 TCF (Table S2-15). Since 1992 a number of fields in Mexico have been re-evaluated with outside peer review. This has resulted in some reclassification of reserve categories of existing fields.

b. Growth

The NPC 2003 value for growth is about one-fourth of 1992 (Table S2-14). The 2003 study used the sum of probable and possible reserves published by PEMEX for existing fields as total growth for Mexico. The 1992 study did not document how their growth figure was calculated but since growth is related to proved reserves the fact that proved reserves were much larger in 1992 directionally indicates why growth was much larger as well. The NPC 1992 Mexico assessment used the U.S. Potential Gas Committee nomenclature for undiscovered gas resources where the category of Probable is equivalent to NPC 2003 Growth.

c. Conventional Undiscovered

The NPC 1992 Mexico assessment used the U.S. Potential Gas Committee nomenclature for undiscovered gas resources where the category of Possible is equivalent to NPC 2003 undiscovered conventional new fields. The NPC 2003 estimate is about three-fourths of the 1992 estimate for undiscovered conventional gas in Mexico (Table S2-14). The NPC 2003 estimate is actually 74% larger than 1992 for Mexico

Assessment Category	NPC 2003 (TCF)	NPC 1992 (TCF)	2003/1992 (%)
Proved without Chicontepec	28	45	62%
Proved Chicontepec	0	27	0%
Growth	22	87	25%
Conventional Undiscovered without Sabinas	66	38	174%
Conventional Undiscovered Sabinas	4	55	7%
Mexico Total without Chicontepec and Sabinas	**116**	**170**	**68%**

Table S2-15. Mexico Gas Resource Assessment Comparison excluding the Sabinas basin (Table S2-15). The NPC 2003 used the IHS Focus on Mexico and the USGS 2000 World Petroleum Assessment as the basis for undiscovered gas in Mexico. The NPC 1992 Study used a 1984 USGS assessment of 55 TCF of undiscovered gas in the Sabinas basin. The NPC 2003 estimates 4 TCF of undiscovered gas in the Sabinas basin. The explanation for the earlier optimism was the concept that Mesozoic carbonates in the Sabinas basin would have similar characteristics to the prolific producers in southeast Mexico. Further drilling did not support that hypothesis and thus the area was downgraded in more recent assessments.

d. Conclusions

The NPC 2003 estimate for Mexico gas is about one-half of the NPC 1992 estimate (Table S2-14). There are two significant differences which can be eliminated from consideration; namely the Chicontepec proved reserves and the Sabinas basin undiscovered gas. If these two factors are removed than the NPC 2003 is about 70% of NPC 1992 with most of the difference being related to larger growth in 1992 (Table S2-15). Since growth is related to the size of proved reserves then it is reasonable to assume that if proved reserves decline then growth should decline as well.

Given these explanations of factors which have changed since 1992, the overall assessment for Mexico is not greatly different from NPC 2003 to 1992.

IV. Methodology

A. Project Design and Process

1. Design Philosophy

Several factors affected the design of the 2003 NPC resource assessment process. First, the work had to be completed in about 5 months. Second, the implementation team consisted mainly of part-time industry volunteers supported by a few full-time core team members. Third, all data used had to be publicly available.

In September 2002, the core team outlined the resource assessment scope and plans and adopted an 80/20 rule in the assessment process. The 80/20 rule meant that approximately 80% of North America's natural gas resource was contained in approximately 20% of the geological basins, or plays. Therefore it was decided to concentrate effort on the assessment of this significant 20%. The remaining 80% of the basins or plays, representing just 20% of the resource, would be superficially examined and their assessments pro-rated based on more detailed assessments of nearby significant analogs.

Early on in the process, the resource team developed the concept of focus areas (Figure S2-72) to guide subsequent work. Clearly, the identification of focus areas was based on pre-existing assessments. After reviewing the major published North American assessments, it was decided to use USGS and MMS sources for the United States and CGPC sources for Canada. Other data sources that were consulted are listed in Figure S2-17. For the assessment of Mexico, the NPC purchased IHS's "Focus on Mexico: The Natural Gas Chain Technical Study."

Before work started, the core team designed a project plan organized around the work processes shown in Figure S2-73.

The best practice methodology, workshop, and modeling processes are described in the following sections.

2. Best Practice Teams

In order to be useful in modeling, there are many more quantities that need to be assessed besides total volume of natural gas. Moreover, there are often several different ways to estimate the underlying geoscience, engineering and commercial parameters. Best practice teams were formed to review the various industry methodologies and to make recommendations for the 2003 NPC study.

Before conducting the workshops, the best practice teams defined those major quantities, or factors, where industry expert opinions would be needed. The outline below gives an indication of the wide variety of data needed for the 2003 NPC study.

Besides total volume of undiscovered resource, additional parameters such as remaining number of undiscovered accumulations, maximum expected remaining accumulation size, chance of success, etc., were required.

Further quantification was then needed for input to economic modeling in order to forecast production and commercial resource. Production performance parameters such as recovery per well and initial rate, and cost parameters for such operations as drilling and completion are required. In addition, technology parameters

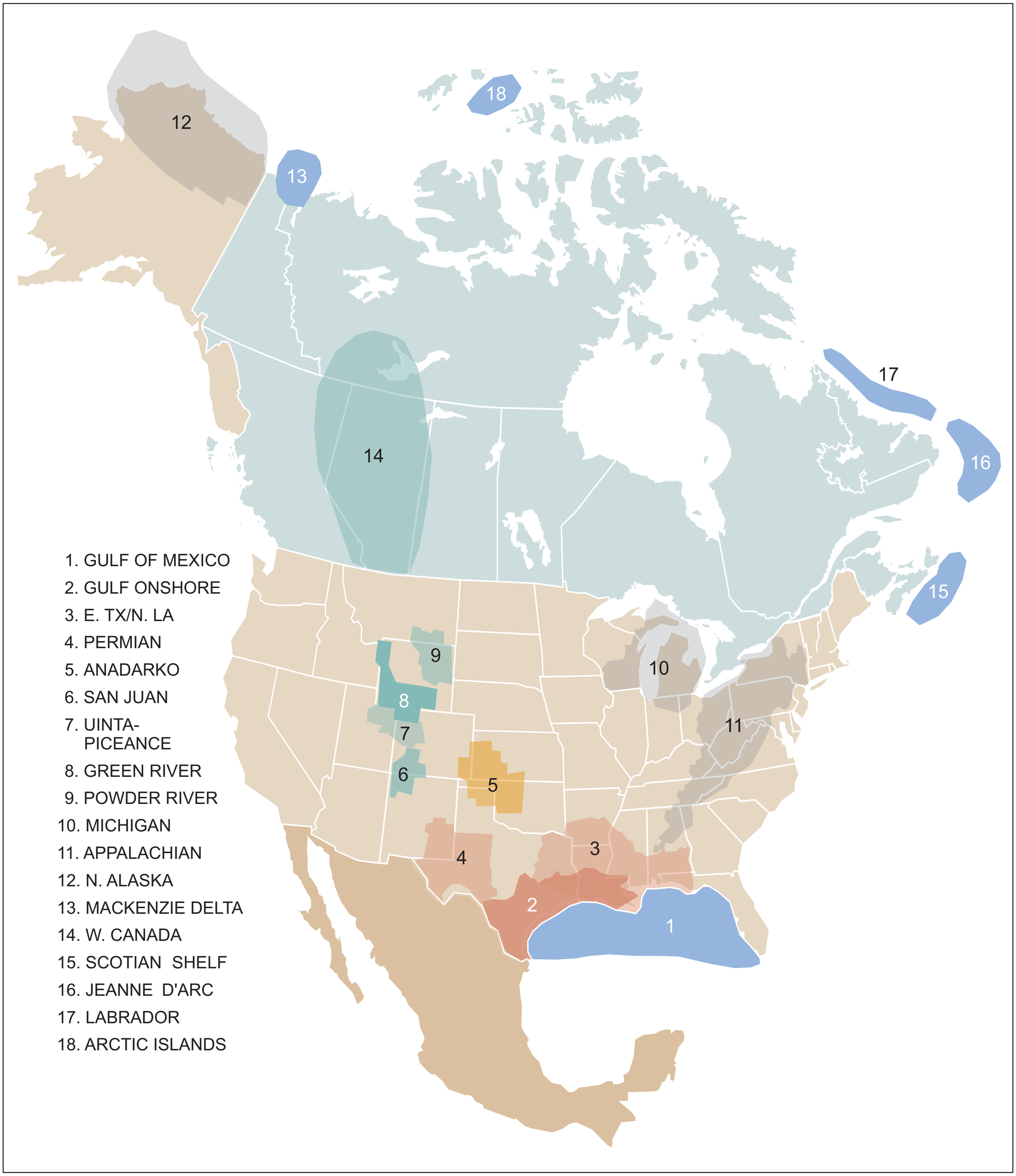


Figure S2-72. NPC Focus Areas

(e.g., annual improvement in stimulation technology), and access parameters (e.g., the delay caused by environmental review) were likewise needed for modeling input.

Having defined the required parameters, a series of questions was formulated in preparation for the workshops.

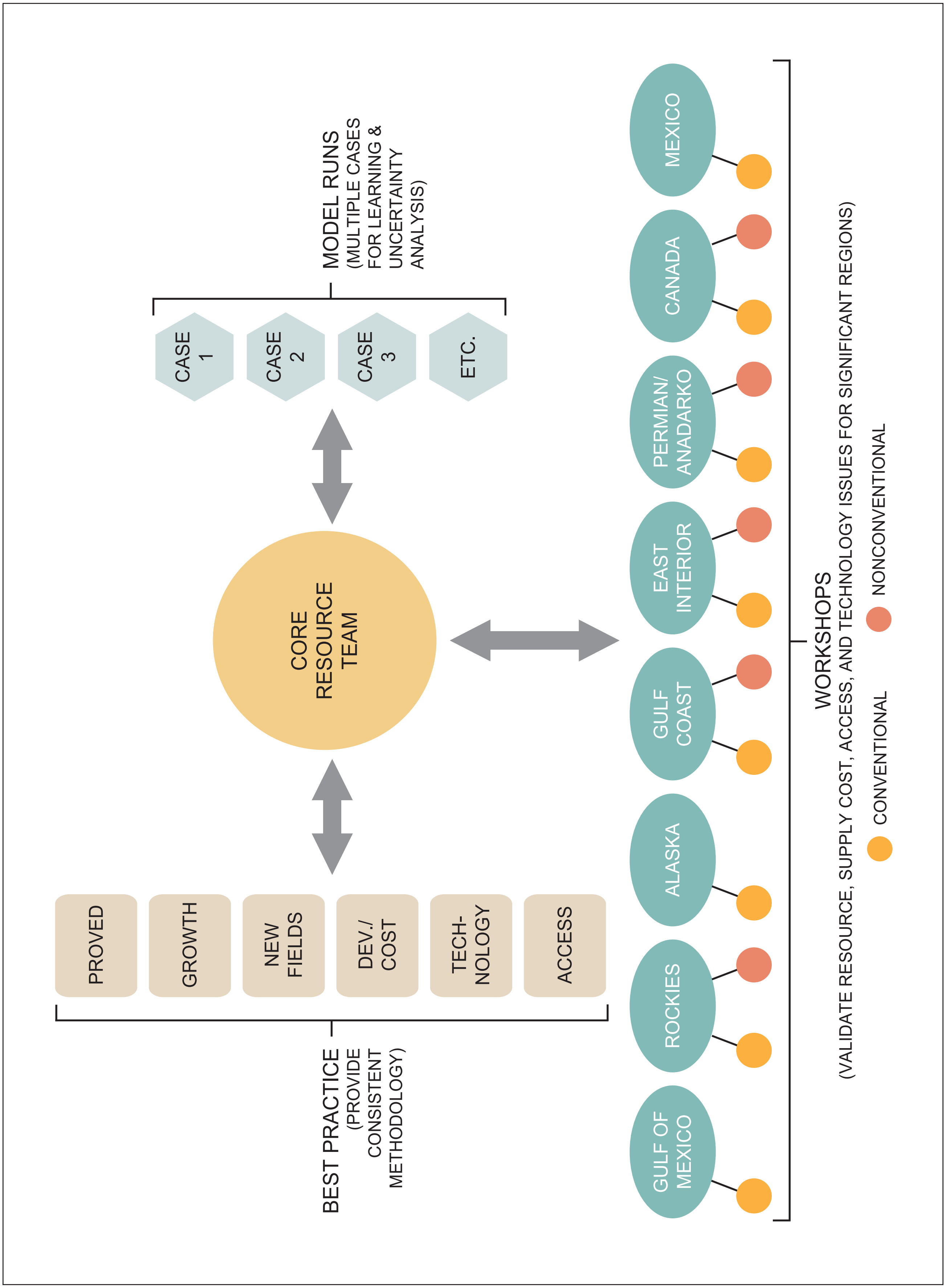


Figure S2-73. Resource Assessment Process

3. Industry Workshops

Given the time and manpower available, the NPC could not possibly conduct independent assessments. So it quickly became apparent that assessment of the significant 20% of basins, or plays, would be an exercise using a baseline of pre-existing publicly available assessments. The concept was to assemble expert industry groups to either validate the baseline assessments, or to revise the assessments in the light of new data, which could be publicly shared. It is an accepted fact that assessments are periodically revised when new ideas and data become available. This is particularly true for older assessments, such as the 1995 USGS assessments that have not yet been updated.

Once the methodology best practice had been chosen, and the required data defined, industry workshops were held for the focus areas shown in Figure S2-72. Each workshop typically lasted 2 to 3 days and was attended by up to 50 people. A list of the workshops is contained in Table S2-16.

The attending companies ranged from small private independents to large integrated multi-nationals. All other organizations are described as noncommercial in Table S2-16. Attending noncommercials included U.S. federal government bodies such as USGS, MMS, DOE, EIA, and state bodies such as the Alaska Division of Oil and Gas and the Texas Bureau of Economic Geology. In Canada, federal government agencies included NEB, GSC, and provincial agencies included AEUB and BC Ministry of Energy. Other noncommercials include U.S. organizations such as GTI, IPAMS, and Petroleum Association of New York, and Canadian organizations such as CGPC and CERI. In addition, EEA was represented at many of the workshops.

The Rockies and Western Canada Sedimentary Basin focus areas required repeat workshops to acquire additional quantification and clarity.

In terms of the workshop process, industry participants were asked to follow three main ground rules. The first involved limitation of discussions to non-proprietary facts. The second was concerned with materiality, such that only baseline assessment adjustments greater than 2 TCF, or in some cases 5 TCF, were subject to discussion. The third involved the consensus process whereby the industry experts could reach agreement on the change to baseline assessment subject to the first ground rule. This generally required the workshop facilitator to organize a voting process.

			Attendees	
Workshop	**Location**	**Date**	**Number**	**Affiliation**
Gulf of Mexico	New Orleans	Oct 22-24, 2002	50	10 companies, 3 noncomm.
Rockies 1	Houston	Oct 31-Nov 1, 2002	50	12 companies, 6 noncomm.
Alaska	Menlo Park	Nov 5-6, 2002	25	4 companies, 4 noncomm.
Gulf Coast Onshore	Houston	Nov 19-22, 2002	29	10 companies, 2 noncomm.
Canada 1	Calgary	Dec 3-6, 2002	49	16 companies, 5 noncomm.
Permian/Anadarko	Houston	Dec 10-11, 2002	17	7 companies, 3 noncomm.
Rockies 2	Denver	Dec 12, 2002	24	7 companies, 1 noncomm.
Eastern Interior	Reston	Jan 22-23, 2003	24	8 companies, 6 noncomm.
Rockies 3	Houston	Feb 6, 2003	12	5 companies, 0 noncomm.
Mexico	Houston	Feb 11-12, 2003	35	10 companies, 4 noncomm.
Nonconventional Reality Check	Houston	Mar 4, 2003	17	7 companies, 1 noncomm.
Canada 2	Calgary	March 10, 2003	33	14 companies, 6 noncomm.
Eastern Gulf of Mexico	Houston	Apr 16, 2003	8	4 companies, 1 noncomm.

Table S2-16. NPC Supply Workshops

Following collection of data from the industry workshops, the core team checked for internal consistency and sent detailed meeting notes back to the participants for comment. In some cases, such as calculation of the small field distribution (Section IV.C.2), the core team also made adjustments consistent with best practice methodology.

In addition to the initial resource assessment workshops, a number of reality check workshops were held following the first modeling runs. These were mainly designed to provide industry expert checks upon production engineering and operational constraints in areas where the model initially forecast major changes in the status quo, or in recent trends.

4. Data Sources

Many data sources were used in the 2003 NPC study. Some were major baseline studies such as the USGS, MMS, and CGPC assessments and the API JAS cost data. Others provided additional information or checks. The name of the data, what it is primarily used for and its access level is summarized in Table S2-17. Access level A is public domain data generally from government sources which has no restrictions, level B are commercial studies licensed or purchased by the NPC for use in this study, and level C are more restrictive conditions of use where the data can be used for this study but only summary information published.

B. Undiscovered Fields Assessment Methodologies

1. Methodology Summary

a. NPC Assessment Philosophy

The NPC could not redo a "grass roots" evaluation of North America in our study timeframe so we elected to use the most recent and best available assessments in the public domain as a starting point. For the onshore U.S. the United States Geological Survey (USGS) 1995 National assessment and some additional updates of selected basins were used. The Minerals Management Service (MMS) assessments were used for the U.S. offshore which includes the Gulf of Mexico, offshore Alaska, offshore Atlantic, and offshore Pacific. The Canadian Gas Potential Committee (CGPC) Report was used for Canada. For Mexico, the IHS Energy "Focus on Mexico" report and the USGS 2000 World Petroleum Assessment were used. The NPC methodology was to assemble industry and government experts and hold workshops to examine and modify, if necessary, the mean resource estimates for key large plays. Conventional accumulations were assessed for all areas of North America but nonconventional were assessed for the U.S. and Canada onshore only. Assessments of nonconventional resources in the offshore U.S., Canada offshore and frontier regions, and Mexico were not available. Conventional accumulations are characterized by distinct hydrocarbon-water contacts while nonconventional accumulations generally cover large areas and do not have distinct contacts (Figure S2-74). Nonconventional gas deposits include coal bed methane, fractured shale gas, and basin-centered tight gas.

b. Assessment of Undiscovered Fields for Conventional Plays

The geologic play is the most detailed unit of assessment. Plays are defined by geologic studies of sedimentary basins using existing wells and seismic data. Discovered fields are assigned to these plays by stratigraphic age. Thus geologic plays are units of rock with similar characteristics. The geographic limits of these plays are estimated and the sizes and numbers of discovered fields are compiled.

Prediction of numbers and sizes of undiscovered fields are done via "direct" or "indirect" methodologies.

In the "direct" method prospects, which are undrilled potential oil or gas fields, are mapped from seismic and well data. The size range of the potential hydrocarbon field is estimated using a volumetric approach, the number of prospects is counted and the wildcat success ratio is estimated based on past drilling history or analogy to a geologically similar area. There is uncertainty surrounding all of these parameters so they are given ranges and probabilities of occurrence. This then gives a range of undiscovered resource for a geologic play which when combined with all other plays can be statistically combined to give a range of total undiscovered potential for a basin, region, or country. This method works well when time and data allow detailed mapping of all potential prospects within an area. (This method is usually not feasible due to time and available data limitations.)

In the "indirect" method historical statistics are used to estimate the numbers and size ranges of undiscovered fields. All of the assessments the NPC used were of this type. There was some variation in methodology between the USGS, MMS, CGPC, and IHS Energy but the basic approach was similar. For plays with discovered fields

Name	Purpose	Usage Level*
2000 MMS GOM & Atlantic assessment	U.S. Offshore Undiscovered Oil & Gas Assessment	A
2000 MMS Offshore Alaska & Pacific assessment	U.S. Offshore Undiscovered Oil & Gas Assessment	A
1995 USGS National assessment	U.S. Undiscovered Oil & Gas Assessment	A
1999 NPC Study	U.S. and Canada Gas Assessment and Economic Forecast	A
2001 Canadian Gas Potential Committee report	Canada Gas Assessment	B
Nehring Significant Fields of United States	U.S. Field Size Database	C
2000 & 2002 U.S. Potential Gas Committee reports	U.S. Gas Assessments	C
Wood McKenzie Deepwater Gulf of Mexico field development summaries	Field development summaries deepwater GOM	C
API JAS Annual Drilling Cost Survey	U.S. Well Drilling Costs	B
Petroleum Services Association of Canada Well Cost Study	Canada Drilling Costs	B
CERI Potential Supply & Costs of Natural Gas in Canada	Canada Land Access and Costs	B
EIA Annual Survey Oil & Gas Lease Equipment and Operating Costs	U.S. Operating Costs	A
PEMEX Mutiple Service Contract Website	Mexico Drilling Costs	A
IHS "Focus on Mexico" Study	Mexico Gas Assessment and Costs	B
IHS Energy (Dwights) U.S. Production data	Well level production data	B
2000 USGS World assessment	Worldwide Undiscovered Oil & Gas Assessment	A
EIA reports	Production & Reserves Statistics & Reports	A
2002 DOE Greater Green River and Wind River Basins Study	Gas assessment, land access and economics	A
2003 EPCA Study	Rockies federal land access and assessment	A
Hayden-Wing and Associates – Species habitat study in Rockies region for NPC 2003	Rockies land access stipulations	B
EEA Gas Supply Review	U.S. Historical and Current Gas Production	B

* A = unlimited usage; B = broad usage providing source credited; C = usage limited to data aggregations.

Table S2-17. NPC Data Sources

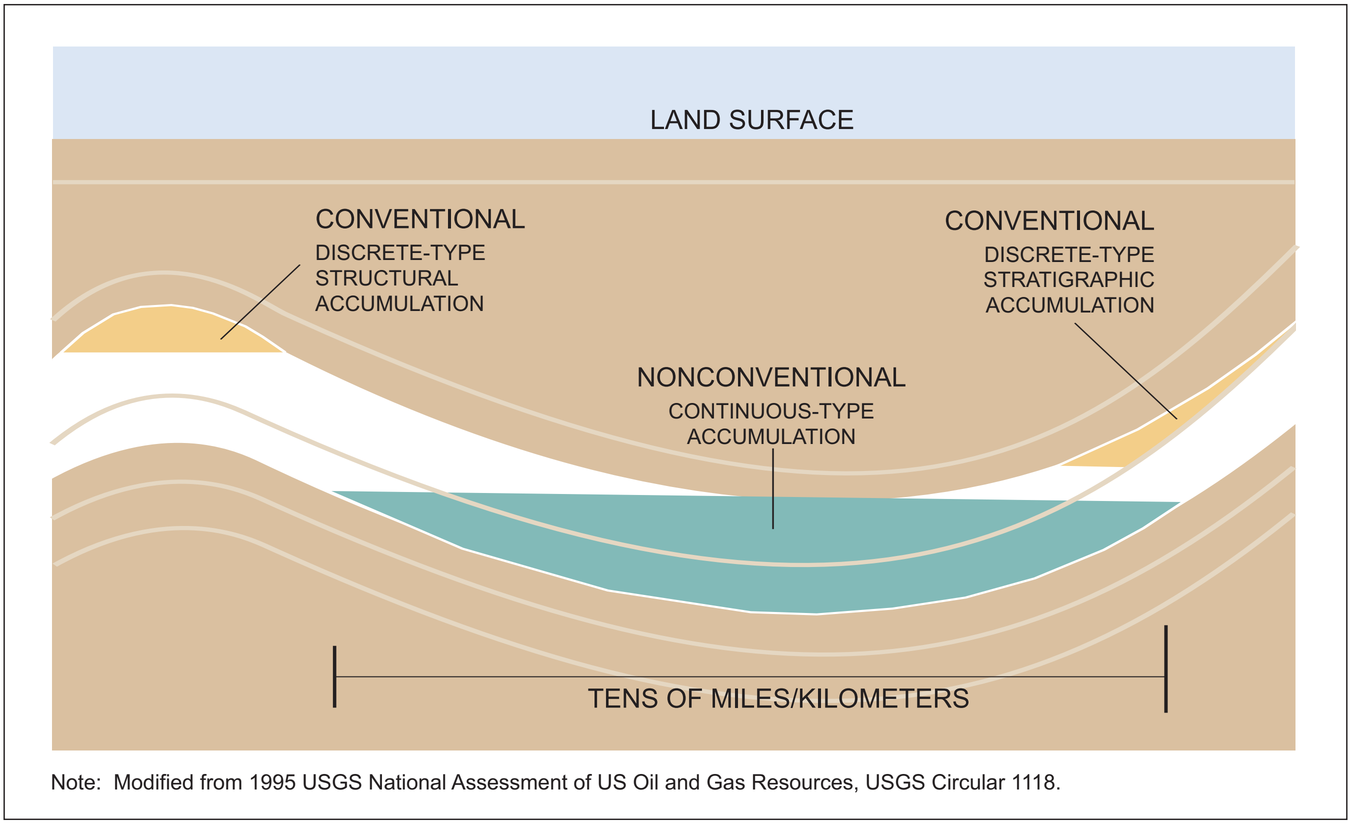


Figure S2-74. Conventional vs. Nonconventional Accumulations

the sizes and discovery sequence of those fields is carefully compiled (Figure S2-75). Since the numbers of future prospects is not known this must be estimated. One way to estimate numbers of prospects is to examine a mature portion of the play and derive a "prospect density" and apply that to other portions of the play area. Another method to estimate numbers of prospects is to take the yearly wildcat drilling count for that play and multiply it by the time of interest of the assessment (i.e., 30 years). Sizes of undiscovered fields are usually considered to be similar to sizes of recent discoveries in the play. This usually reduces in average size with time in most known basins and plays. Since the numbers and sizes of future fields are uncertain these are given ranges and then combined in a statistical "Monte Carlo" program which results in a range of undiscovered resource. Common statistics include P90 (90% chance there is this much or more undiscovered resource), mean (the average amount of undiscovered resource), and P10 (there is a 10% chance there will be this much or more undiscovered resource). P10 is the largest number, the mean is smaller and P90 is the smallest of the three. These individual plays are then statistically summed by basin, region, and country.

c. Assessment of Nonconventional Plays

Nonconventional gas plays differ from conventional plays in several ways. Conventional accumulations are generally smaller in areal extent and have obvious traps and seals with well delineated hydrocarbon-water contacts. Nonconventional plays generally cover a larger area than a conventional field and do not have obvious hydrocarbon-water contacts. These are often in close proximity to source rocks (or contained within source rocks in the case of coal bed methane and fractured shale gas) and often are abnormally pressured. The recovery percentage of gas in place is usually low, primarily due to poor reservoir quality (low permeability). Within a given nonconventional play well rates and ultimate recovery vary widely, usually related to the extent of natural fracturing which enhances permeability.

The methodology for assessment of undiscovered gas from nonconventional hydrocarbon accumulations differs from that used for conventional accumulations. The USGS methodology outlines the areal extent of the nonconventional play and divides it into a grid of "cells," the size of which approximates a single well drainage area. The factors required for assessing an nonconventional play are: its area, cell size, number of

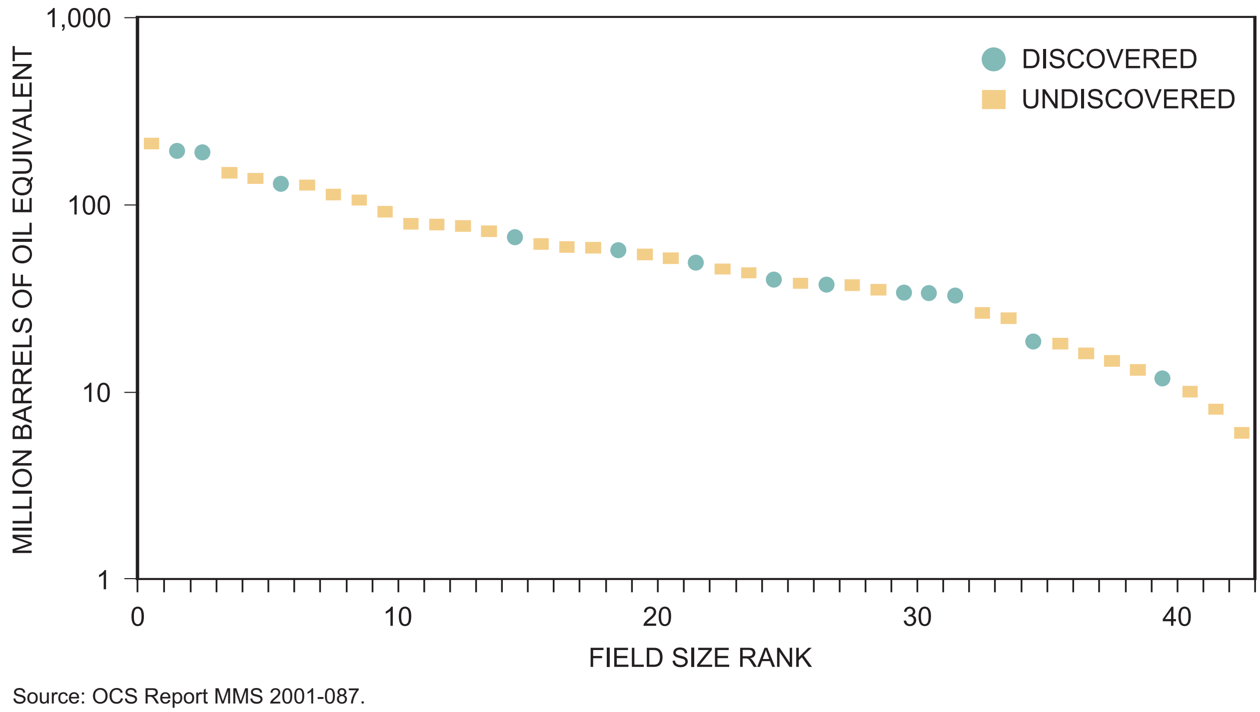


Figure S2-75. Example of a Field Size Distribution

untested (undrilled) cells within the play outline, the average (and range) of gas recovery per cell, and the average success rate of wells drilled within the play boundary (Figure S2-76). There is uncertainty so the input parameters are given ranges rather than single values. These factors are combined probablistically which results in a range of undiscovered gas. The mean is used as the single value most representative of the undiscovered potential of the play.

2. USGS Assessment Methodology (Onshore U.S.)

The USGS assessment of undiscovered conventional resources is conducted at the play level (and more recently at the assessment unit level which is a similar concept) and requires the estimation of the sizes and numbers of undiscovered oil and gas accumulations along with an estimation of play risk where the play has not yet been proven. A full discussion of the USGS methodology can be found in the 1995 National Assessment of United States Oil and Gas Resources, U.S. Geological Survey Circular 1118, 1995. The USGS assessment methodology employs a Truncated Shifted Pareto model to describe the size-frequency distribution of the population of undiscovered oil and gas fields. The Truncated Shifted Pareto model is fit to estimated median and largest (at 5% probability) undiscovered fields within the postulated population of undiscovered fields. The model is "truncated" at the largest predicted accumulation in the distribution. In play trends with discovered fields, the Pareto model was fit to the known accumulations in chronological order of discovery, to the first, second, and final thirds of the discovered accumulations. These distributions, plotted by thirds, show how the size distributions have changed through time as a function of exploration maturity.

The Truncated Shifted Pareto model describes a distribution in which ever-increasing numbers of accumulations occur in successively smaller size classes. The distribution is called shifted because its origin is moved to a minimum accumulation size. The USGS uses a minimum size of 1 MMBO or 6 BCFG. At the play level, no future resource potential is assessed for fields smaller than 6 BCF. Yet, in some areas smaller fields are being actively explored for and developed. This trend is likely to continue into the foreseeable future, with increasingly smaller fields being targeted. The USGS estimates numbers of fields smaller than

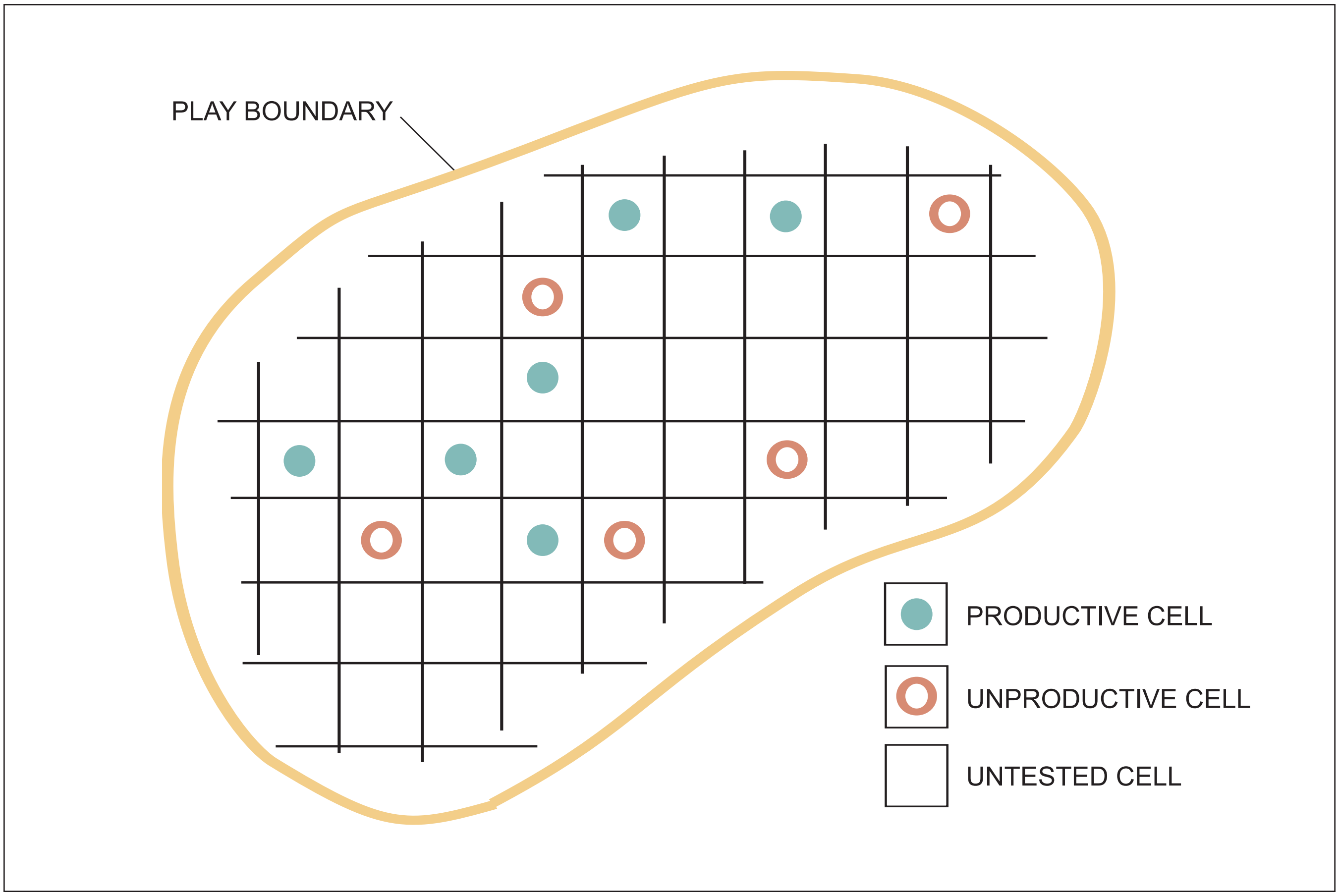


Figure S2-76. USGS "Cell-Based" Assessment for Nonconventional Hydrocarbon Accumulations

6 BCF at the province level (which is usually a geologic basin).

3. Canadian Gas Potential Committee Assessment Method (Canada)

The CGPC assessment of undiscovered conventional resources, like the USGS assessment, is conducted at the play level. The CGPC methodology also provides for a systematic integration and analysis of the geologic factors that are responsible for the occurrence of oil and gas. The size and number of undiscovered hydrocarbon accumulations, as well as the quantity of these estimated resources are provided. The assessment methodologies are thoroughly documented in the CGPC report, Natural Gas Potential in Canada - 2001.

The principal assessment tool used by the CGPC is the Petroleum Exploration and Resource Evaluation System (Petrimes), developed by the Geological Survey of Canada (Lee and Tzeng, 1993). The basic concept employed in the program is that the discovered pools in an exploration play make up a size-biased sample that can be used to describe the complete population of the pools in the play. The size bias results largely from economic truncation in the reporting of reserves. In most cases the distribution of the size of pools in a play is approximately log-normal and this assumption is used in the analysis. The sample represented by the discovered pools, combined with an estimate of the total number of pools in the play is used to define the total distribution. This information is entered into Petrimes and the program calculates a log-normal distribution, where gaps in the distribution are expected to be filled with undiscovered pools. In this manner the program estimates the undiscovered potential for a play and the size ranges for each undiscovered pool. Solutions are not unique and geological judgement is applied to select the most appropriate case. Particularly important is a judgement of whether or not the largest field has been found and to ensure that the distribution includes pools in the smaller size ranges that may not be represented in the discovered pool sample. In the CGPC application of this methodology there is no arbitrary lower limit of smallest pool size assessed. The number of small pools is the result of geologic judgement, not statistical method.

In cases where no discoveries have been made, resource sizes are estimated from information describing the area and number of potential prospects, ranges of net pay, porosity, and hydrocarbon saturation. This process solves for reservoir volumes using probability distributions for input variables. Subjective assessments utilizing this approach were made for Eastern Canada and the West Coast Play Group.

4. MMS Assessment Method (Offshore U.S.)

The MMS assessment of undiscovered conventional resources is also conducted at the play level and provides estimates of the sizes, numbers and types of oil and gas accumulations along with an estimation of play risk. The MMS assessment methodology is similar to the CGPC. The MMS utilizes software adapted from Petrimes and develops a log-normal model for the size-frequency distribution of the population of oil and gas accumulations. Details of the MMS methodology for predicting future oil and gas resources in the Gulf of Mexico can be found in Lore, G.L. and others, 2001 (http://www.gomr.mms.gov/homepg/offshore/gulfocs/assessment/assessment.html).

5. IHS Energy Assessment Method (Mexico)

The IHS assessment was done at the basin level which includes multiple plays. Thus there is a separate assessment of the Burgos Basin onshore, Burgos Basin offshore, Sabinas Basin, etc. IHS uses proprietary software to take the discovered field sizes for the basin and estimates numbers and sizes of undiscovered fields (IHS Energy Group, 2001).

6. References

Gautier, D. L. and others (eds), 1996. National Assessment of United States Oil and Gas Resources – Results, Methodology, and Supporting Data. United States Geological Survey Digital Data Series DDS-30, one CD-ROM, Release 2.

IHS Energy Group, 2001. Focus on Mexico: The Natural Gas Chain – Opportunities Arising from Changing Policies.

Lore, G.L. and others, 2001. 2000 Assessment of Conventionally Recoverable Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 1999, OCS Report MMS 2001-087.

C. Small Fields Estimation

The undiscovered resource base is characterized by the NPC in terms of the number and size of undiscovered fields. This characterization is necessary for the economic evaluation of these future fields. Many of the traditional gas plays in the U.S. and Canada have reached a mature phase of exploration and most future fields are expected to be small. Assuming that a portion of these small fields can be commercially developed, it is important to understand the resource potential associated with these small fields. Because of economics, the number of discovered small fields tends to be greatly under-reported. Non-economic discoveries tend to be reported as dry holes and even if reported as a hydrocarbon show, the size of the discovery is not known. As a result, the discovered field database is deficient in the small field sizes. Because of this, traditional assessment approaches cannot be used for small fields and statistical methods must be used. The assessments that form the basis of the NPC study employ slightly different methodologies to estimate undiscovered small fields. These methodologies will be explained as well as the methodology employed by the NPC to estimate small field resources.

1. USGS Assessment Method

The USGS assessment of undiscovered conventional resources is conducted at the play level and requires the estimation of the sizes, numbers, and types of oil and gas accumulations along with an estimation of play risk. A full discussion of the USGS methodology can be found in the 1995 National Assessment of United States Oil and Gas Resources, U.S. Geological Survey Circular 1118, 1995.

The Truncated Shifted Pareto model describes a distribution in which ever-increasing numbers of accumulations occur in successively smaller size classes. The distribution is called shifted because its origin is moved to a minimum accumulation size. The USGS uses a minimum size of 1 MMBO or 6 BCFG. At the play level, no future resource potential is assessed for fields smaller than 6 BCF. Yet, in some areas smaller fields are being actively explored for and developed. This trend is likely to continue into the foreseeable future, with increasingly smaller fields being targeted. The USGS estimates numbers of smaller fields at the province level but these resources are not allocated to plays and so development economics can not be evaluated.

The USGS makes probabilistic estimates for fields smaller than 1 MMBO or 6 BCF at the Province level. The method is described in Gautier, et. al., 1995, and by Root and Attanasi, 1993. The estimates are based on extrapolations of numbers of fields using a log-geometric model. The minimum size estimates are for accumulations down to 32,000 barrels of oil and 192,000 cubic feet of gas. The Province level estimates thus include these small fields.

2. NPC Method on USGS Assessment Areas

For the current study, the NPC developed a new method of assessing small field potential at the individual play level. This expands upon the USGS approach, which developed only province level small field assessments. In order to do this, EEA created several processing programs to deal with each assessing organization's data (USGS, MMS, and CGPC). These programs allowed the NPC to evaluate historical discoveries in each play, incorporate modified NPC play level assessments where necessary, and develop the play level small field assessments.

In the case of the USGS onshore assessment, the procedure for evaluating the undiscovered field size distribution and small field assessment at the play level was as follows.

For field size classes of 1 million barrels of oil equivalent (MMBOE) or more, the NPC evaluated the USGS assessments and either agreed with the USGS assessments of undiscovered BOE or modified it, based upon the results of the assessment workshops. The undiscovered assessment in MMBOE for field sizes of 1 MMBOE or more was then assigned to field size classes using an Arps-Roberts approach. This was possible because the number of discovered fields in each size class is known, and the total resource assessment is known. The use of the Arps-Roberts approach by the NPC results in a different undiscovered field size distribution above 1 MMBOE for each play then developed by USGS.

The Arps-Roberts methodology employs a negative exponential equation that predicts the number and size of undiscovered fields based on the ratio of the area of the discovered fields in each size class compared to the area of the basin and the number of exploratory wells that have been drilled. Discovered fields are assigned to size classes where the next larger class is twice the size of the previous class. An exploratory efficiency factor is included in the equation that controls to what extent the larger discoveries are made earlier.

The number of fields in classes smaller that 1 MMBOE was estimated by evaluating the ratio of the number of fields in successive field size classes above 1 MMBOE. A "linear ratio" model was developed to accomplish this, as described below.

To correct for economic truncation, a function is derived to estimate the number of fields below the mode by applying a fit to the Arps-Roberts estimates above the mode. The function is derived by fitting a linear equation to the ratio of the number of fields between successive size classes. When there are more than 10 discoveries in a size class the Arps-Roberts values are used. The fitted equation is used below the mode when there are less than 10 discoveries. An additional constraint is that the ratio is not allowed to go below 1.05, ensuring that there are always a greater number of undiscovered fields in successively smaller size classes. This technique is illustrated in Figure S2-77. The Arps-Roberts equation is used to calculate the number of fields remaining to be discovered in each size class. The ratio of the number of fields between successive class sizes is plotted and shown as boxes in Figure S2-77. In size class 12 there are 1.5 times as many fields as in class 13. In class 13 there are 2 times as many fields as in class 14. A linear, best-fit equation is shown by the green line. The NPC calculated values are shown as the red line. The NPC used Arps-Roberts calculated values when there are more than 10 discoveries per size class. For smaller size classes the best fit equation was used until the calculated value was less than 1.05. This methodology generates a small field fraction (size classes 5 and below) similar to the Permian Basin Morrow sandstone play shown in Figure S2-78. Each successively smaller field size class is expected to have more accumulations than the preceding size classes.

3. Canadian Gas Potential Committee Assessment Method

The CGPC assessment of undiscovered conventional resources, like the USGS assessment, is conducted at the play level. The CGPC methodology also provides for a systematic integration and analysis of the geologic

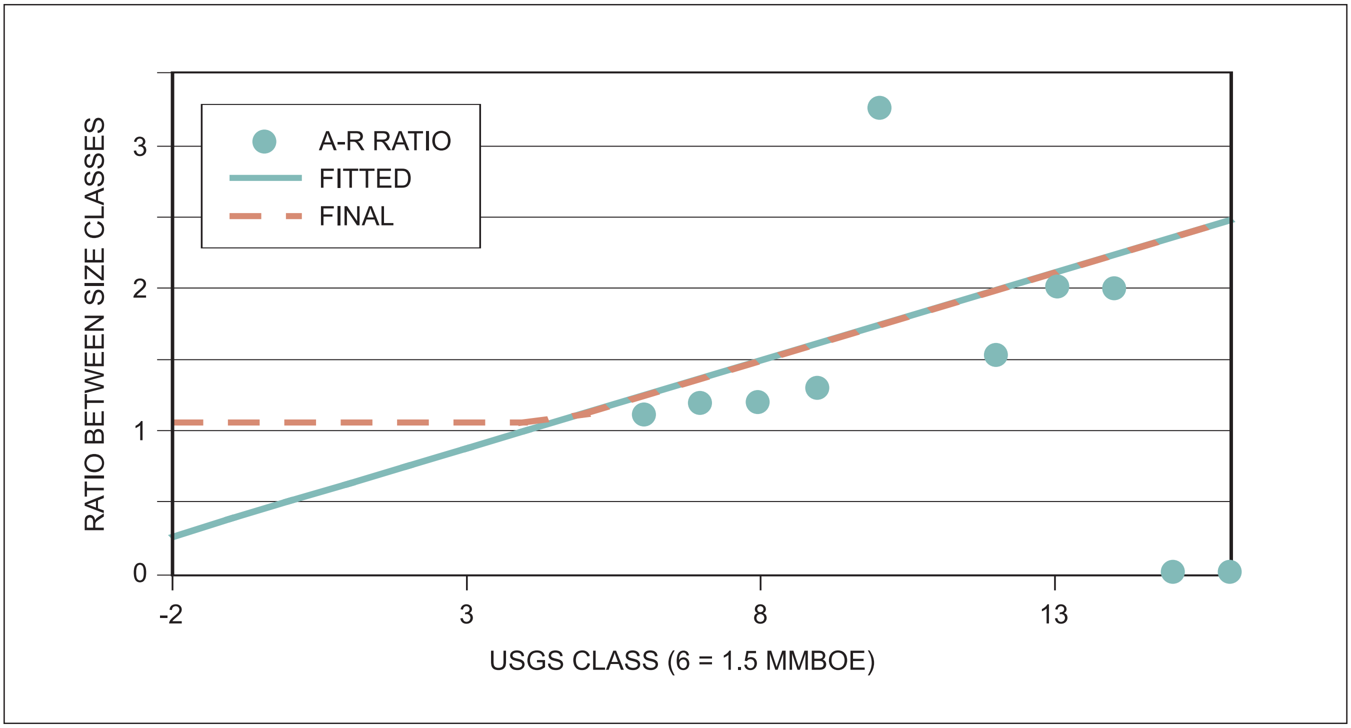


Figure S2-77. Modified Arps-Roberts Methodology – Permian Basin Morrow Play Example

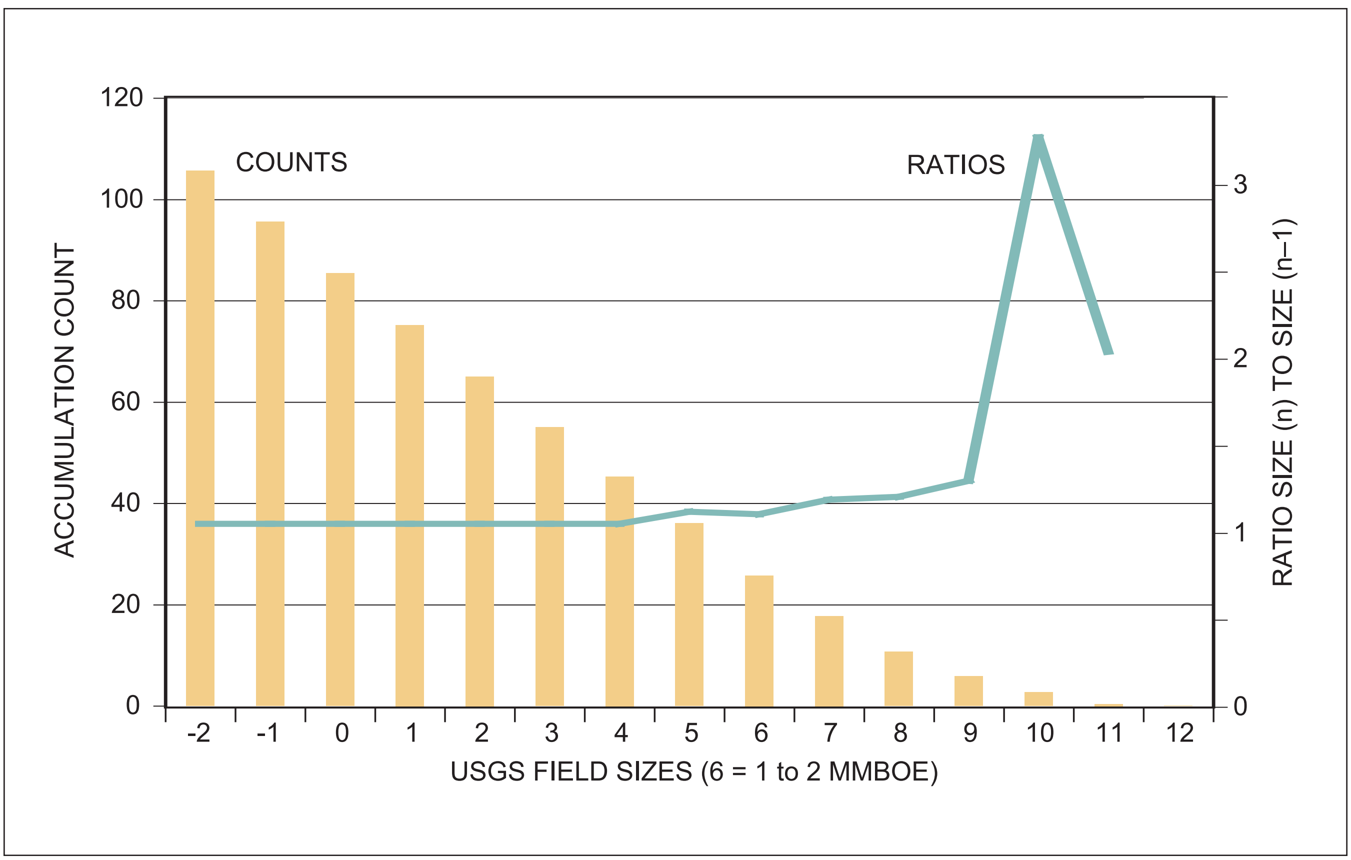


Figure S2-78. The Arps-Roberts Discovery Process Methodology for the Permian Basin Morrow Sandstone Play factors that are responsible for the occurrence of oil and gas. The size and number of undiscovered hydrocarbon accumulations, as well as the quantity of these estimated resources are provided. The assessment methodologies are thoroughly documented in the 2001 CGPC report.

The CGPC employed Arps-Roberts methodology in plays with numerous existing accumulations. Most of these are Cretaceous plays in the Western Canada Sedimentary Basin which are stratigraphically trapped thin sands. The CGPC applied a second-degree polynomial to fit the ratio of the number of fields between size classes, which differs from the NPC approach. This results in fewer small accumulations estimated than the linear fit employed by the NPC.

4. NPC Method on CGPC Assessment Areas

The NPC adopted the CGPC assessment where Arps-Roberts calculations were applied. In plays where the Petrimes log-normal distribution yielded a diminishing number of small fields in successively smaller field size classes, the NPC used the same modified Arps-Roberts method as used to correct the USGS assessments. A function is derived by fitting a linear equation to the ratio of the number of fields between successive size classes. This function is then used to estimate the number of small fields in field size classes below 1 MMBOE. This is done to ensure that there are always more fields in each smaller field size class and to provide consistency of approach.

5. MMS Assessment Method

The MMS assessment of undiscovered conventional resources is also conducted at the play level and provides estimates of the sizes, numbers and types of oil and gas accumulations along with an estimation of play risk. A full discussion of the MMS methodology can be found in Lore, et. al., 2001. The MMS assessment methodology is similar to the CGPC process for most plays. The MMS utilizes software adapted from Petrimes and develops a log-normal model for the size-frequency distribution of the population of oil and gas accumulations.

6. NPC Method on MMS Assessment Areas

In plays where the log-normal distribution yielded a diminishing number of small fields in successively smaller field size classes, the modified Arps-Roberts method described above was used to correct the MMS assessments. A function is derived by fitting a linear equation to the ratio of the number of fields between successive size classes. This function is then used to estimate the number of fields in the smaller field classes. This is done to ensure that there are always more fields in each smaller field size class and to provide consistency of approach. The NPC small field fraction is shown in Table S2-18.

D. Reserve Growth

Reserve growth is the increase observed over time in the estimated ultimate recovery (EUR = remaining proved reserves plus cumulative production) from fields or group of fields. Numerous labels are attached to this phenomenon – reserves growth, growth to known, reserves appreciation, ultimate recovery appreciation (URA), and inferred reserves. Reserve growth can be divided into two major categories. The first involves the development of resources known to be present to a reasonable degree of certainty, but not with enough confidence to be classed as proved. The second involves the discovery of new resources from the extension of the known field limits and/or discovery of new pools in the field. In addition, reserve growth can occur by application of improved completion technologies such as fracture stimulation and improved recovery methods such as waterflood or other forms of pressure maintenance (particularly in oil fields).

The overall technical resource assessment must include an estimate of this future growth. In the previous 10 years, most of the additions to the U.S. proved reserve base have been from reserves growth, rather than new discoveries (EIA U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2001 Annual Report). Growth has historically (1977-1995) repre-

Country	Undiscovered Conventional Including Small Fields (TCF)	Small Field Volume (%)
United States	687	11
Canada	219	25
Mexico	70	18

Table S2-18. Summary of NPC Small Field Adjustments by Country sented 74% of U.S. proved natural gas reserve additions.

Proved reserves as reported in corporate financial statements, commercial transactions, and to governmental regulatory bodies reflect high confidence that those volumes are economically recoverable. Thus, published estimates of proved reserves are typically conservative. Successful drilling in and around existing fields results in reserves growth.

Several different methodologies have attempted to model resource appreciation since J.R. Arrington, a Canadian petroleum engineer, first publicly recognized it in 1960. Statistical analysis of past changes in proven reserves can provide an extrapolation methodology to define a growth function (M. King Hubbert growth curves for ultimate production, 1956, 1967). The USGS and others have utilized similar methodologies to estimate future resource appreciation. In general, most equations have a similar form: high rates of reserve appreciation during early field life, followed by lower rates and finally no additional growth as the field is fully developed (Figure S2-79).

1. NPC Methodology

This study adopted the modified EEA cohort analysis methodology to determine growth for each of the regions where data were available. This methodology uses historical well-level EUR data by discovery age, basin, and depth for conventional resources. For each well, the age of the completion is related to the field discovery date and an EUR is calculated. The completions are divided into depth groupings (i.e., 5,000-10,000 feet, 10,000-15,000 feet, etc.) The total number of completions is divided into ten groups (cohorts) sorted by date of completion. The average EUR for each of these ten groups is then calculated. This provides a view of the change in EUR over time segregated by depth and field discovery period for each region. This methodology is most statistically reliable where there are a large number of completions.

An average growth percentage was thus derived by extrapolating these trends into the future until an assumed economic cutoff is reached. This gave a future growth percentage for the region for the given depth interval. The projected slopes were compared to historical field EUR data and region trends. In an

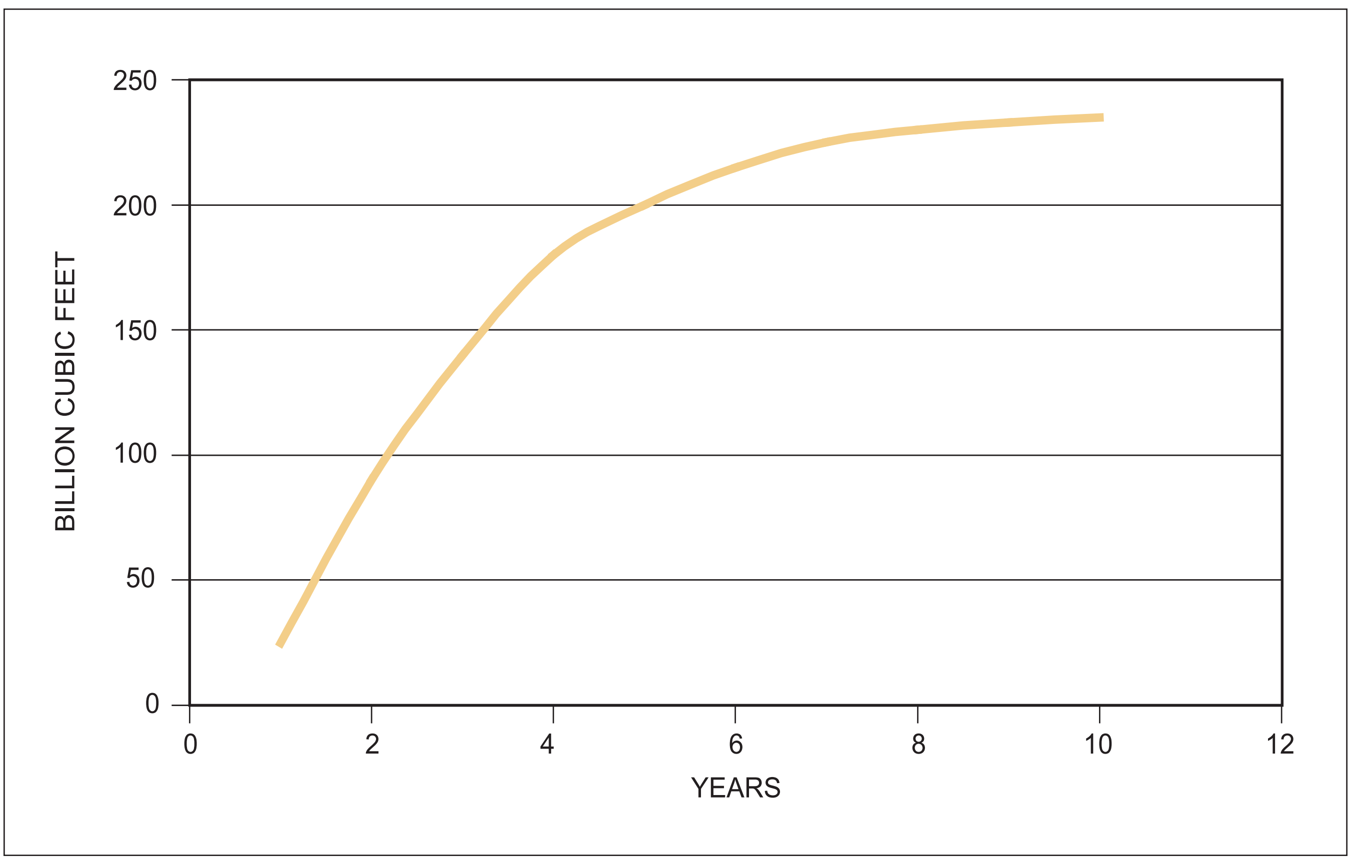


Figure S2-79. Reserve Growth vs. Time

additional reality check, best-fit linear regressions were performed using the same cohort data points on several regions containing adequate data. In the example shown in Figure S2-80, cohorts 0-10 are history and 10-20 are future projections. The horizontal line at 1.0 BCF/Completion represents the economic limit. The colored lines (51-60, 61-70, etc.) represent fields discovered between 1951-1960, 1961-1970, etc.

A region's future growth percentage is then multiplied with region's EUR (derived from EIA/AGA reserves and production data to arrive at growth in TCF).

EEA applies the projected growth for each region to the economic model by using the expected future number of completions/well and the average EUR/well.

2. Results

The total growth for North America is estimated to be 277 TCF, which is 102% of the remaining proved reserve base of 272 TCF. The total growth for U.S. lower-48 is 204 TCF, which accounts for 74% of the total for North America. Growth in the current study applies only to conventional deposits.

The Gulf Coast Onshore has the largest growth (60 TCF) and the Gulf of Mexico is second with 55 TCF. These two super-regions combine for 41% of the North America total (Table S2-19).

3. Uncertainties

Growth is an important part of the North American gas resource base. Growth is associated with producing fields and may often lead to production at lower additional investment than for undiscovered resource. The NPC considered several options for calculating growth but decided that the EEA cohort method was the most appropriate given the available public domain data.

Every technique used to calculate future growth employs assumptions. In the cohort methodology, one of the key assumptions is that in a given field, or region, the EUR per completion tends to decline over time as thinner and/or lower quality reservoirs are

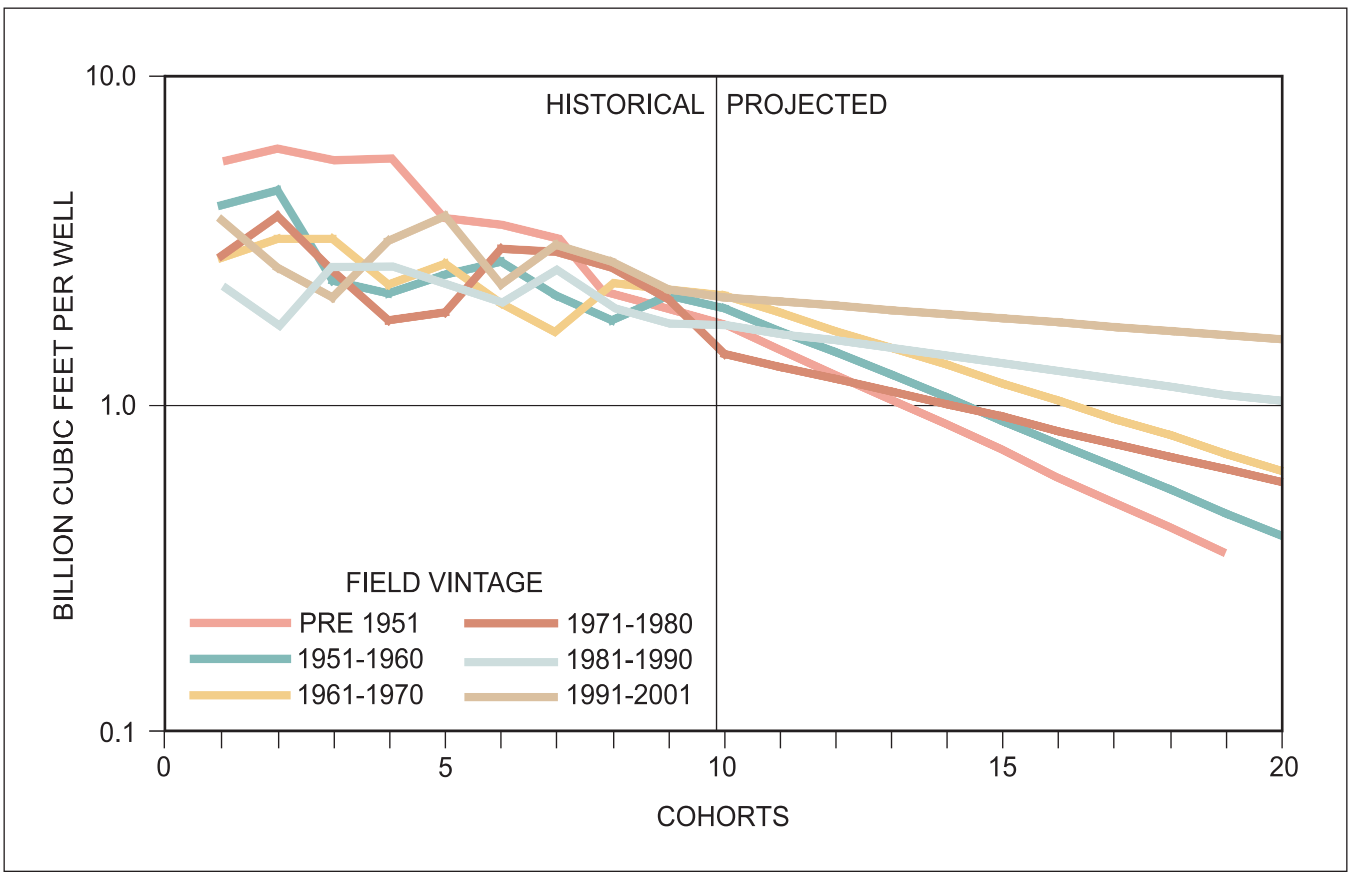


Figure S2-80. Example of NPC Cohort Growth Analysis

Super-Region	Growth (TCF)
Alaska	22.0
West Coast Onshore	3.2
Great Basin	1.0
Rockies	25.5
West Texas	21.5
Gulf Coast Onshore	60.2
Midcontinent	32.3
Eastern Interior	4.7
Gulf of Mexico	54.6
U.S. Atlantic Offshore	0.0
U.S. Pacific Offshore	1.0
WCSB	28.1
Arctic Canada	0.0
Eastern Canada	0.2
Canada Atlantic	0.4
British Columbia	0.0
Mexico	22.5
Total	**277.2**
U.S. Lower-48	204.0
United States	226.0
Canada	28.7
Mexico	22.5

Table S2-19. Growth to Known By Super-Region and Country

developed. Another assumption is that new completions activity will occur only as long as it is economic to do so. It is necessary to predict the future EUR/completion economic cutoff to be able to project the trends and get future growth. If the assumed economic cutoff is not correct, then the accuracy of the growth projection will be affected. Future technology and market conditions affect the actual future economic cutoff. In addition, there is some subjectivity in choosing the projected slope of the cohorts, which strongly affects the calculation.

It is not strictly valid to compare growth estimated by different methodologies. One reason is that the reserve estimate for the same field may differ between groups (e.g. EIA versus MMS). It is probably more valid to compare the sum of proved reserves and projected future growth to understand the range of uncertainty of various published estimates.

V. Technical Resource Charts

This section contains summary charts of technical resources by country (Table S2-20), super-region (Table S2-21), and region (Table S2-22). Additional resource assessment data can be found in the CD-ROM that the NPC is making available as part of the study documentation.

	Cumulative Production	Proved Reserves	Growth*	Undiscovered Conventional	Undiscovered Non-conventional	All-Time Technical Resource
Lower-48 Onshore	762	145	148	188	282	1,525
Lower-48 Offshore	166	30	57	298	0	551
Alaska	11	9	36	201	57	314
United States	939	184	241	687	339	2,390
Canada	127	60	69	219	50	525
Mexico	48	28	22	70	0	168
North America	1,114	272	332	976	389	3,083

* Growth includes 277 TCF of reserve appreciation and approximately 55 TCF of discovered, non-producing fields in frontier areas.

Table S2-20. North American Technical Resource Base by Country – Current Technology (Trillion Cubic Feet)

Super-region	Discovered Remaining			Undiscovered						Total Technical Resource
	Proved Reserves	Growth to Proved Reserves /1	Total Discovered Remaining	Conventional Potential	Nonconventional Potential: Shale	Coalbed	Tight /2	Noncon. Total	Total Undiscovered Potential	
Alaska	8.8	36.4	45.2	201.0		57.0		57.0	258.0	**303.2**
West Coast Onshore	2.6	3.2	5.8	10.4	0.3	0.7	11.8	12.8	23.2	**29.0**
Great Basin	1.0	1.0	2.0	2.7				0.0	2.7	**4.7**
Rockies	49.7	25.5	75.2	36.3		38.0	134.6	172.6	208.9	**284.1**
West Texas	16.4	21.5	37.8	19.6	7.0			7.0	26.6	**64.5**
Gulf Coast Onshore	37.5	60.2	97.7	77.1			8.5	8.5	85.6	**183.3**
Mid-continent	24.0	32.3	56.3	26.9		4.9		4.9	31.8	**88.1**
Eastern Interior	13.7	4.7	18.4	15.5	27.4	14.2	34.7	76.3	91.8	**110.2**
Gulf of Mexico	29.2	55.3	84.4	244.4				0.0	244.4	**328.8**
U.S. Atlantic Offshore	0.0	0.0	0.0	32.8				0.0	32.8	**32.8**
U.S. Pacific Offshore	0.6	1.0	1.7	20.7				0.0	20.7	**22.3**
WCSB	57.5	28.1	85.6	92.6	16.7	29.1		45.8	138.4	**223.9**
Arctic Canada	0.0	24.6	24.6	46.4				0.0	46.4	**71.0**
Eastern Canada Onshore	0.4	0.2	0.6	1.7		3.9		3.9	5.6	**6.2**
Eastern Canada Offshore	2.2	15.3	17.5	67.6				0.0	67.6	**85.1**
Western British Columbia	0.0	0.0	0.0	10.9				0.0	10.9	**10.9**
Mexico	28.2	22.5	50.6	70.4				0.0	70.4	**121.0**
North America total	271.7	331.8	603.5	977.0	51.4	147.8	189.6	388.8	1,365.8	**1,969.3**
United States	183.5	241.1	424.5	687.4	34.7	114.8	189.6	339.1	1,026.5	**1,451.0**
Canada	60.1	68.2	128.4	219.2	16.7	33.0	0.0	49.7	268.9	**397.2**
Mexico	28.2	22.5	50.6	70.4	0.0	0.0	0.0	0.0	70.4	**121.0**

/1 Reserve appreciation and stranded fields. Includes 55 Tcf of stranded fields, primarily in Alaska, Arctic Canada, and Eastern Canada Offshore.
/2 Includes 14.5 Tcf of Low-Btu gas in Rockies

Table S2-21. North American Technical Resource Base by 17 Super-Regions – Current Technology (Trillion Cubic Feet)

NATURAL GAS ULTIMATE RECOVERY AND UNDISCOVERED RESOURCES AS OF 1/1/02

(TCF dry; total gas)

(Technically recoverable resource)

Entire resource including no access portion

Region Number	Acronym	Region Name	NPC Super Region	Discovered/proved: Cumulative Production	Discovered/proved: Proven Reserves	Discovered/proved: Ultimate Recovery	Discovered Undeveloped	Unproved: Old Field Appreciation	Unproved: New Fields	Unproved: Shale	Unproved: Coalbed	Unproved: Tight	Unproved: Low-BTU/ other	Unproved: Total Non-conv	Total undisc	Unproved Plus Discovered Undeveloped	Expected All Time Recovery
United States																	
Lower-48 onshore																	
1	APPAL	Appalachian Basin	8	45.9	9.4	55.3	0.0	2.0	6.2	17.0	8.2	34.7	0.0	59.9	66.1	68.1	123.4
2	WARRIOR	Black Warrior Basin	8	2.6	1.3	3.9	0.0	0.1	1.5	0.0	4.5	0.0	0.0	4.5	5.9	6.0	10.0
3	MAFLA	Mississippi, South Alabama, and Florida	6	9.2	1.9	11.1	0.0	4.4	11.0	0.0	0.0	0.0	0.0	0.0	11.0	15.4	26.5
4	MI-IL	Michigan & Illinois Basins	8	6.4	3.0	9.4	0.0	2.6	7.8	10.4	1.6	0.0	0.0	12.0	19.8	22.5	31.8
5	ARKLATX	East Texas, South Arkansas, & North Louisiana	6	64.5	14.2	78.7	0.0	14.7	18.2	0.0	0.0	5.9	0.0	5.9	24.0	38.7	117.4
6	SoLA	South Louisiana (onshore)	6	102.1	5.2	107.3	0.0	6.5	18.8	0.0	0.0	0.0	0.0	0.0	18.8	25.3	132.6
7	SoTX	South Texas (onshore)	6	145.7	16.2	161.9	0.0	34.6	29.1	0.0	0.0	2.6	0.0	2.6	31.7	66.4	228.2
8	WL	Williston, Northern Great Plains	4	4.5	1.3	5.8	0.0	2.1	3.4	0.0	0.0	7.7	0.0	7.7	11.1	13.1	18.9
9	UINTA-PIC	Uinta-Piceance Basin	4	4.7	7.2	11.9	0.0	3.8	2.1	0.0	5.9	22.8	0.0	28.7	30.8	34.6	46.5
10	POWDER	Powder River Basin	4	2.3	2.4	4.6	0.0	1.0	1.5	0.0	19.4	0.8	0.0	20.2	21.7	22.6	27.3
11	BIGHORN	Big Horn Basin	4	1.9	0.1	2.0	0.0	0.5	0.4	0.0	0.0	0.0	0.0	0.0	0.4	0.9	2.9
12	WINDRVR	Wind River Basin	4	3.2	2.4	5.7	0.0	2.0	1.6	0.0	0.4	0.0	0.0	0.4	2.0	4.0	9.7
13	SoWeWY	Southwestern Wyoming (Green Rvr B)	4	12.8	12.7	25.5	0.0	7.3	4.7	0.0	2.0	65.8	14.5	82.3	87.0	94.3	119.8
14	DEN-P-L	Denver Basin, Park Basins, Las Animas Arch	4	4.2	2.0	6.2	0.0	2.0	1.7	0.0	0.0	2.0	0.0	2.0	3.7	5.7	11.9
15	RATON	Raton Basin-Sierra Grande Uplift	4	0.2	1.2	1.4	0.0	0.0	0.0	0.0	1.9	0.0	0.0	1.9	2.0	2.0	3.3
16	SJB-ASF	San Juan and Albuquerque-Santa Fe Rift	4	29.1	19.6	48.8	0.0	5.4	0.7	0.0	8.4	21.0	0.0	29.4	30.1	35.5	84.3
17	WeMT	Montana Thrust Belt and SW Montana	4	0.2	0.0	0.3	0.0	0.0	8.3	0.0	0.0	0.0	0.0	0.0	8.3	8.3	8.6
18	WY-TB	Wyoming Thrust Belt	4	3.9	0.7	4.6	0.0	1.4	12.0	0.0	0.0	0.0	0.0	0.0	12.0	13.4	18.0
19	PDX-GB	Great Basin and Paradox	3	1.4	1.0	2.4	0.0	1.0	2.7	0.0	0.0	0.0	0.0	0.0	2.7	3.7	6.1
20	OR-WA	Western Oregon-Washington	2	0.1	0.0	0.1	0.0	0.0	1.1	0.0	0.7	11.8	0.0	12.5	13.6	13.6	13.7
21	ANADARKO	Anadarko Basin	7	141.1	17.7	158.8	0.0	21.4	21.0	0.0	0.0	0.0	0.0	0.0	21.0	42.4	201.2
22	ARKOMA	Arkoma-Ardmore	7	25.6	4.8	30.4	0.0	6.8	3.8	0.0	2.6	0.0	0.0	2.6	6.4	13.1	43.5
23	NoMIDCON	Northern Midcontinent	7	13.2	1.5	14.7	0.0	4.1	2.1	0.0	2.3	0.0	0.0	2.3	4.4	8.5	23.1
24	PERMIAN	Permian	5	105.4	16.4	121.8	0.0	21.5	19.6	7.0	0.0	0.0	0.0	7.0	26.6	48.1	169.9
25	NoCAL	Northern California	2	9.2	0.6	9.9	0.0	2.1	3.4	0.0	0.0	0.0	0.0	0.0	3.4	5.6	15.4
26	SoCAL	Central and Southern California	2	22.6	2.0	24.5	0.0	1.1	5.9	0.3	0.0	0.0	0.0	0.3	6.2	7.3	31.8
		total		762.0	144.9	906.9	0.0	148.4	188.5	34.7	57.7	175.1	14.5	282.1	470.6	619.0	1525.9
Lower 48 offshore																	
29	EaGOM-S	Eastern GOM Offshore Shelf	9	3.5	3.4	6.9	0.7	3.4	17.7	0.0	0.0	0.0	0.0	0.0	17.7	21.8	28.8
30	EaGOM-DW-s	Eastern GOM Offshore DW Shallow	9	0.0	0.0	0.0	0.0	0.0	1.9	0.0	0.0	0.0	0.0	0.0	1.9	1.9	1.9
31	EaGOM-DW-d	Eastern GOM Offshore DW Deep	9	0.0	0.0	0.0	0.0	0.0	9.0	0.0	0.0	0.0	0.0	0.0	9.0	9.0	9.0
32	WeGOM-S	Central & Western GOM Offshore Shelf	9	156.7	10.2	166.9	0.0	43.6	86.8	0.0	0.0	0.0	0.0	0.0	86.8	130.5	297.4
33	GOM-DW-PP	C & W GOM Deepwater Plio-Pleistocene	9	2.9	15.5	18.4	0.0	3.4	23.6	0.0	0.0	0.0	0.0	0.0	23.6	27.0	45.5
34	GOM-DW-MIO	C & W GOM Deepwater Miocene	9	0.0	0.0	0.0	0.0	3.0	78.3	0.0	0.0	0.0	0.0	0.0	78.3	81.3	81.3
35	GOM-DW-FB	C & W GOM Deepwater Foldbelts	9	0.0	0.0	0.0	0.0	1.1	27.1	0.0	0.0	0.0	0.0	0.0	27.1	28.1	28.1
36	Pac-Off	Pacific Offshore	11	2.6	0.6	3.2	0.0	1.0	20.7	0.0	0.0	0.0	0.0	0.0	20.7	21.7	24.9
37-39	Atl-Off	Atlantic Offshore	10	0.0	0.0	0.0	0.0	0.0	32.8	0.0	0.0	0.0	0.0	0.0	32.8	32.8	32.8
		total		165.7	29.8	195.5	0.7	55.6	297.9	0.0	0.0	0.0	0.0	0.0	297.9	354.2	549.7
	Eastern GOM			3.5	3.4	6.9	0.7	3.4	28.6	0.0	0.0	0.0	0.0	0.0	28.6	32.7	39.7
	Cental and Western GOM			159.6	25.7	185.3	0.0	51.1	215.8	0.0	0.0	0.0	0.0	0.0	215.8	267.0	452.3
	GOM total			163.1	29.2	192.3	0.7	54.6	244.4	0.0	0.0	0.0	0.0	0.0	244.4	299.7	492.0
Lower 48 onshore total				762.0	144.9	906.9	0.0	148.4	188.5	34.7	57.7	175.1	14.5	282.1	470.6	619.0	1525.9
Lower 48 offshore total				165.7	29.8	195.5	0.7	55.6	297.9	0.0	0.0	0.0	0.0	0.0	297.9	354.2	549.7
Lower 48 total				927.8	174.7	1102.4	0.7	204.0	486.4	34.7	57.7	175.1	14.5	282.1	768.5	973.2	2075.6
40	CeNoAK	North Alaska Onshore:Central	1	3.9	4.9	8.8	8.6	19.4	18.4	0.0	10.6	0.0	0.0	10.6	28.9	56.9	65.7
41	NPRA-AK	North Alaska Onshore: NPRA	1	0.0	0.1	0.1	0.1	0.0	40.7	0.0	31.8	0.0	0.0	31.8	72.4	72.5	72.6
42	ANWR-AK	North Alaska Onshore: ANWR	1	0.0	0.0	0.0	0.0	0.0	13.1	0.0	2.1	0.0	0.0	2.1	15.2	15.2	15.2
43	NoAK-Off	North Alaska Offshore	1	0.4	1.9	2.3	5.3	0.6	96.5	0.0	0.0	0.0	0.0	0.0	96.5	102.3	104.6
44	CeAK	Central Alaska	1	0.0	0.0	0.0	0.0	0.0	2.8	0.0	0.0	0.0	0.0	0.0	2.8	2.8	2.8
45	SoAK-On	South Alaska Onshore	1	3.5	0.9	4.4	0.4	1.1	0.9	0.0	12.5	0.0	0.0	12.5	13.5	15.0	19.4
46	SoAK-Off	South Alaska Offshore	1	3.0	1.0	4.0	0.0	1.0	28.7	0.0	0.0	0.0	0.0	0.0	28.7	29.7	33.7
		total		10.8	8.8	19.6	14.4	22.0	201.0	0.0	57.0	0.0	0.0	57.0	258.0	294.4	314.0
	North Alaska onshore total			3.9	5.0	8.9	8.7	19.4	72.1	0.0	44.5	0.0	0.0	44.5	116.6	144.6	153.6
	North Alaska total			4.3	6.9	11.3	13.9	19.9	168.6	0.0	44.5	0.0	0.0	44.5	213.0	246.9	258.2
	Central Alaska total			0.0	0.0	0.0	0.0	0.0	2.8	0.0	0.0	0.0	0.0	0.0	2.8	2.8	2.8
	South Alaska total			6.5	1.9	8.3	0.4	2.1	29.6	0.0	12.5	0.0	0.0	12.5	42.2	44.7	53.1

Table S2-22. North American Technical Resource Base by 72 Regions – Current Technology (Trillion Cubic Feet)

NATURAL GAS ULTIMATE RECOVERY AND UNDISCOVERED RESOURCES AS OF 1/1/02

(TCF dry; total gas)
(Technically recoverable resource)

Entire resource including no access portion

Region Number	Acronym	Region Name	NPC Super Region	Discovered/proved Cumulative Production	Discovered/proved Proven Reserves	Discovered/proved Ultimate Recovery	Discovered Undeveloped	Unproved Old Field Appreciation	Unproved New Fields	Unproved Shale	Unproved Coalbed	Unproved Tight	Unproved Low-BTU/ other	Unproved Total Non-conv	Unproved Total undisc	Unproved Plus Discovered Undeveloped	Expected All Time Recovery
Alaska onshore total				7.5	5.9	13.3	9.1	20.5	75.8	0.0	57.0	0.0	0.0	57.0	132.8	162.4	175.7
Alaska offshore total				3.4	2.9	6.3	5.3	1.6	125.2	0.0	0.0	0.0	0.0	0.0	125.2	132.0	138.3
Alaska total				10.8	8.8	19.6	14.4	22.0	201.0	0.0	57.0	0.0	0.0	57.0	258.0	294.4	314.0
US onshore total (L48 + AK)				769.5	150.7	920.2	9.1	168.8	264.4	34.7	114.7	175.1	14.5	339.1	603.4	781.4	1701.6
US offshore total (L48 + AK)				169.1	32.7	201.8	6.0	57.2	423.1	0.0	0.0	0.0	0.0	0.0	423.1	486.2	688.0
US total				938.6	183.5	1122.0	15.1	226.0	687.4	34.7	114.7	175.1	14.5	339.1	1026.5	1267.6	2389.6
Canada																	
49	ASM	Alberta, Saskatchewan and Manitoba	12	110.8	48.1	158.9	0.0	24.8	69.9	16.7	25.1	0.0	0.0	41.8	111.7	136.5	295.4
50	BC	British Columbia and Liard Plateau	12	15.2	9.4	24.6	0.0	3.3	22.7	0.0	4.0	0.0	0.0	4.0	26.7	29.9	54.5
51	WeCoastCan	Canada West Coast (prim. offshore)	16	0.0	0.0	0.0	0.0	0.0	10.9	0.0	0.0	0.0	0.0	0.0	10.9	10.9	10.9
52	NWC-On	Northwest Canada Onshore	13	0.1	0.0	0.1	6.3	0.0	12.0	0.0	0.0	0.0	0.0	0.0	12.0	18.4	18.5
53	NWC-Off	Northwest Canada Offshore	13	0.0	0.0	0.0	4.4	0.0	21.8	0.0	0.0	0.0	0.0	0.0	21.8	26.3	26.3
54	EaCanOn	Eastern Canada Onshore	14	1.1	0.4	1.5	0.0	0.2	1.7	0.0	3.9	0.0	0.0	3.9	5.6	5.8	7.3
55-57	EaCanOff	Eastern Canada Offshore	15	0.3	2.2	2.5	15.0	0.4	67.6	0.0	0.0	0.0	0.0	0.0	67.6	83.0	85.5
58	ArcticCan	Arctic Canada	13	0.0	0.0	0.0	13.9	0.0	12.5	0.0	0.0	0.0	0.0	0.0	12.5	26.3	26.3
	WCSB total			126.0	57.5	183.5	0.0	28.1	92.6	16.7	29.1	0.0	0.0	45.8	138.4	166.5	349.9
	NWC total			0.1	0.0	0.1	10.7	0.0	33.9	0.0	0.0	0.0	0.0	0.0	33.9	44.6	44.7
	Eastern Can. Total			1.4	2.6	4.0	15.0	0.6	69.3	0.0	3.9	0.0	0.0	3.9	73.2	88.8	92.8
Canada onshore total		*(Includes Arctic)*		127.2	57.9	185.1	20.2	28.3	118.8	16.7	33.0	0.0	0.0	49.7	168.5	217.0	402.1
Canada offshore total		*(Includes West Coast)*		0.3	2.2	2.5	19.4	0.4	100.3	0.0	0.0	0.0	0.0	0.0	100.3	120.1	122.6
Canada total				127.5	60.1	187.6	39.6	28.7	219.2	16.7	33.0	0.0	0.0	49.7	268.8	337.1	524.7
Mexico																	
59	Sabinas	Sabinas Basin	17	0.3	0.0	0.3	0.0	0.0	3.7	0.0	0.0	0.0	0.0	0.0	3.7	3.7	4.0
60	Burgos-On	Burgos Onshore	17	7.0	2.1	9.1	0.0	3.0	22.8	0.0	0.0	0.0	0.0	0.0	22.8	25.7	34.8
61	Burgos-Shelf	Burgos Shelf	17	0.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	0.0	0.0	2.4	2.4	2.4
62	Burgos-DW	Burgos Deepwater	17	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.6	0.6	0.6
63	Tamp-On	Tampico-Misantla Onshore	17	7.0	13.2	20.2	0.0	12.6	2.5	0.0	0.0	0.0	0.0	0.0	2.5	15.1	35.3
64	Tamp-Shelf	Tampico-Misantla Shelf	17	0.3	0.0	0.3	0.0	0.0	2.5	0.0	0.0	0.0	0.0	0.0	2.5	2.5	2.8
65	Tamp-DW	Tampico-Misantla Deepwater	17	0.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	0.0	0.0	2.4	2.4	2.4
66	Verac-On	Veracruz Onshore	17	1.0	0.3	1.2	0.0	0.7	3.9	0.0	0.0	0.0	0.0	0.0	3.9	4.5	5.8
67	Verc-Shelf	Veracruz Shelf	17	0.0	0.0	0.0	0.0	0.0	3.8	0.0	0.0	0.0	0.0	0.0	3.8	3.8	3.8
68	Verc-DW	Veracruz Deepwater	17	0.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	0.0	0.0	2.4	2.4	2.4
69	Sureste-On	Sureste Onshore	17	23.6	8.4	31.9	0.0	2.6	12.9	0.0	0.0	0.0	0.0	0.0	12.9	15.5	47.5
70	Sureste-Off	Sureste Offshore	17	9.2	4.2	13.5	0.0	3.6	10.6	0.0	0.0	0.0	0.0	0.0	10.6	14.2	27.7
Mexico onshore total				38.9	23.9	62.8	0.0	18.9	45.7	0.0	0.0	0.0	0.0	0.0	45.7	64.5	127.4
Mexico offshore total				9.5	4.3	13.8	0.0	3.6	24.7	0.0	0.0	0.0	0.0	0.0	24.7	28.4	42.1
Mexico total				48.5	28.2	76.6	0.0	22.5	70.4	0.0	0.0	0.0	0.0	0.0	70.4	92.9	169.5
US total				938.6	183.5	1122.0	15.1	226.0	687.4	34.7	114.7	175.1	14.5	339.1	1026.5	1267.6	2389.6
Canada total				127.5	60.1	187.6	39.6	28.7	219.2	16.7	33.0	0.0	0.0	49.7	268.8	337.1	524.7
Mexico total				48.5	28.2	76.6	0.0	22.5	70.4	0.0	0.0	0.0	0.0	0.0	70.4	92.9	169.5
total				1114.5	271.7	1386.2	54.6	277.2	977.0	51.4	147.7	175.1	14.5	388.8	1365.7	1697.5	3083.8
US, Canada, and Mexico onshore				935.6	232.5	1168.1	29.3	216.0	428.8	51.4	147.7	175.1	14.5	388.8	817.6	1062.9	2231.0
US, Canada, and Mexico offshore				178.9	39.2	218.1	25.3	61.2	548.1	0.0	0.0	0.0	0.0	0.0	548.1	634.6	852.7
US, Canada, and Mexico total				1114.5	271.7	1386.2	54.6	277.2	977.0	51.4	147.7	175.1	14.5	388.8	1365.7	1697.5	3083.8

Table S2-22 (Continued)

CHAPTER 3

COST METHODOLOGY

A critical aspect of this study was determining reasonable costs for the model input to determine commercial resources. Costs were required for all aspects of onshore and offshore gas development – exploration and development drilling, production and lease facilities, and operating and maintenance costs. Where possible, public domain data were used to estimate costs. Sources included the API Joint Association Survey on Drilling Costs, the Petroleum Services Association of Canada Well Cost Studies, and the EIA's Oil & Gas Lease Equipment and Operating Costs. In areas where adequate public domain data was not available, costs were based on available information and circulated to industry experts familiar with costs in that area for review and comment. Costs were revised based on the input received. At each of the regional workshops, held primarily to review the resources, costs were also discussed in order to determine key factors affecting costs in that region (i.e., infrastructure, weather, drilling depths, etc.).

It is important to note that the costs used in the model are average costs for generic operations. For example, the well costs are for generic wells at an average drill depth. Actual costs will vary depending upon specific locations with regards to water depth, drill depth, pore pressure, rig type, etc. The same is true for the development costs. Actual costs will depend on location, infrastructure, metocean conditions, well productivity, etc.

This chapter contains sections that discuss the cost data used in the study by region (Gulf of Mexico, Lower-48 Onshore, Alaska, Atlantic, Pacific, Western Canada, Other Canada, and Mexico) as well as sections on nonconventional gas costs and rig fleet availability. Each section presents summary data. Additional cost data can be found on the CD-ROM that the NPC is making available as part of the study documentation.

I. Gulf of Mexico

The Gulf of Mexico was divided into super-plays and subdivided by water depth intervals. Well depths were based on the resource weighted average reservoir depth for a given super-play and water depth. Costs were developed for both shallow and deep water scenarios. For the shallow water scenarios, two water depths were assumed (100' and 400'), and costs were developed for both exploration wells and platform development wells. For the deepwater scenarios, four water depths were assumed (1000', 2000', 4000', and 6000'), and costs were developed for exploration wells and both subsea completed and platform completed development wells. Platform and subsea completed wells were assumed to be deviated wells which resulted in a greater drill depth than for exploration wells. Table S3-1 shows the average reservoir depth, referenced to sea level, by super-play and water depth.

The initial drilling and completion (D&C) costs were provided by the Minerals Management Service (MMS). These costs were sent to industry experts for review and were adjusted based on the comments received. Tables S3-2 and S3-3 show the estimated costs, days for the operation and drill depth by water depth and super-plays for exploration (E), subsea completed (SS), and platform (PF) wells. The boldface depth is the average reservoir depth for the exploration well. As stated above, the platform and subsea wells

Water Depth	Pleistocene/ Pliocene	Miocene	Texas Deep Shelf	Foldbelt (Perdido)	Foldbelt (Miss. Fan)	EGOM (Norphlet)	EGOM (shallow)	EGOM (deep)
0-40m (100’)	8,830’	11,650’	25,000’			21,910’	13,325’	18,250’
40-200m (400’)	8,830’	11,650’	25,000’			21,910	13,325’	18,250’
200-400m (1000’)	11,215’	14,305’				21,910’	13,325’	18,250’
400-800m (2000’)	11,215’	14,305’			16,970’		13,325’	18,250’
800-1,600m (4000’)	11,215’	14,305’/ 20,000’		11,070’	16,970’		13,325’	18,250’
> 1,600m (6000’)	11,215’	14,305’/ 20,000’		11,070’	16,970’		13,325’	

Table S3-1. Average Reservoir Depth by Super-Play and Water Depth

Water Depth	EGOM (Norphlet)	EGOM (Shallow)	EGOM (Deep)
	E / SS / PF	E / SS / PF	E / SS / PF
0-40m (100’)	**21,910** / - / 24,000	**13,325** / - / 15,000	**18,250** / - / 20,000
Cost ($MM)	28.0 / - / 27.0	7.0 / - / 8.0	15.0 / - / 15.0
Days	180 / - / 175	60 / - / 70	105 / - / 110
40-200m (400’)	**21,910** / - / 24,000	**13,325** / - / 15,000	**18,250** / - / 20,000
Cost ($MM)	30.0 / - / 27.0	8.0 / - / 8.0	19.0 / - / 15.0
Days	180 / - / 175	60 / - / 70	105 / - / 110
200-400m (1,000’)	**21,910** / - / 24,000	**13,325** / 14,700 / 16,700	**18,250** / 20,000 / 22,800
Cost ($MM)	33.0 / - / 30.0	13.5 / 20.0 / 9.0	21.5 / 30.0 / 14.0
Days	170 / - / 165	60 / 80 / 75	90 / 110 / 115
400-800m (2,000’)		**13,325** / 14,700 / 16,700	**18,250** / 20,000 / 22,800
Cost ($MM)		13.5 / 20.0 / 9.0	21.5 / 30.0 / 14.0
Days		60 / 80 / 75	90 / 110 / 115
800-1,600m (4,000’)		**13,325** / 14,700 / 16,700	**18,250** / 20,000 / 22,800
Cost ($MM)		19.0 / 28.5 / 17.0	30.0 / 41.5 / 25.0
Days		60 / 75 / 70	85 / 110 / 110
> 1,600m (6,000’)		**13,325** / 14,700 / 16,700	
Cost ($MM)		21.0 / 30.5 / 20.0	
Days		50 / 70 / 70	

Note: E = exploration; SS = subsea; and PF = platform.

Table S3-2. D&C Costs for Eastern Gulf of Mexico

Water Depth	Pleistocene/ Pliocene	Miocene	Texas Deep Shelf	Foldbelt (Perdido)	Foldbelt (Miss. Fan)
	E / SS / PF	**E / SS / PF**	**E / SS / PF**	**E / SS / PF**	**E / SS / PF**
0-40m (100')	**8,830** / - / 10,300	**11,650** / - / 13,300	**25,000** / - / 27,500		
Cost ($MM)	4.0 / - / 5.0	6.0 / - / 7.0	55.0 / - / 65.0		
Days	40 / - / 45	55 / - / 60	250 / - / 235		
40-200m (400')	**8,830** / - / 10,300	**11,650** / - / 13,300	**25,000** / - / 27,500		
Cost ($MM)	5.0 / - / 5.0	7.0 / - / 7.0	55.0 / - / 65.0		
Days	40 / - / 45	55 / - / 60	250 / - / 235		
200-400m (1,000')	**11,215** / 12,300 / 14,000	**14,305** /15,700 / 17,900			
Cost ($MM)	10.0 / 17.0 / 7.0	14.0 / 21.0 / 9.5			
Days	45 / 65 / 60	65 / 85 / 80			
400-800m (2,000')	**11,215** / 12,300 / 14,000	**14,305** /15,700 / 17,900			**16,970** / 18,700 / 21,250
Cost ($MM)	10.0 / 17.0 / 7.0	14.0 / 21.0 / 9.5			20.0 / 28.0 / 13.0
Days	45 / 65 / 60	65 / 85 / 80			85 / 105 / 105
800-1,600m (4,000')	**11,215** / 12,300 / 14,000	**14,305** /15,700 / 17,900		**11,070** /12,100 / 13,750	**16,970** / 18,700 / 21,250
Cost ($MM)	14.0 / 24.0 / 14.0	20.0 / 30.0 / 18.0		14.0 / 24.0 / 14.0	28.0 / 38.0 / 23.0
Days	40 / 60 / 55	60 / 80 / 75		40 / 60 / 55	80 / 100 / 100
		20,000 / 22,000 / 25,000			
Cost ($MM)		40.0 / 56.0 / 34.0			
Days		105 / 130 / 135			
> 1,600m (6,000')	**11,215** / 12,300 / 14,000	**14,305** / 15,700 / 17,900		**11,070** / 12,100 / 13,750	**16,970** / 18,700 / 21,250
Cost ($MM)	15.0 / 27.0 / 17.0	22.0 / 32.0 / 21.0		15.0 / 27.0 / 17.0	32.0 / 44.0 / 27.0
Days	35 / 55 / 55	55 / 70 / 75		35 / 55 / 55	75 / 95 / 100
		20,000 / 22,000 / 25,000			
Cost ($MM)		45.0 / 63.0 / 39.0			
Days		95 / 120 / 125			

Note: E = exploration; SS = subsea; and PF = platform.

Table S3-3. D&C Costs for Central/Western Gulf of Mexico have a greater drill depth due to deviation requirements. Costs are in year 2000 dollars.

Offshore development costs were developed for both shallow and deepwater scenarios as stated above. A substantial part of offshore development costs are not associated with the drilling costs. Non-drilling development costs include production platforms, production equipment, subsea equipment, abandonment costs, and gathering pipelines. The development plan/concept for any particular field is a function of field size, water depth, location, and well productivity. The development concepts considered in this study for the Gulf of Mexico are: a steel pile jacket (SPJ), which is a bottom founded fabricated steel structure; a tension leg platform (TLP), which is a seabed anchored buoyant/compliant substructure constructed in steel or concrete; a spar, a buoyant concrete caisson which is anchored to the seabed; and subsea (SS) production systems/tiebacks. Noted in Table S3-4 are the development concepts assumed for the different water depths and super-plays.

The initial non-drilling development costs were based on EEA's spreadsheets and were benchmarked and adjusted based on the database in the Wood Mackenzie U.S. GOM Deepwater Study (November 2001). These costs were sent to industry experts for review and were adjusted based on the comments received. Note that these costs are averages based on typical parameters for offshore developments. Costs are in year 2000 dollars. Figure S3-1 illustrates the cost curves for a development in the 800 – 1600m water depths for the different super-plays.

Gulf of Mexico operating costs were based on the above-mentioned deepwater study. These costs were sent to industry experts for review and were adjusted based on the comments received. Note that these operating costs are also averages of typical offshore developments and are presented in year 2000 dollars. Figure S3-2 illustrates an operating cost curve based on reservoir size for a development in 800 to 1600m water depths.

II. Lower-48 Onshore

D&C costs for the lower-48 onshore wells were based on the American Petroleum Institute's (API) Joint Association Survey (JAS) on Drilling Costs. This survey has been conducted annually since 1959 and is sent to operators who have conducted drilling operations during the year. The survey provides total D&C costs for oil, gas, and dry wells on a state and regional basis by depth intervals. All cost components such as permitting, location construction, mobilization, rentals and services, tangible items, and stimulations are assumed to be included. The API JAS also contains a breakdown of D&C costs for coal bed methane, horizontal, and sidetrack wells.

For this NPC study, the 1999 and 2000 surveys were used to determine an average base case cost for oil, gas, and dry wells in 26 regions. The regions were

Water Depth	Pleisto-cene/ Pliocene	Miocene	Texas Deep Shelf	Foldbelt (Perdido)	Foldbelt (Miss. Fan)	EGOM (Norphlet)	EGOM (shallow)	EGOM (deep)
0-40m (100')	SPJ	SPJ	SPJ			SPJ	SPJ	SPJ
40-200m (400')	SPJ	SPJ	SPJ			SPJ	SPJ	SPJ
200-400m (1,000')	SPJ/SS	SPJ/SS				SPJ/SS	SPJ/SS	SPJ/SS
400-800m (2,000')	TLP/SS	TLP/SS			TLP/SS		TLP/SS	TLP/SS
800-1,600m (4,000')	Spar/SS	Spar/SS		Spar/SS	Spar/SS		Spar/SS	Spar/SS
> 1,600m (6,000')	Spar/SS	Spar/SS		Spar/SS	Spar/SS		Spar/SS	

Note: SPJ = steel pile jacket; TLP = tension leg platform; and SS = subsea.

Table S3-4. Gulf of Mexico Development Concepts

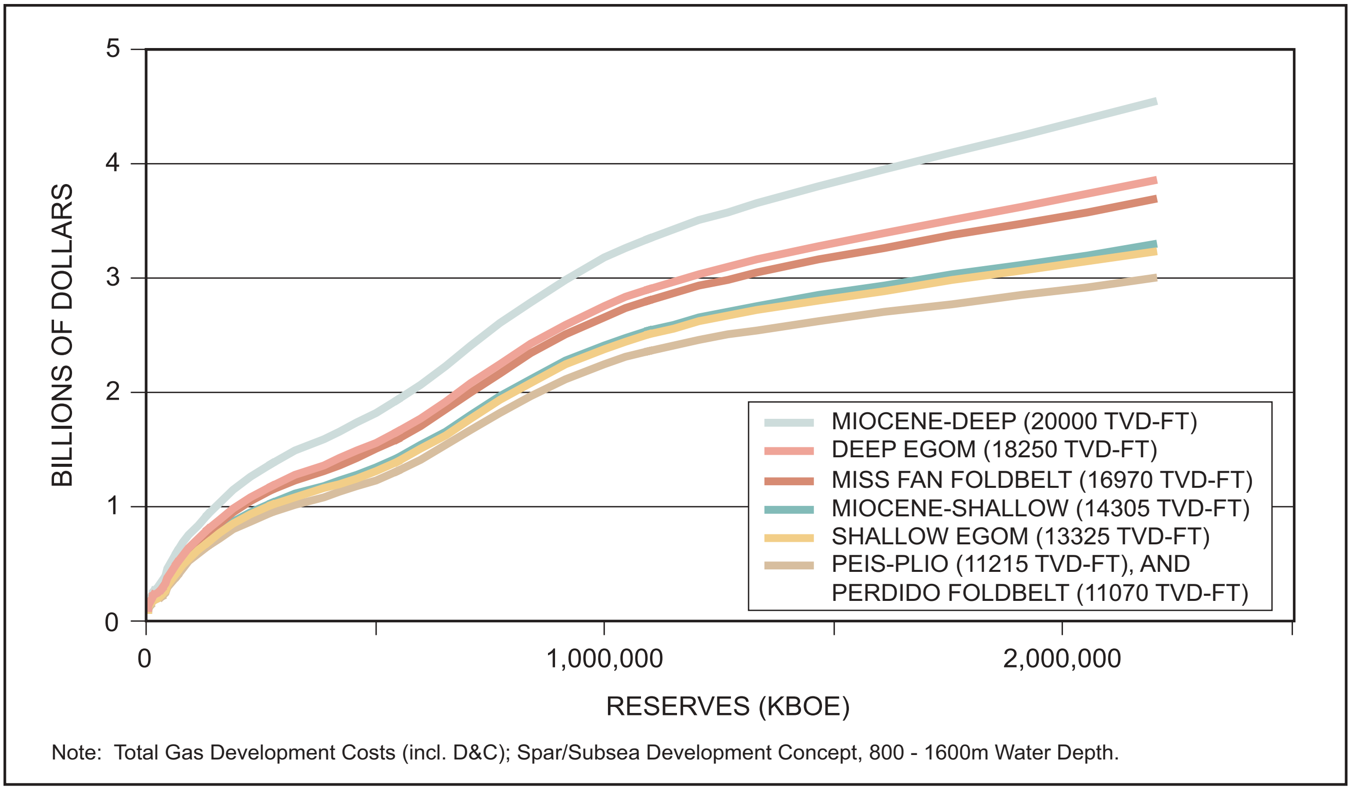


Figure S3-1. Example of Gulf of Mexico Development Cost Curves

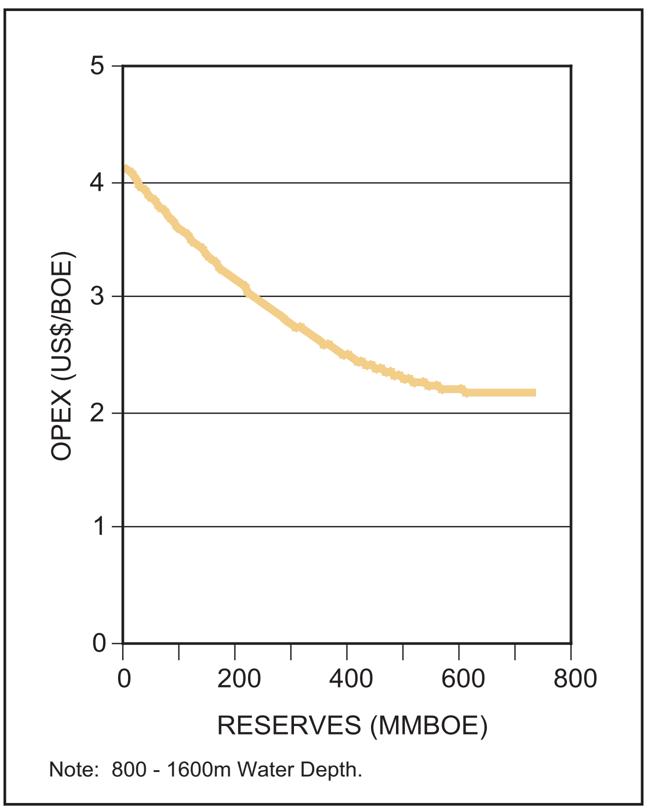


Figure S3-2. Example of Gulf of Mexico Operating Cost Curve

divided into four depth intervals at 5000' increments. Tables S3-5, S3-6, and S3-7 summarize the costs used in the model.

Onshore development costs, also known as lease equipment costs, consist of everything needed to produce a well past the wellhead tree (i.e., flowline and connections, separators, dehydrators, pumps, and storage tanks). Onshore development costs were derived from EIA's Report "Oil and Gas Lease Equipment and Operating Costs 1986 Through 2000." This report, which has accompanying Excel spreadsheets, presents estimated costs of all equipment and services that are in effect during June of each year. The aggregate costs for typical leases by region, depth, and production rate are averaged, and these averages provide a general measure of the changed costs from year to year for lease equipment and operations. Costs for the model input are in year 2000 dollars. The report is public domain information and can be viewed on EIA's web site. Tables S3-8 and S3-9 illustrate the equipping and operating costs for gas wells by depth, region, and producing rate. These tables only contain the costs for the 250 MCF/D producing rate; however, more information can be obtained for different producing rates in the EIA report.

Region	Drilling Depth Intervals			
	0-5,000’	5,000’-10,000’	10,000’-15,000’	15,000’-20,000’
	$K/Well	$K/Well	$K/Well	$K/Well
Appalachian Basin	90	176	1,297	3,746
Black Warrior Basin	196	385	1,097	2,701
Mississippi, S. Alabama, Florida	214	385	1,097	2,701
Michigan & Illinois Basin	97	794	1,223	3,746
E. Texas, S. Arkansas, N. Louisiana	132	472	1,640	3,746
South Louisiana (onshore)	488	1,494	2,532	5,765
South Texas (onshore)	179	652	1,643	3,607
Williston, Northern Great Plains	280	955	1,311	3,122
Uinta-Piceance Basin	281	444	2,002	3,366
Powder River Basin	159	710	1,238	3,334
Big Horn Basin	273	513	1,314	3,553
Wind River Basin	224	495	1,170	3,553
Southwestern Wyoming (Green River B)	219	446	1,530	3,469
Denver Basin, Park Basins, Las Animas Arch	231	485	1,704	3,553
Raton Basin-Sierra Grande Uplift	211	523	1,475	3,553
San Juan & Albuquerque-Santa Fe Uplift	201	458	1,475	3,553
Montana Thrust Belt & SW Montana	241	433	1,475	3,553
Wyoming Thrust Belt	211	523	2,102	3,553
Great Basin & Paradox	184	541	1,716	3,553
Western Oregon-Washington	139	1,149	3,019	12,766
Anadarko Basin	128	456	1,384	2,870
Arkoma-Ardmore	131	456	1,374	2,870
Northern Midcontinent	131	393	637	2,870
Permian Basin	182	416	788	2,866
Northern California	139	1,149	3,019	12,766
Central & Southern California	139	1,149	3,019	12,766

Table S3-5. Lower-48 Onshore Oil Well D&C Costs

Region	Drilling Depth Intervals			
	0-5,000’	5,000’-10,000’	10,000’-15,000’	15,000’-20,000’
	$K/Well	$K/Well	$K/Well	$K/Well
Appalachian Basin	150	226	1,180	4,626
Black Warrior Basin	220	286	963	3,501
Mississippi, S. Alabama, Florida	264	274	833	2,914
Michigan & Illinois Basin	127	660	1,612	4,626
E. Texas, S. Arkansas, N. Louisiana	122	692	1,239	4,090
South Louisiana (onshore)	698	1,502	2,827	7,110
South Texas (onshore)	172	675	1,939	4,545
Williston, Northern Great Plains	83	571	2,445	3,519
Uinta-Piceance Basin	216	570	1,574	4,407
Powder River Basin	83	1,061	1,871	5,412
Big Horn Basin	249	578	1,390	5,412
Wind River Basin	250	796	1,902	8,244
Southwestern Wyoming (Green River B)	197	849	1,613	4,470
Denver Basin, Park Basins, Las Animas Arch	166	665	1,697	5,412
Raton Basin-Sierra Grande Uplift	155	469	1,697	5,412
San Juan & Albuquerque-Santa Fe Uplift	185	548	1,697	5,412
Montana Thrust Belt & SW Montana	206	669	1,697	5,412
Wyoming Thrust Belt	85	562	2,415	4,007
Great Basin & Paradox	222	712	1,697	5,412
Western Oregon-Washington	75	489	1,180	5,726
Anadarko Basin	143	500	1,307	2,991
Arkoma-Ardmore	143	500	1,307	2,991
Northern Midcontinent	143	500	1,307	2,991
Permian Basin	180	510	1,345	4,464
Northern California	281	488	1,180	5,726
Central & Southern California	384	499	1,169	5,726

Table S3-6. Lower-48 Onshore Gas Well D&C Costs

Region	Drilling Depth Intervals			
	0-5,000’	5,000’-10,000’	10,000’-15,000’	15,000’-20,000’
	$K/Well	$K/Well	$K/Well	$K/Well
Appalachian Basin	75	174	1,368	4,217
Black Warrior Basin	227	261	885	6,344
Mississippi, S. Alabama, Florida	216	323	831	4,300
Michigan & Illinois Basin	78	411	1,618	4,217
E. Texas, S. Arkansas, N. Louisiana	82	357	1,016	3,900
South Louisiana (onshore)	383	967	2,249	4,509
South Texas (onshore)	101	447	1,656	4,102
Williston, Northern Great Plains	100	506	1,204	2,442
Uinta-Piceance Basin	113	295	739	2,506
Powder River Basin	159	378	1,035	2,444
Big Horn Basin	145	338	1,196	3,392
Wind River Basin	136	317	1,010	6,770
Southwestern Wyoming (Green River B)	157	366	1,183	2,553
Denver Basin, Park Basins, Las Animas Arch	162	279	953	2,506
Raton Basin-Sierra Grande Uplift	97	231	1,108	2,506
San Juan & Albuquerque-Santa Fe Uplift	110	311	1,781	2,506
Montana Thrust Belt & SW Montana	149	253	1,108	2,506
Wyoming Thrust Belt	106	332	1,321	2,643
Great Basin & Paradox	138	288	821	2,468
Western Oregon-Washington	111	742	1,275	5,736
Anadarko Basin	97	249	860	2,036
Arkoma-Ardmore	100	249	860	2,036
Northern Midcontinent	190	267	860	2,036
Permian	102	309	943	8,437
Northern California	305	712	1,144	5,736
Central & Southern California	227	807	1,536	5,736

Table S3-7. Lower-48 Onshore Dry Hole Well Costs

Region	Producing Depth (feet)			
	2,000	4,000	8,000	12,000
Midcontinent	23,300	30,600	47,900	64,300
North Louisiana	21,500	31,300	48,100	
Rocky Mountains	23,200	47,500	51,400	65,500
South Louisiana	21,500	31,800	49,100	
South Texas	20,600	30,900	47,600	
West Texas	18,000	28,300	45,100	60,400
Lower-48 States	21,400	33,400	48,200	63,400
Source: EIA's report "Oil & Gas Lease Equipment and Operating Costs 1986 through 2000."				

Table S3-8. Equipping Costs per Well for Onshore Gas Leases in Year 2000 (250 MCF/D Rate)

Region	Producing Depth (feet)			
	2,000	4,000	8,000	12,000
Midcontinent	14,300	19,200	30,200	37,200
North Louisiana	13,200	18,200	31,300	
Rocky Mountains	14,800	24,700	32,900	40,500
South Louisiana	13,200	18,200	31,100	
South Texas	12,500	16,900	28,900	
West Texas	12,200	17,000	29,000	36,200
Lower-48 States	13,400	19,000	30,600	38,000
Source: EIA's report "Oil & Gas Lease Equipment and Operating Costs 1986 through 2000."				

Table S3-9. Operating Costs per Well for Onshore Gas Leases in Year 2000 (250 MCF/D Rate)

III. Alaska – Onshore and Offshore

Cost parameters (water depth and reservoir depth) were provided on an area basis. D&C costs for onshore regions were initially based on limited data contained in the API JAS. These costs were sent to industry experts and adjusted based on additional industry experience. D&C costs for offshore regions were initially based on previous EEA generated costs. These costs were also sent to industry experts and adjusted based on additional industry input. Table S3-10 summarizes the estimated costs in year 2000 dollars which are for a generic type well. Actual costs will vary depending upon specific locations with regard to water depth, drill depth, pore pressure, rig type, etc.

Onshore development costs consist of the same components as onshore U.S. lower-48 estimates with additional costs added for access road and utility construction due to remote locations of the new fields. Onshore development and operating costs, expressed on a per well basis, are based on EEA generated costs that were reviewed and adjusted by industry experts. The final onshore development and operating costs in year 2000 dollars are summarized in Table S3-11.

Offshore development costs consist of the same components as U.S. GOM estimates. The development concepts considered in this study for offshore Alaska are: an offshore platform, usually a steel pile jacket; a

Region	Water Depth (m)	Average Depth (feet)	Development D&C Cost ($MM/well)	Exploration Drilling Cost ($MM/well)
Onshore Foldbelt Shallow	onshore	4,000	3.0	18.0
Onshore Foldbelt Deep	onshore	12,700	7.0	20.0
Onshore Coastal Plain Shallow	onshore	7,250	3.0	15.0
Onshore Coastal Plain Deep	onshore	25,000	18.0	40.0
Nearshore Beaufort Sea	30	7,350	12.0	40.0
Offshore Beaufort Shallow Water	50	6,200	12.0	40.0
Offshore Beaufort Deeper Water	150	6,800	18.0	45.0
Chukchi Sea Foldbelt	50	6,200	15.0	50.0
Chukchi Sea Other	50	8,600	16.0	50.0
Bering Sea	100	12,000	17.0	45.0
Central Alaska Onshore	onshore	6,500	3.0	10.0
Onshore Cook Inlet	onshore	6,500	2.5	8.0
Offshore Cook Inlet	50	11,000	10.0	22.0
Gulf of Alaska	100	15,000	15.0	35.0

Table S3-10. Alaska Onshore and Offshore D&C Costs

Region	Equipment Costs ($K)		O&M Costs ($K)	
	Oil	Gas	Oil	Gas
Onshore Foldbelt Shallow	9,723	5,871	1,761	1,585
Onshore Foldbelt Deep	9,723	5,871	1,761	1,585
Onshore Coastal Plain Shallow	9,723	5,871	1,761	1,585
Onshore Coastal Plain Deep	9,723	5,871	1,761	1,585
Central Alaska onshore	9,723	5,871	1,761	1,585
Onshore Cook Inlet	372	137	250	250

Table S3-11. Alaska Onshore Equipment Costs and Annual Operating & Maintenance Costs

Region	Water Depth (m)	Development Type
Nearshore Beaufort Sea	30	Gravel Island w/ subsea wells
Offshore Beaufort Shallow Water	50	All subsea w/ pipeline to shore
Offshore Beaufort Deeper Water	150	All subsea w/ pipeline to shore
Chukchi Sea Foldbelt	50	All subsea w/ pipeline to shore
Chukchi Sea Other	50	All subsea w/ pipeline to shore
Bering Sea	100	Gravity Based Structure (GBS)
Offshore Cook Inlet	50	Platform
Gulf of Alaska	100	Gravity Based Structure (GBS)

Table S3-12. Alaska Offshore Development Concepts gravel island; a gravity based structure (GBS), a platform constructed in concrete which sits on the seabed; and subsea production systems/tiebacks. Noted in Table S3-12 are the development concepts assumed for the different water depths and areas.

Initial development costs were based on EEA generated costs benchmarked and adjusted based on Wood Mackenzie database. These costs were sent to industry experts for review and were adjusted based on the comments received. Note that these costs are averages based on typical parameters for offshore developments in this region. Costs are based on year 2000 dollars. Figure S3-3 illustrates the cost curve for the Nearshore Beaufort Sea. Graphs were produced for each play/area estimated.

Offshore operating costs, expressed on a per well basis, are based on EEA generated costs that were reviewed and adjusted by industry experts. The final operating costs in year 2000 dollars are summarized in Table S3-13.

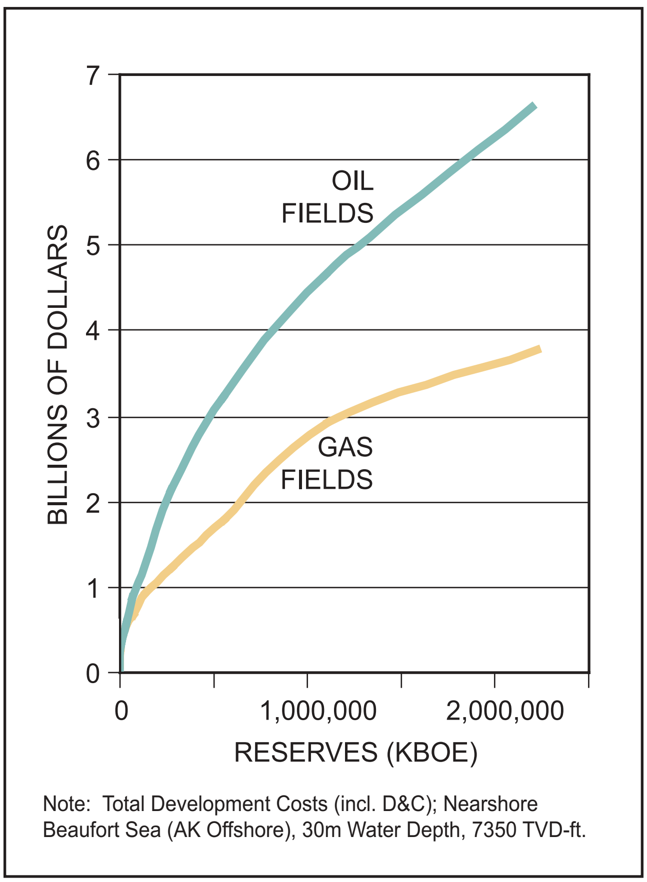


Figure S3-3. Example of Alaska Offshore Development Cost Curves

Region	O&M Costs ($K)	
	Oil	Gas
Nearshore Beaufort Sea	1,761	1,585
Offshore Beaufort Shallow Water	1,761	1,585
Offshore Beaufort Deeper Water	1,761	1,585
Chukchi Sea Foldbelt	1,761	1,585
Chukchi Sea Other	1,761	1,585
Bering Sea	1,761	1,585
Offshore Cook Inlet	624	624
Gulf of Alaska	1,761	1,585

Table S3-13. Alaska Offshore Annual Operating & Maintenance Costs

IV. Atlantic Offshore

Cost parameters (water depth and reservoir depth) were provided on an area basis. Due to lack of recent drilling activity in the Atlantic Offshore region, D&C costs were based on GOM well costs for similar water depths and reservoir depths. Adjustment factors based on industry experience were used to account for the differences in infrastructure, logistics, weather, drilling conditions, etc. The following adjustment factors were used for D&C costs:

- Subsea Development – 1.5
- Platform Development – 1.4
- Exploration – 1.75

Table S3-14 summarizes the estimated costs in year 2000 dollars which are for a generic type well. Actual costs will vary depending upon specific locations with regards to water depth, drill depth, pore pressure, rig type, etc.

Development costs and operating costs for the Atlantic Offshore regions are based on GOM costs for similar water depths. Due to lack of development in the region, adjustment factors based on industry experience were used to account for the differences in infrastructure, logistics, weather, etc. Table S3-15 shows the non-D&C adjustment factors used for the different regions and the analagous GOM regions.

Region	Water Depth (m)	Average Depth (feet)	Development D&C Cost ($MM/well)		Exploration Drilling Cost ($MM/well)
			SS	PF	
Atlantic Shelf – Shallow	100	9,250	NA	7.0	9.0
Atlantic Shelf – Deep	100	15,750	NA	17.0	26.0
Atlantic Slope – Shallow	500	9,250	23.0	7.0	14.0
Atlantic Slope – Deep	500	15,750	39.0	17.0	32.0
Atlantic Deepwater – Shallow	1,000	11,250	36.0	20.0	25.0
Atlantic Deepwater – Deep	1,000	17,750	57.0	32.0	49.0

Note: SS = subsea; and PF = platform.

Table S3-14. Atlantic Offshore D&C Costs

Region	Water Depth (m)	Gulf of Mexico Region	Factor	Development Type
Atlantic Shelf – Shallow	100	40-200m Pleis-Plio	1.4	SPJ
Atlantic Shelf – Deep	100	40-200m Pleis-Plio	1.6	SPJ
Atlantic Slope – Shallow	500	400-800m Pleis-Plio	1.4	TLP / SS
Atlantic Slope – Deep	500	400-800m Pleis-Plio	1.6	TLP / SS
Atlantic Deepwater – Shallow	1,000	800-1600m Pleis-Plio	1.4	Spar / SS
Atlantic Deepwater – Deep	1,000	800-1600m Pleis-Plio	1.6	Spar / SS

Note: SPJ = steel pile jacket; TLP = tension leg platform; and SS = subsea.

Table S3-15. Atlantic Offshore Adjustment Factors

V. Pacific Offshore

Cost parameters (water depth and reservoir depth) were provided on an area basis. Due to minimal drilling activity in the Pacific Offshore region, D&C costs were based on GOM well costs for similar water depths and reservoir depths. Adjustment factors based on industry experience were used to account for the differences in infrastructure, logistics, weather, drilling conditions, etc. The following adjustment factors were used for D&C costs:

- Subsea Development – 1.5
- Platform Development – 1.1 - 1.4
- Exploration – 2.0

Table S3-16 summarizes the estimated costs in year 2000 dollars which are for a generic type well. Actual costs will vary depending upon specific locations with regards to water depth, drill depth, pore pressure, rig type, etc.

Development costs and operating costs for the Pacific Offshore regions are based on GOM costs for similar water depths. Due to lack of recent development in the region, adjustment factors based on industry experience were used to account for the differences in infrastructure, logistics, weather, etc. Table S3-17 shows the non-D&C adjustment factors used for the different regions and the analagous GOM regions.

Region	Water Depth (m)	Average Depth (feet)	Development D&C Cost ($MM/well)		Exploration Drilling Cost ($MM/well)
			SS	PF	
Oregon-Washington Shelf	100	8,000	NA	6.0	9.0
Central California Shelf	100	10,000	NA	7.0	11.0
Central California Slope	400	10,000	24.0	8.0	18.0
Southern California Shelf	200	10,500	NA	7.0	12.0
Southern California Slope	400	11,000	25.0	9.0	20.0
Southern California Deepwater	1,300	11,100	36.0	18.0	28.0
Note: SS = subsea; and PF = platform.					

Table S3-16. Pacific Offshore D&C Costs

Region	Water Depth (m)	Gulf of Mexico Region	Factor	Development Type
Oregon-Washington Shelf	100	40-200m Pleis-Plio	1.2	SPJ
Central California Shelf	100	40-200m Pleis-Plio	1.2	SPJ
Central California Slope	400	200-400m Pleis-Plio	1.4	SPJ / SS
Southern California Shelf	200	40-200m Pleis-Plio	1.2	SPJ
Southern California Slope	400	200-400m Pleis-Plio	1.4	SPJ / SS
Southern California Deepwater	1,300	800-1,600m Pleis-Plio	1.5	Spar / SS
Note: SPJ = steel pile jacket; TLP = tension leg platform; and SS = subsea.				

Table S3-17. Pacific Offshore Adjustment Factors

VI. Western Canada Onshore

D&C costs were based on the Petroleum Services Association of Canada (PSAC) well cost study. The PSAC is the national association of Canadian oilfield service, supply, and manufacturing companies and develops two well cost studies, summer and winter drilling seasons, per year. These studies contain D&C costs in a detailed Authority for Expenditure (AFE) format for typical or most popular wells being drilled. The studies generally include 30-35 wells. Table S3-18 summarizes the estimated costs by region for generic type wells. The regions are divided by geographical areas and well drill depth intervals. The costs shown are averages based on the Summer 2002 and Winter 2003 studies and have been adjusted to 2000 dollars (U.S.). Actual costs will vary depending upon specific locations with regard to location, drill depth, pore pressure, etc.

Onshore development costs consist of the same components as the U.S. lower-48 onshore estimates with additional costs added for access road and utility construction due to remote locations of the new fields. Onshore development and operating costs, expressed on a per well basis, are based on EEA generated costs that were reviewed and adjusted by industry experts. The final onshore development (equipment) and operating (O&M) costs in year 2000 dollars are summarized in Table S3-19.

Region	Oil		Gas		Dry	
	Average Depth (feet)	US $K	Average Depth (feet)	US $K	Average Depth (feet)	US $K
Alberta Plains (0-5,000’)	2,600	185	2,200	162	1,800	102
Alberta Plains (5,000-10,000’)	7,000	561	7,300	611	6,800	401
Alberta Plains (> 10,000’)	10,800	1,450	11,500	1,700	12,000	1,419
Alberta Foothills (0-10,000’)	7,300	908	7,300	907	6,600	590
Alberta Foothills (> 10,000’)	12,800	2,817	13,300	3,080	12,400	1,946
Southeast Alberta (0-5,000’)	3,800	186	2,500	131	3,400	125
Southeast Alberta (> 5,000’)	6,300	354	7,400	482	6,800	305
Williston (Saskatchewan & Manitoba)	4,000	273	2,000	147	3,300	169
British Columbia Plains (0-5,000’)	4,300	445	3,600	376	3,800	299
British Columbia Plains (5,000-10,000’)	6,800	785	7,200	845	6,600	565
British Columbia Plains (> 10,000’)	10,300	1,659	11,600	2,175	11,100	1,455
British Columbia Foothills (0-10,000’)	7,000	854	5,900	674	6,000	509
British Columbia Foothills (> 10,000’)	11,800	2,307	12,500	2,642	12,400	1,939
Liard Plateau	7,500	5,231	7,500	5,231	7,500	3,923

Table S3-18. Western Canada Onshore D&C Costs

Region	Equipment Costs (US $K)		O&M Costs (US $K)	
	Oil	Gas	Oil	Gas
Alberta Plains (0-5,000’)	237	200	45	22
Alberta Plains (5,000-10,000’)	312	212	51	25
Alberta Plains (> 10,000’)	375	225	84	84
Alberta Foothills (0-10,000’)	518	362	84	84
Alberta Foothills (> 10,000’)	518	362	84	84
Southeast Alberta (0-5,000’)	237	200	45	22
Southeast Alberta (> 5,000’)	312	212	51	25
Williston (Saskatchewan & Manitoba)	237	200	45	22
British Columbia Plains (0-5,000’)	443	350	51	25
British Columbia Plains (5,000-10,000’)	518	362	57	29
British Columbia Plains (> 10,000’)	574	375	94	94
British Columbia Foothills (0-10,000’)	518	362	94	94
British Columbia Foothills (> 10,000’)	518	362	94	94
Liard Plateau	788	262	57	57

Table S3-19. Western Canada Onshore O&G Field Equipment Costs and Annual Operating & Maintenance Costs

VII. Canada Offshore and Onshore Other

Cost parameters (water depth and reservoir depth) were provided on an area basis. D&C costs were initially based on preliminary work (December 2002) by the Canadian Energy Research Institute (CERI) and previous EEA generated costs. These costs were sent to industry experts for review and were adjusted based on the comments received from the experts. Table S3-20 summarizes the estimated costs in year 2000 U.S. dollars which are for a generic type well. Actual costs will vary depending upon specific locations with regards to water depth, drill depth, pore pressure, rig type, etc.

Onshore development costs consist of the same components as the U.S. lower-48 onshore estimates with additional costs added as required for access road and utility construction due to remote locations of the new fields. Onshore development and operating costs, expressed on a per well basis, are based on EEA generated costs that were reviewed and adjusted by industry experts. The final onshore development (equipment) and operating (O&M) costs in year 2000 dollars are summarized in Table S3-21.

Offshore development costs consist of the same components as U.S. GOM estimates. Different development concepts were selected based on the water depth and region as noted in Table S3-22.

Initial development costs were based on EEA generated costs, preliminary work by CERI, and the Wood Mackenzie database. These costs were sent to industry experts for review and were adjusted based on the comments received. Note that these costs are averages based on typical parameters for offshore developments in this region. Costs are based on year 2000 dollars. Figure S3-4 illustrates the cost curve for the Jeanne d'Arc area. Graphs were produced for each play/area estimated.

Offshore operating costs, expressed on a per well basis, are based on EEA generated costs that were reviewed and adjusted by industry experts. The final operating costs in year 2000 dollars are summarized in Table S3-23.

Region	Water Depth (m)	Average Depth (feet)	Development D&C Cost ($MM/well)	Exploration Drilling Cost ($MM/well)
Eastern Canada Onshore	onshore	15,000	15.0	20.0
Eastern Canada – Maritimes	< 200	15,000	35.0	40.0
Eastern Canada – Labrador	< 200	11,500	65.0	75.0
Eastern Canada – Orphan	> 2,000	14,500	60.0	70.0
Eastern Canada – Jeanne d'Arc	< 200	14,500	40.0	50.0
Eastern Canada – Scotian Slope	1,800	16,000	55.0	60.0
Eastern Canada – Sable Sub-basin	< 200	15,000	35.0	40.0
Eastern Canada – Scotian Shelf Deep	< 200	20,000	60.0	65.0
Pacific – West Coast Basins	30-2,000	12,500	30.0	45.0
Mackenzie Beaufort – Shallow	< 20	11,000	20.0	45.0
Mackenzie Beaufort – Deep	> 20	11,000	20.0	45.0
Mackenzie Delta	onshore	11,000	18.0	35.0
Mackenzie Corridor	onshore	7,000	10.0	25.0
Arctic Islands	0-500	7,000	50.0	70.0

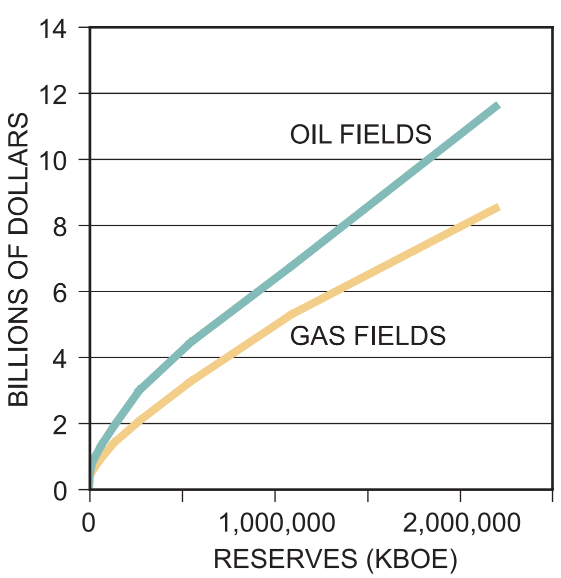
Table S3-20. Canada Offshore and Onshore Other D&C Costs

Region	Equipment Costs (US $K)		O&M Costs (US $K)	
	Oil	Gas	Oil	Gas
Eastern Canada	97	36	15	15
Mackenzie Delta/Corridor	25,388	19,570	1,761	1,761

Table S3-21. Canada Onshore Other O&G Field Equipment Costs and Annual Operating & Maintenance Costs

Region	Water Depth (m)	Development Type
Eastern Canada – Maritimes	< 200	Gravity Based Structure (GBS)
Eastern Canada – Labrador	< 200	Gravity Based Structure (GBS)
Eastern Canada – Orphan	> 2,000	All Subsea with Pipeline to Shore
Eastern Canada – Jeanne d'Arc	< 200	Gravity Based Structure (GBS)
Eastern Canada – Scotian Slope	1,800	All Subsea with Pipeline to Shore
Eastern Canada – Sable Subbasin	< 200	Gravity Based Structure (GBS)
Eastern Canada – Scotian Shelf Deep	< 200	Gravity Based Structure (GBS)
Pacific – West Coast Basins	30-2,000	GBS w/ Subsea Dev. at Deeper Depths
Mackenzie Beaufort – Shallow	< 20	Gravel Island
Mackenzie Beaufort – Deep	> 20	All Subsea with Pipeline to Shore
Arctic Islands	0-500	All Subsea with Pipeline to Shore

Table S3-22. Offshore Canada Development Concepts



Note: Total Development Cost Benchmark (incl. D&C); Jeanne d'Arc – Eastern Canada, <200m Water Depth; 14,500 TVD-ft.

Figure S3-4. Example of Offshore Canada Development Cost Curves

Region	Operating Costs (US $K)
Eastern Canada – Maritimes	1,761
Eastern Canada – Labrador	1,761
Eastern Canada – Orphan	1,761
Eastern Canada – Jeanne d'Arc	1,761
Eastern Canada – Scotian Slope	500
Eastern Canada – Sable Subbasin	500
Eastern Canada – Scotian Shelf Deep	500
Pacific – West Coast Basins	1,761
Mackenzie Beaufort – Shallow	1,761
Mackenzie Beaufort – Deep	1,761
Arctic Islands	1,761

Table S3-23. Offshore Canada O&G Well Annual Operating & Maintenance Costs

VIII. Mexico

Cost parameters (water depth and reservoir depth) were provided on an area basis. D&C costs for onshore areas were based on data from Pemex's website for multiple services contracts for Burgos Basin. The costs for the Burgos Basin were extrapolated to other areas based on average depth. Offshore D&C costs were based on GOM well costs for similar water depths and reservoir depths. An adjustment factor of 1.5 was used to account for the differences in infrastructure, logistics, drilling conditions, etc. Table S3-24 summarizes the estimated costs in year 2000 dollars which are for a generic type well. Actual costs will vary depending upon specific locations with regards to water depth, drill depth, pore pressure, rig type, etc.

Development costs for Mexico came from the IHS Mexico Study. For onshore developments, the development plan is comprised of wellsites tied back to a dedicated production facility incorporating separation, condensate stabilization, gas dew-pointing, gas export, compression and condensate export. Gas and condensate are exported to main gas and oil export pipelines which send oil and gas to a processing plant. Tables S3-25 and S3-26 show the development and operating costs in year 2000 dollars per well for onshore gas wells.

There were two development concepts utilized in the IHS study for offshore developments. For small fields and shallow water, a lightweight steel jacket supporting wellheads was used. The well fluids are tied back in a multiphase flowline to existing production facilities. Wells are drilled and maintained using a jack-up drilling rig. For larger fields and in deepwater, the development plan consists of steel jackets supporting wellheads, production, quarters, and compression. The production facilities incorporate separation, condensate stabilization, gas dew-pointing, gas export, compression, and condensate export. Gas is exported

Region	Water Depth (m)	Average Depth (m)	Development D&C Cost ($MM/well)	Exploration Drilling Cost ($MM/well)
Sabinas	onshore	3,100	2.6	2.4
Burgos Onshore	onshore	2,200	1.6	1.5
Burgos Onshore	onshore	2,800	2.3	2.1
Burgos Shelf	100	3,500	10.5	10.5
Burgos Deepwater	2,500	5,500	SS: 75.0; PF: 46.0	54.0
Tampico-Misantla Onshore	onshore	2,200	1.6	1.5
Tampico-Misantla Shelf	100	3,200	9.0	9.0
Tampico-Misantla Deepwater	1,500	3,800	SS: 40.0; PF: 24.0	25.5
Veracruz Onshore	onshore	2,600	2.2	2.1
Veracruz Shelf	100	3,200	9.0	9.0
Veracruz Shelf	100	5,000	19.5	22.5
Veracruz Deepwater	1,500	4,500	SS: 48.0; PF: 30.0	33.0
Sureste Onshore	onshore	3,000	2.3	2.2
Sureste Onshore	onshore	4,900	7.4	7.0
Sureste Offshore	100	3,800	11.0	12.0

Note: SS = subsea; and PF = platform.

Table S3-24. Mexico D&C Costs

Region	Reserves per Field				
	20 BCF	50 BCF	100 BCF	500 BCF	1,000 BCF
Sabinas	3.1	0.6	16.0	50.9	100.7
Burgos	3.1	4.8	14.4	48.1	80.1
Sureste	3.1	3.9	23.2	28.3	71.5
Tampico-Misantla	5.0	5.8	10.5	24.8	48.6
Veracruz	5.0	5.8	10.5	24.8	48.6

Table S3-25. Mexico Onshore Gas Field Development Costs (U.S. Million Dollars per Field)

Region	Reserves per Field				
	20 BCF	50 BCF	100 BCF	500 BCF	1,000 BCF
Sabinas	0.6	0.6	11.3	11.3	63.3
Burgos	0.6	1.1	128.	41.4	84.6
Sureste	0.3	0.8	10.0	24.5	61.8
Tampico-Misantla	1.4	1.6	11.7	40.8	71.2
Veracruz	1.4	1.6	11.7	40.8	71.2

Table S3-26. Mexico Onshore Gas Field Operating & Maintenance Costs (U.S. Million Dollars over Life of Field)

to an onshore gas processing plant and condensate is exported to an onshore terminal. Costs are based on year 2000 dollars. Figures S3-5 and S3-6 illustrate the Development and Operating cost curves for Burgos Deepwater Offshore area. Graphs were produced for each play/area estimated.

IX. Nonconventional Gas

Costs for nonconventional gas developments (coal bed methane and tight gas) were handled in each geographical area using essentially the same cost methodology as for conventional developments. For coal bed methane developments, adjustments required for the unique production style (i.e., dewatering of the coal prior to onset of gas production) were made. Dehydration and storage tank costs were removed from the lease equipment cost component, and costs for water handling equipment and compression were added. In addition, capex and O&M costs for water disposal, dependent upon the type of disposal (i.e., surface discharge or re-injection), were included. Costs for stimulation of tight gas zones were accounted for in the D&C costs.

X. Rig Fleet Availability

An important consideration in the development of future resources is the availability of equipment, particularly drilling rigs, to do the work. Most of the rigs currently available for use today were built in the late 1970s and early 1980s. Since this time period, in which the number of active rigs peaked, both the onshore and offshore rig fleets have declined. One yearly survey that tracks the number of available rigs is the Reed-Hycalog Rig Census. Conducted since the 1950s, this survey tracks the number of rigs available by surveying drilling contractors. Rigs are considered available if they have worked during a 45-day qualification period. Rigs not considered available include those requiring a capital expenditure (excluding drillpipe) of $100,000 for a land rig and $1,000,000 for an offshore rig and those rigs stacked for more than 3 years. Also not considered are rigs that cannot drill below 3000'.

Figure S3-7 shows the Reed-Hycalog Census results for the past 15 years. In 1987, the total number of rigs available, both land and offshore, was 3,331 (peak was in 1982 with 5,644 available rigs). In 2001, the total available was 1,722.

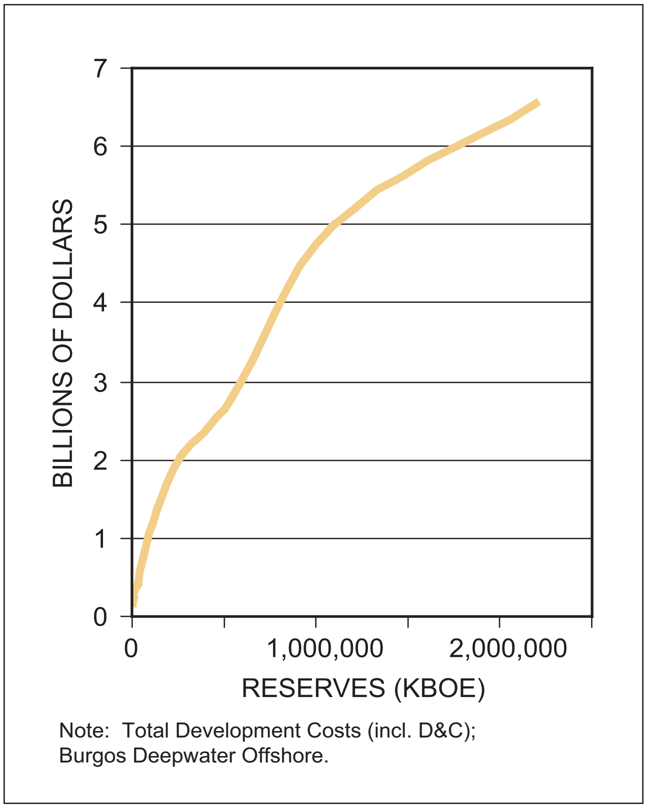


Figure S3-5. Example of Offshore Mexico Development Cost Curves

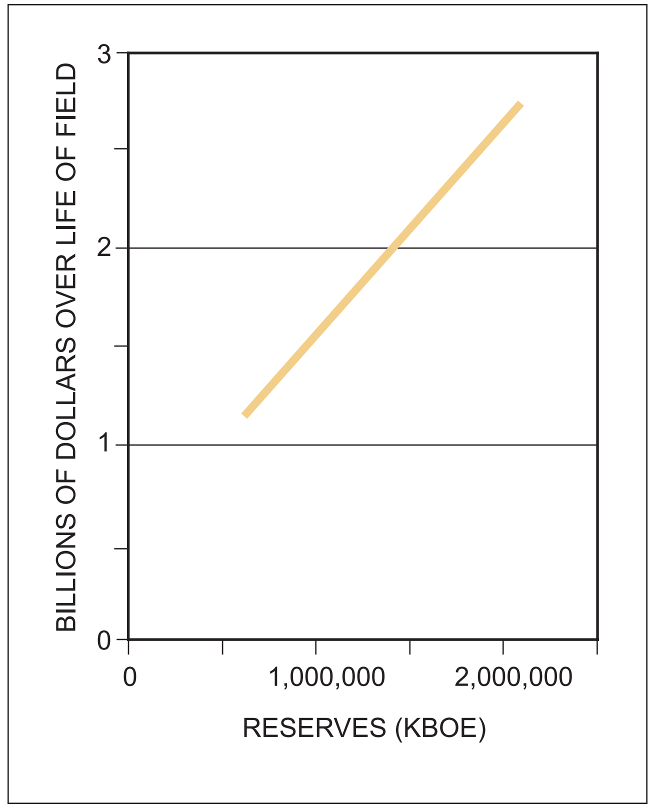


Figure S3-6. Example of Offshore Mexico Deepwater Operating Cost Curves

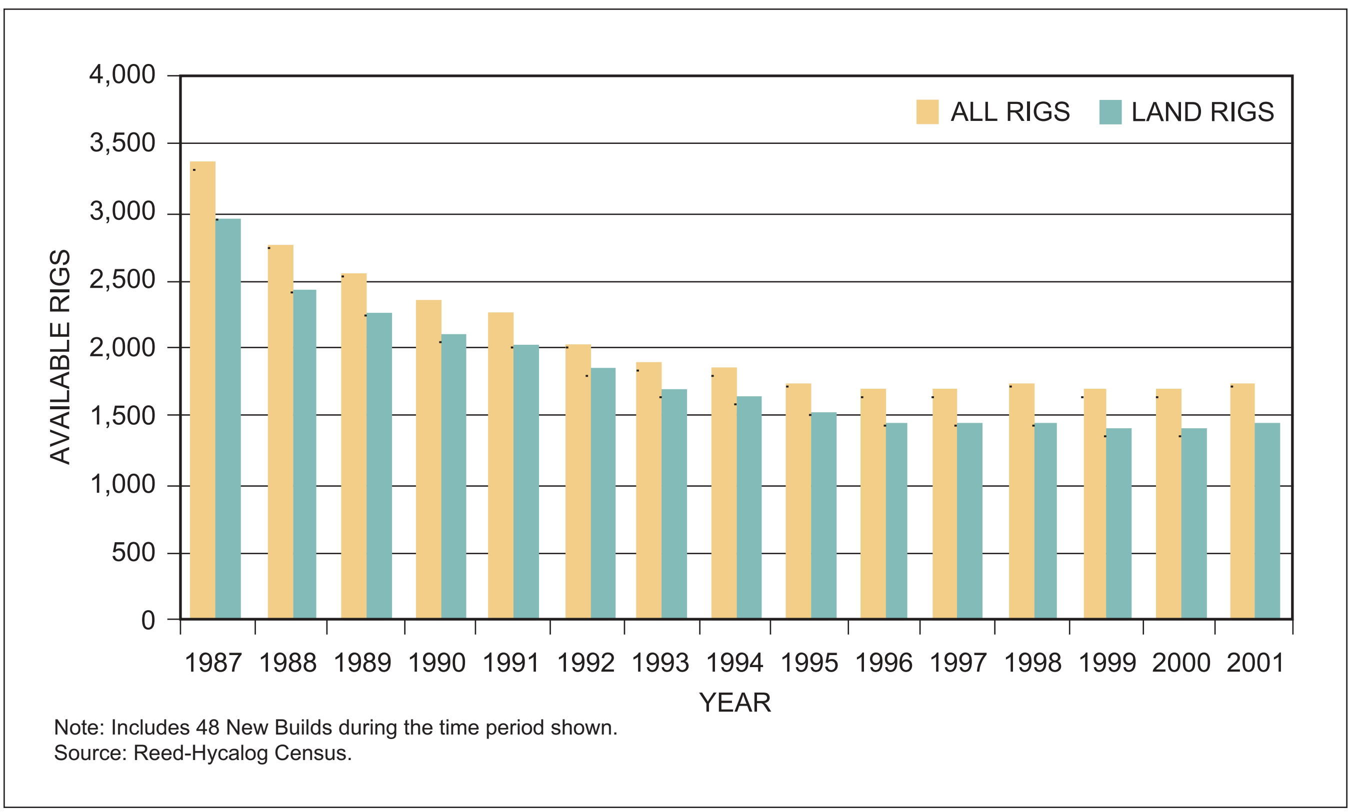


Figure S3-7. Rig Fleet Availability

Figures S3-8 and S3-9 show both the reductions and additions to the rig fleet for the same 15-year time period. It is interesting to note that the majority of rigs added to the fleet in recent years are rigs brought back into service and rigs assembled from components rather than newly manufactured rigs. This indicates the difficulty with attempting to predict how many rigs are truly available now and in the future. Typically, during high activity periods, more rigs will be brought back into service, perhaps even more than industry would project. However, during slow activity periods, these rigs will again be stacked and will eventually be removed from the available category even though they will likely come back if another high activity period occurs.

This cyclic nature makes it difficult to predict how many of the current rigs will be available in the future and how many newly manufactured rigs will be required. The key in predicting the future impact is determining what the real attrition rates will be, that is, how many rigs will be completely removed from the fleet and never be able to return to work. For the purpose of this study, discussions were held with major drilling contractors to attempt to predict future attrition rates. Different rig fleet attrition scenarios were discussed and a consensus was reached on a particular scenario for both the onshore and offshore rig fleets. Figures S3-10 and S3-11 project the estimated rig fleet availability out to 2025.

For the onshore fleet, a period of slight growth and stabilization was assumed out to 2005. For the next 20 years the following attrition rates to the existing rig fleet were assumed:

2006-2010 – 1%

2011-2015 – 1.5%

2016-2020 – 2%

2021-2025 – 3%.

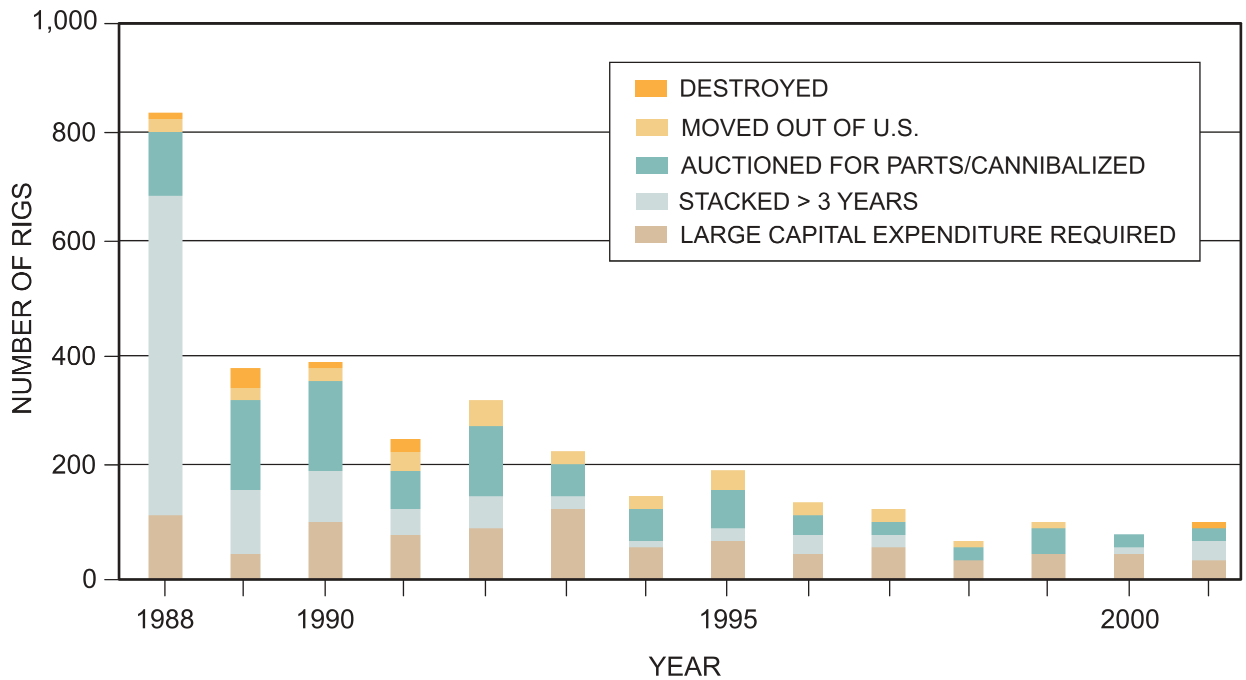
For the offshore fleet, a period of slight growth and stabilization was also assumed out to 2005. For the next 20 years the following attrition rates to the existing rig fleet were assumed:

2006-2010 – 2%

2011-2015 – 2.5%

2016-2020 – 3%

2021-2025 – 3.5%.



Source: Reed-Hycalog Census.

Figure S3-8. Reductions to Rig Fleet

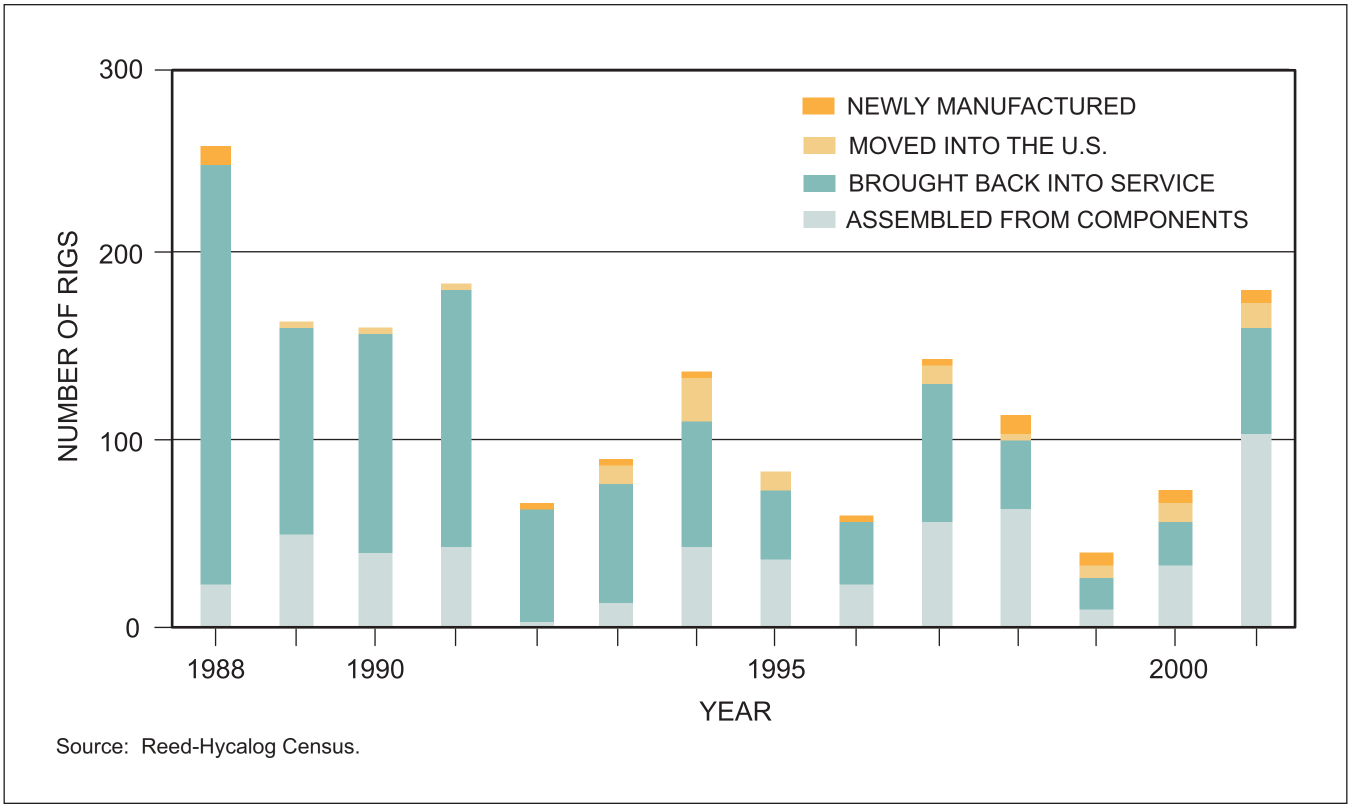


Figure S3-9. Additions to Rig Fleet

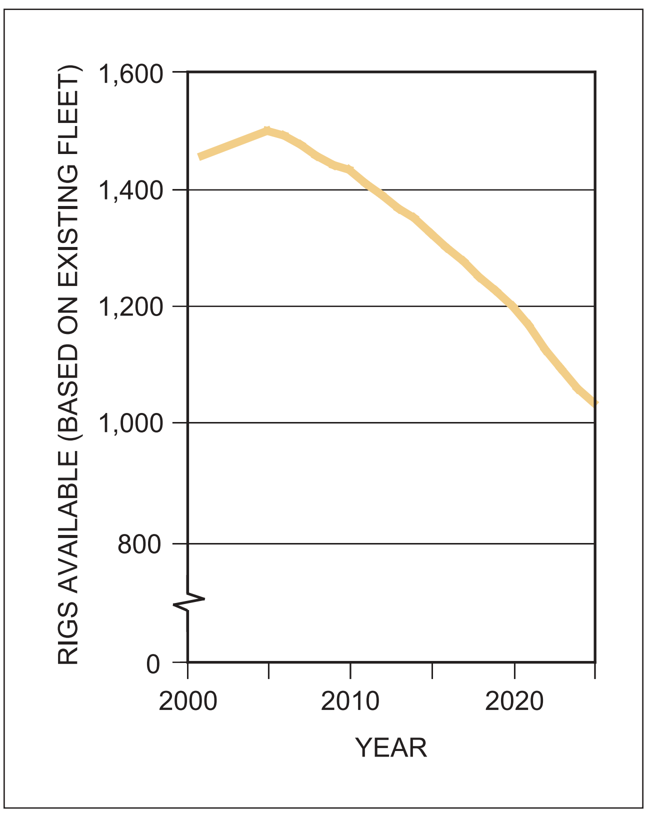


Figure S3-10. Projected Onshore Rig Fleet Attrition

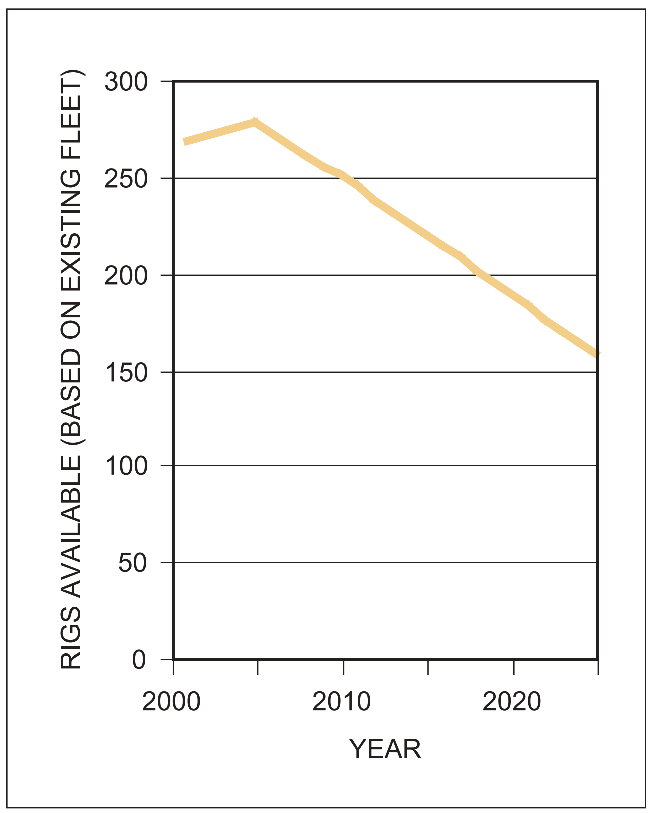


Figure S3-11. Projected Offshore Rig Fleet Attrition

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CHAPTER 4

PRODUCTION PERFORMANCE

I. Production Performance Analysis

In order to help estimate future well performance parameters and to calibrate the Hydrocarbon Supply Model (HSM) results, an analysis of historical production performance was undertaken for the U.S. lower-48 and Western Canada. Analyses were conducted for the period from 1990 to the present, in order to put current trends into a long-term context. The analysis then focused on the last four years of production performance with the aim of understanding the reasons behind the lack of significant production response following the large ramp-up of industry activity in 2000 and 2001.

Production performance was analyzed using four parameters to describe key trends and to understand the causes of those trends. The four parameters were:

- Gas Well Drilling Activity vs. Production
- Individual Gas Well Performance
  - Estimated Ultimate Recovery
  - Initial Production Rate
  - Initial Decline Rate
- Base Decline of Existing Reserves
- Reserves and R/P ratios.

Production performance parameters were summarized on a regional basis, although most areas were analyzed on a much more granular basis looking at individual formation response, response by depth tranche, and response by resource type (i.e., coal bed methane vs. conventional performance). The majority of the data for the analysis emanated originally from the IHS Production Database. To standardize the vast amount of data and perform standard analyses, the IHS production data was conditioned by EEA to ensure completeness, accuracy, and standardization.

The production performance parameters generated in the analysis were used either as direct inputs to the HSM, or to check HSM outputs.

A. Key Findings

1. While North American production has grown 11 BCF/D (1.8% p.a.) between 1990 and present, growth has slowed dramatically post 1996 even as drilling activity levels have dramatically increased. Excess deliverability has gradually eroded, average well productivity has declined, and declines have steepened in the maturing resource base.

2. Gas production has been essentially flat in the U.S. lower-48 since 1996. Growth in the Rocky Mountains, Deepwater Gulf of Mexico (GOM), and more recently East Texas/North Louisiana has been offset by production losses in the other regions, particularly the Gulf of Mexico Shelf and Midcontinent. Canadian production growth, which comprised 65% of the total growth since 1990, slowed dramatically and began to decline, even as the number of Canadian gas well completions has more than tripled.

3. "Conventional" gas production in the U.S. lower-48 has been on decline since 1990 and "nonconventional" production has doubled from 12% to 25% of production. Aside from the Deepwater Gulf of Mexico, the only U.S. basins maintaining sustainable

production increases (East Texas/North Louisiana, Rocky Mountains) are largely being driven by increases in nonconventional production.

4. Average Estimated Ultimate Recovery (EUR), excluding Appalachia and the Deepwater GOM, fell 15% between 1990 and 1999 as the resource base matured, the industry focused on development opportunities, and technology gains and higher prices made smaller prospects economic. As drilling ramped up in response to the 2000-01 price spike, average EUR fell a further 18%, as more marginal wells were drilled.

5. Lower-48 Onshore average EUR fell marginally in the 1990s as the industry successfully employed new technologies and targeted some of the less mature areas. In contrast, in the GOM Shelf, average EUR fell dramatically between 1990 and 1999. The still depressed GOM rig count is a strong indication that results continued to worsen post-1999. Drilling is slowly shifting to the Deep Shelf, which may help flatten production losses. Western Canadian average EUR has fallen dramatically as the basin rapidly matured and the industry concentrated on low-risk, shallow drilling.

6. Initial Production Rates (IPs) increased markedly through the early to mid-1990s, helping the industry to maintain production, as the industry employed technology to accelerate production and improve drilling economics. Increases in IPs have flattened in the later part of the 1990s as per well reserves fell and fracture technology implementation neared saturation level in most basins. Declining EURs and increasing IPs have resulted in steepening initial well decline rates.

7. As more and more high decline wells have been added to base production, base decline rates have risen dramatically. Just to maintain production levels requires production from first year wells of 12-13 BCF/D, up from 8 BCF/D in 1992. Western Canada has shown a similar increase in base decline.

8. Industry has replaced over 100% of U.S. lower-48 production since 1990. The 2000-01 reserve adds were larger than average; however, essentially 100% of the incremental reserve adds were in Non-Producing Reserves, which now comprise 28% of the total. Western Canadian Proved Reserves have fallen steadily over the last 13 years and R/P has fallen from 18 to 9.

9. Industry responded aggressively to the 2000-01 price spike, with the gas rig count climbing to over 1,050. The incremental activity yielded a limited production response as the (1) resource base continued to mature, (2) additional drilling yielded very low marginal results, (3) much of the incremental activity occurred in low rate regions, (4) gains from completion/stimulation technology slowed, (5) base decline rates continued to increase, (6) higher gas prices made it possible to drill lower quality prospects, and (7) rig efficiency suffered.

10. Improved data reporting would increase confidence of estimates of recent performance trends. Timely reporting is especially critical in the GOM, a high impact area, with high declines on the Shelf and rapid development in the Deepwater. Performance prediction in other areas (e.g., Appalachia) is also hampered by poor data reporting.

B. Summary

Production of natural gas in the U.S. lower-48 and Canada has increased 11 BCF/D (0.9 BCF/D p.a.) from an average of 57.8 BCF/D in 1990 to 68.9 BCF/D in 2002, an increase of 19% (1.8% p.a.). Peak production rates have increased somewhat less, as excess summertime gas deliverability present in the early 1990s has been increasingly utilized to satisfy increasing summer power demand and to fill incremental gas storage.

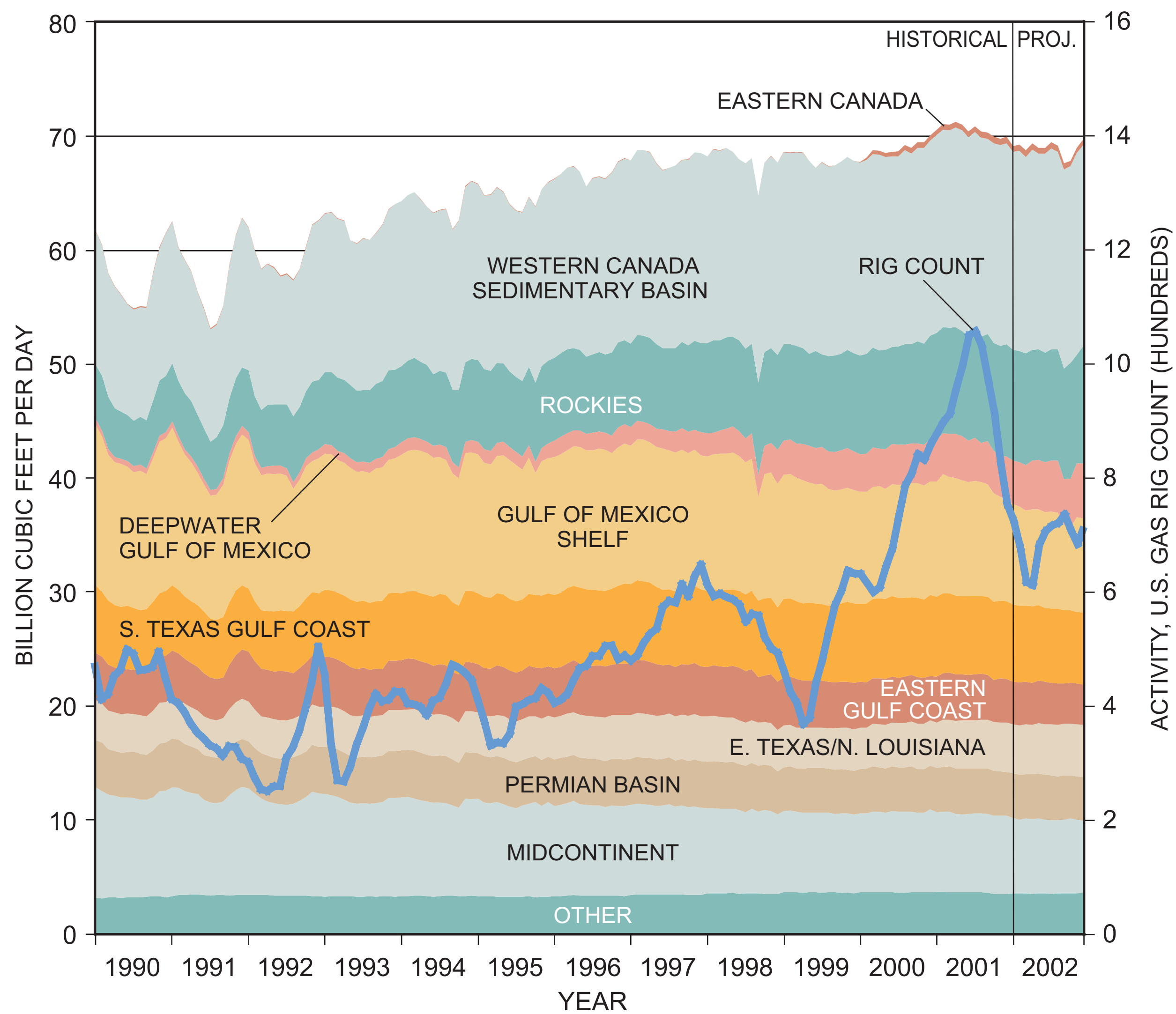
Within North America, production gains were largely concentrated in three regions, the Western Canada Sedimentary Basin, the Rocky Mountains, and the Deepwater Gulf of Mexico, as advances in technology and infrastructure allowed the industry to exploit these less mature areas. These three areas alone now account for approximately 45% of total gas production, up from 27% in 1990.

Production growth in North America has slowed, from 2.3% p.a. in the early 1990s, to 0.6% p.a. over the period 1996-2002, even as activity has dramatically increased. Production gains from Western Canada, the Rocky Mountains, and the Deepwater GOM have been offset by steepening declines from the more mature GOM Shelf and onshore lower-48 basins. These declines were temporarily flattened during a big drilling ramp-up in 2000 and 2001, but resumed as drilling levels fell back to 600-700 U.S. gas rigs in late 2001 and 2002. Activity levels which had generated increased production in the mid-1990s, were insufficient to even hold production steady. Canadian production, which accounted for approximately 65% of the growth since 1990, has flattened and begun to decline, even with significantly higher activity levels. (See Figure S4-1 and Table S4-1.)

The character of the production and the resource base has become increasingly "nonconventional." "Conventional" gas production in the U.S. lower-48 has actually fallen throughout the 1990s. Nonconventional production – namely coal bed methane, shale gas, and tight gas – grew from 12% of production in 1990 to approximately 25% currently. (See Figure S4-2.)

As the resource base has matured, the industry has been on average, exploiting progressively smaller accumulations of gas. In the U.S. lower-48, average EUR per gas connection has fallen from 1.4 BCF in 1990 to under 1 BCF by 2001. In Western Canada, average EURs have fallen even more dramatically, from 1.6 BCF to 0.3 BCF/connection by 2001. (See Figure S4-3.)

At the same time it has been exploiting increasingly smaller accumulations of gas, the industry has successfully employed technology to accelerate production and improve drilling economics. Initial Production Rates increased markedly through the early- to



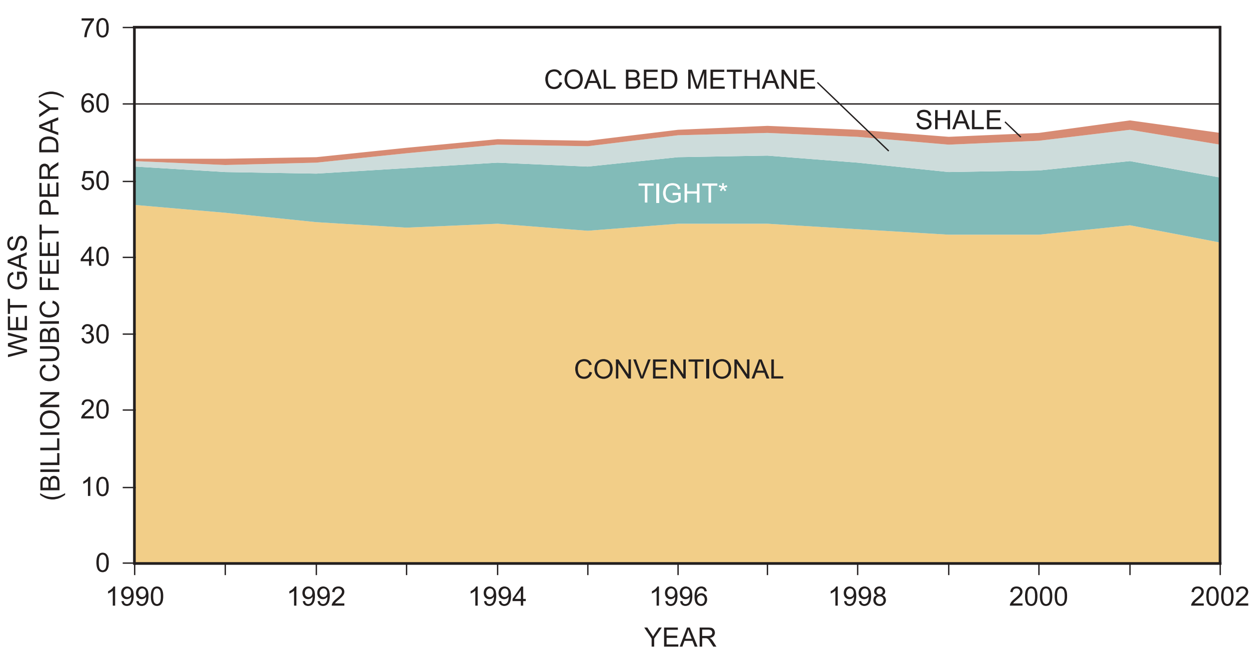
Sources: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR); Baker Hughes.

Figure S4-1. U.S. Lower-48 and Canadian Production by Region

	Average Growth Rate (% p.a.)			Volumes (BCF/D)				
	1990-1996	1996-1999	1999-2002	1990	1996	1999	2001	2002
Total U.S. Lower-48 + Canada	**2.3**	**0.5**	**0.6**	**57.8**	**66.6**	**67.7**	**70.3**	**68.9**
Canada	**6.0**	**2.4**	**2.2**	**10.8**	**15.7**	**16.8**	**18.0**	**18.0**
U.S. Lower-48	**1.3**	**-0.1**	**0.1**	**47.0**	**50.9**	**50.8**	**52.2**	**50.9**
Total Frontier Areas	**8.9**	**9.3**	**6.3**	**5.0**	**8.7**	**11.7**	**13.1**	**14.2**
Rocky Mountains	7.7	5.2	4.9	4.4	7.2	8.4	9.4	9.8
GOM Deepwater	16.6	22.2	9.7	0.5	1.5	3.2	3.7	4.4
Total Mature Areas	**0.1**	**-2.3**	**-2.4**	**42.0**	**42.2**	**39.4**	**39.1**	**36.7**
GOM Shelf	-0.7	-5.3	-7.5	12.8	12.2	10.5	9.8	8.4
Texas Gulf Coast	2.9	0.9	-1.5	5.6	6.7	6.8	6.9	6.5
Eastern Gulf Coast	0.7	-3.4	-3.5	4.0	4.1	3.8	3.7	3.4
East Texas/North Louisiana	1.6	0.6	4.9	3.4	3.8	3.8	4.2	4.5
Midcontinent	-2.0	-4.4	-2.5	9.0	8.0	7.0	6.9	6.5
Permian Basin	0.0	-1.7	0.0	4.1	4.1	3.9	4.0	3.9
Other	0.7	2.7	-0.8	3.2	3.3	3.6	3.6	3.5

Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Table S4-1. North American Annual Dry Gas Production



* Tight gas estimated 2000-2002.

Sources: GTI Gas Resource Database; Energy and Environmental Analysis, Inc.

Figure S4-2. U.S. Lower-48 Wet Gas Production by Resource Type

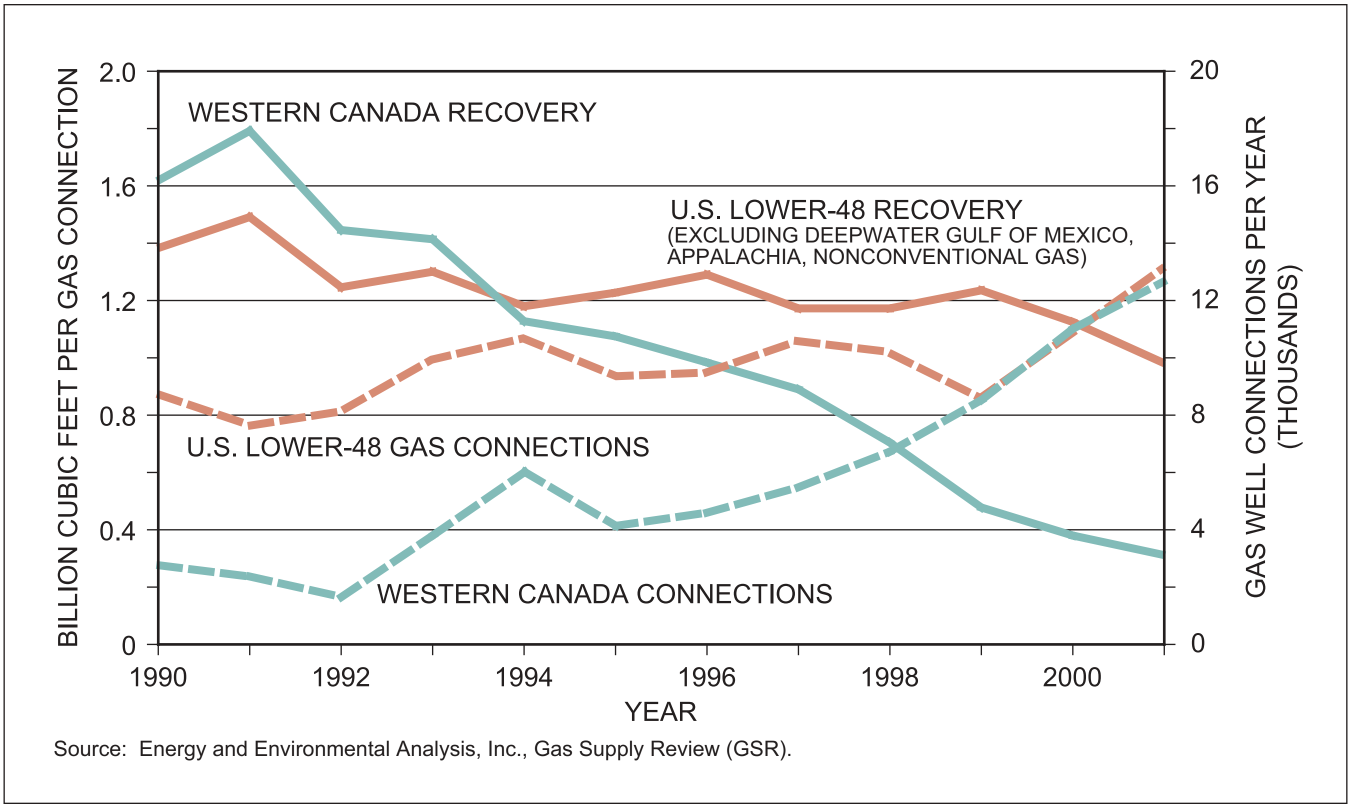


Figure S4-3. Estimated Ultimate Recovery per Gas Well Connection

mid-1990s helping the industry to maintain production levels, as the industry aggressively employed fracture stimulation technology. Increases in IPs flattened in the later part of the 1990s as per well reserves continued to decline and fracture stimulation implementation neared saturation level in most basins.

Increases in IPs and falling EURs have led to markedly increased per well decline rates. In the early 1990s, first year declines averaged between 30 and 40%. By 2000-2001, that decline had increased to 50% to greater than 60% for non-coal bed wells. (See Figure S4-4.)

As completion technology has allowed the industry to accelerate per well production and per well recoveries have fallen, overall base decline rates have progressively steepened, requiring the industry to work harder just to stay even. In 1992, with a base decline rate of 17%, to hold production flat, gas wells drilled and brought onto production in 1992 had to replace 8 BCF/D. By 2000 and 2001, the base decline rate had steepened to 26%-27%, and the industry had to replace almost 13 BCF/D, more than 50% higher, just to maintain flat production levels. (See Figures S4-5 and S4-6.)

In contrast to the difficulty the industry has experienced in increasing production volumes, total Proved Reserves have increased rather strongly in the U.S. lower-48 from 154 TCF at the beginning of 1999 to 175 TCF of dry gas by the end of 2001. Regionally, much of the increase has come from the Rockies and other areas characterized by significant amounts of nonconventional gas reserves. Essentially all of the increase in Proved Reserves has come from Proved, Non-Producing Reserves.

C. Drilling and Production History

1. U.S. Lower-48

a. Rig Count and Gas Well Connections

Industry activity levels for natural gas exploration, development, and production, as measured by rig count and gas connections have historically exhibited a strong correlation to the price of natural gas. The early 1990s were characterized by low gas prices ($1.75 average Gulf Coast Spot Price) and a gas rig count of approximately 400 rigs. Gas prices rose in the 1997-1999 period, averaging $0.45/MMBtu higher, or $2.20/MMBtu. As prices rose, the gas rig count rose to

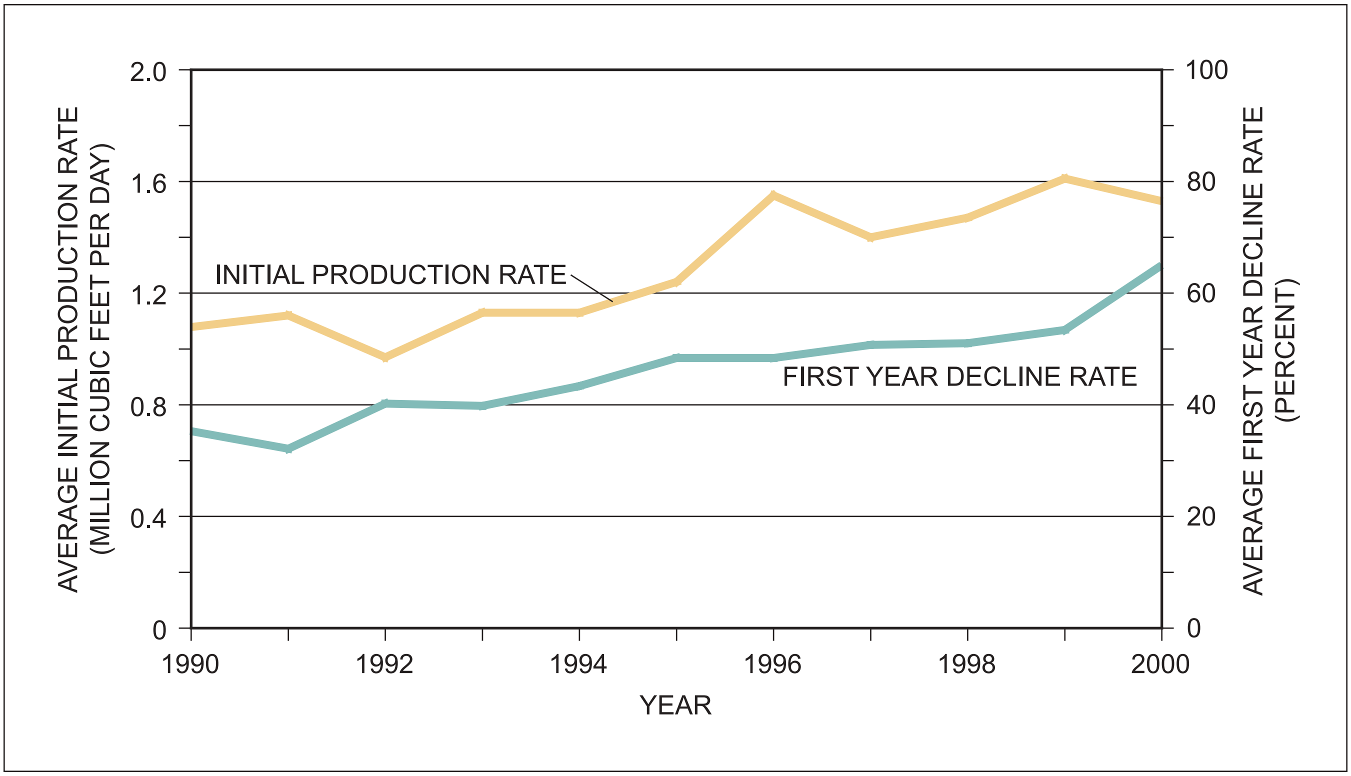


Figure S4-4. Initial Production Rates and First Year Decline Rates (U.S. Lower-48, Non-Coal Bed Methane)

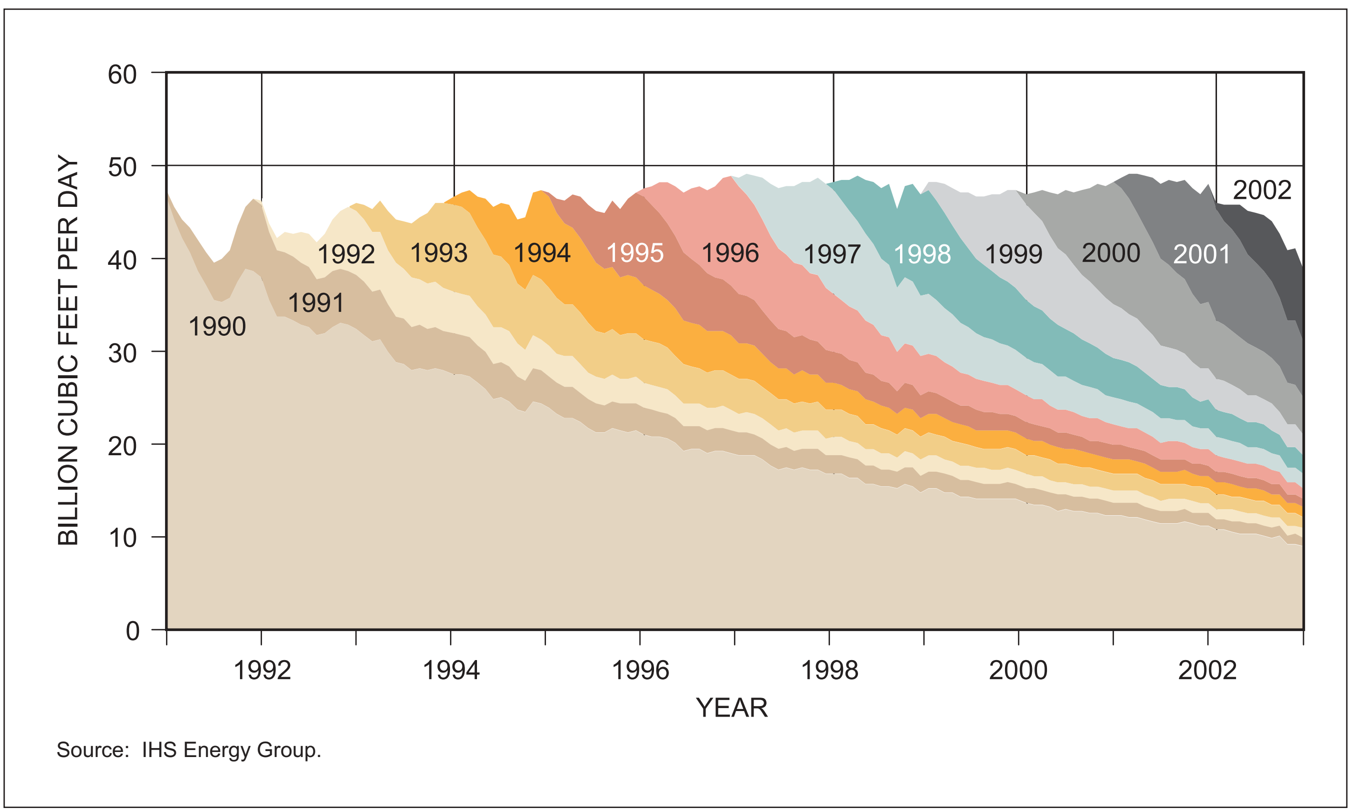


Figure S4-5. U.S. Lower-48 – Daily Wet Gas Production from Gas Wells, by Year of Production Start

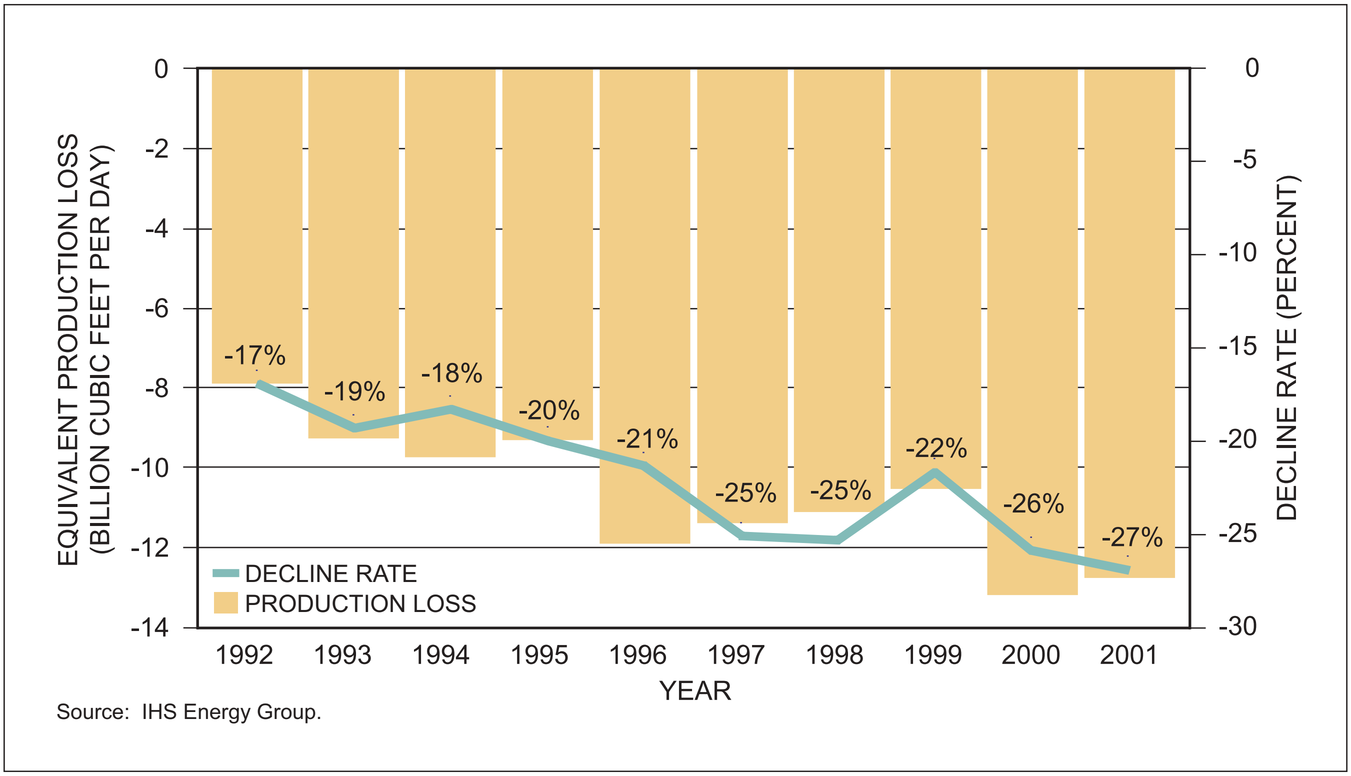


Figure S4-6. U.S. Lower-48 – Decline Rate of Base Gas Production if No New Wells had been Drilled, and Equivalent Production Loss

an average of 540 rigs. Gas prices continued to climb and Gulf Coast Spot Prices averaged $3.65/MMBtu from 2000 through 2002. As prices increased, rig activity also rose, with an average gas rig count of 780 rigs over the period. In June 2003 the rig count stood at approximately 900 gas rigs and a Gulf Coast Spot Price at $5.80. (See Figure S4-7.)

As measured by gas well completions, a similar pattern of increasing activity emerges and is shown in Figure S4-8. In the early part of the decade, the industry averaged 400 gas rigs and 9,700 gas completions per year. As the rig count increased by 35% to 540 gas rigs during the 1997-1999 period, average gas completions rose by 25% to 12,100 gas completions per year. Over the last three years, gas completions have increased to 19,300 gas completions per year, almost double what they were averaging a decade before.

Annual connections (completions + sidetracks + re-completions) showed similar behavior (see Figure S4-9). As drilling ramped up again in 2000 and 2001, annual connection levels rose to above 22,000 in 2001, an increase of approximately 9,000 connections from 1999. Another trend became obvious in 2000-2001, the increasing importance of nonconventional drilling. Coal bed methane connections rose from 625 connections in 1996 to over 5,000 connections in 2001, as drilling ramped up in the Powder River Basin. Shale connections have also increased recently as drilling ramped up in East Texas, targeting the Barnett Shale.

b. Lower-48 Production Response

U.S. lower-48 production has increased from 47.0 BCF/D in 1990 to an estimated 50.9 BCF/D in 2002, an annual growth rate of 0.7% p.a. Most of the sustained production growth occurred in the early 1990s; however, this was partially due to a change in demand patterns, rather than a true increase in wellhead deliverability. Peak production rates remained generally flat year to year. (See Figure S4-10.)

While an average rig count of 400 enabled the industry to produce peak rates of 50 BCF/D in the early 1990s, the later half of the 1990s has been characterized by two industry drilling/production cycles (1997-1999 and 2000-2002). In response to increased price, gas drilling ramped up in 1997 and 1998. By increasing the

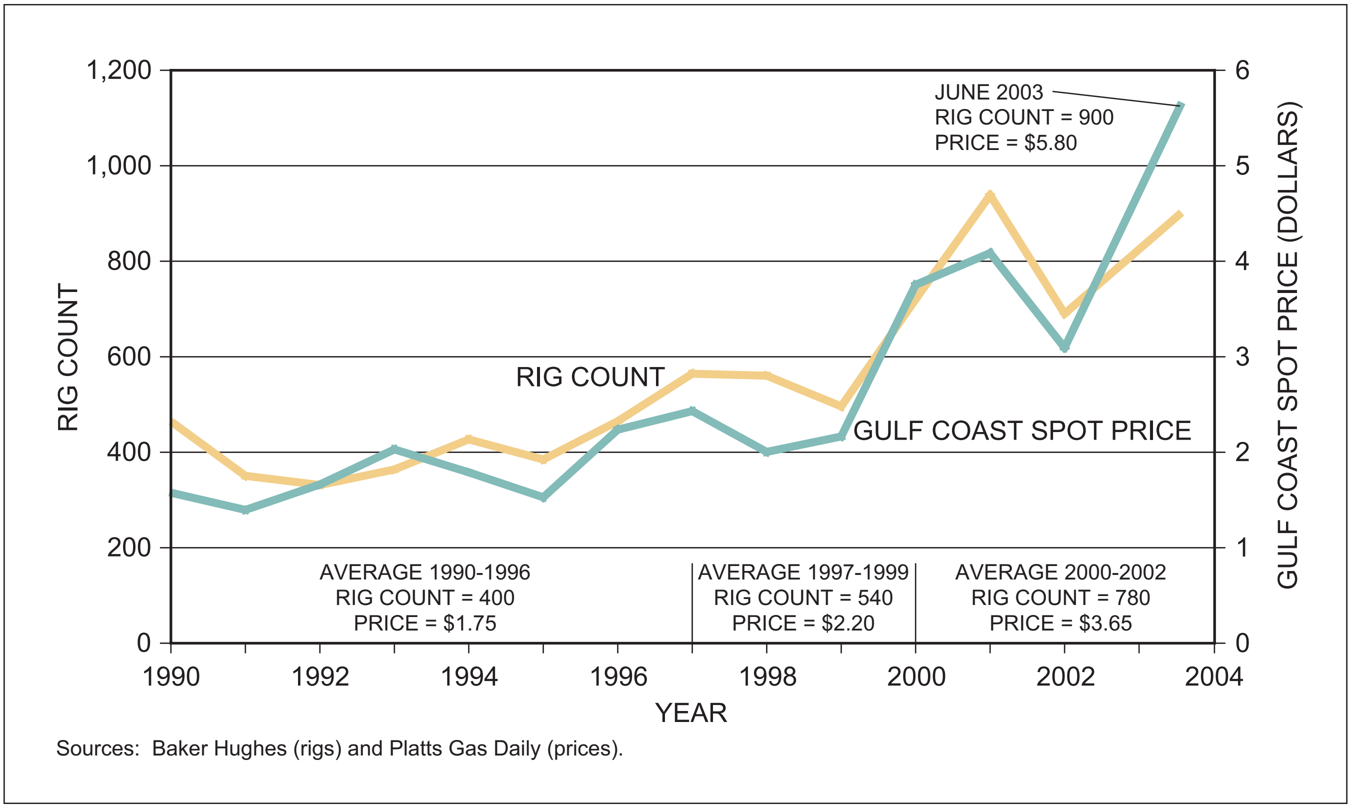


Figure S4-7. U.S. Lower-48 – Gas Rig Count and Gulf Coast Spot Price

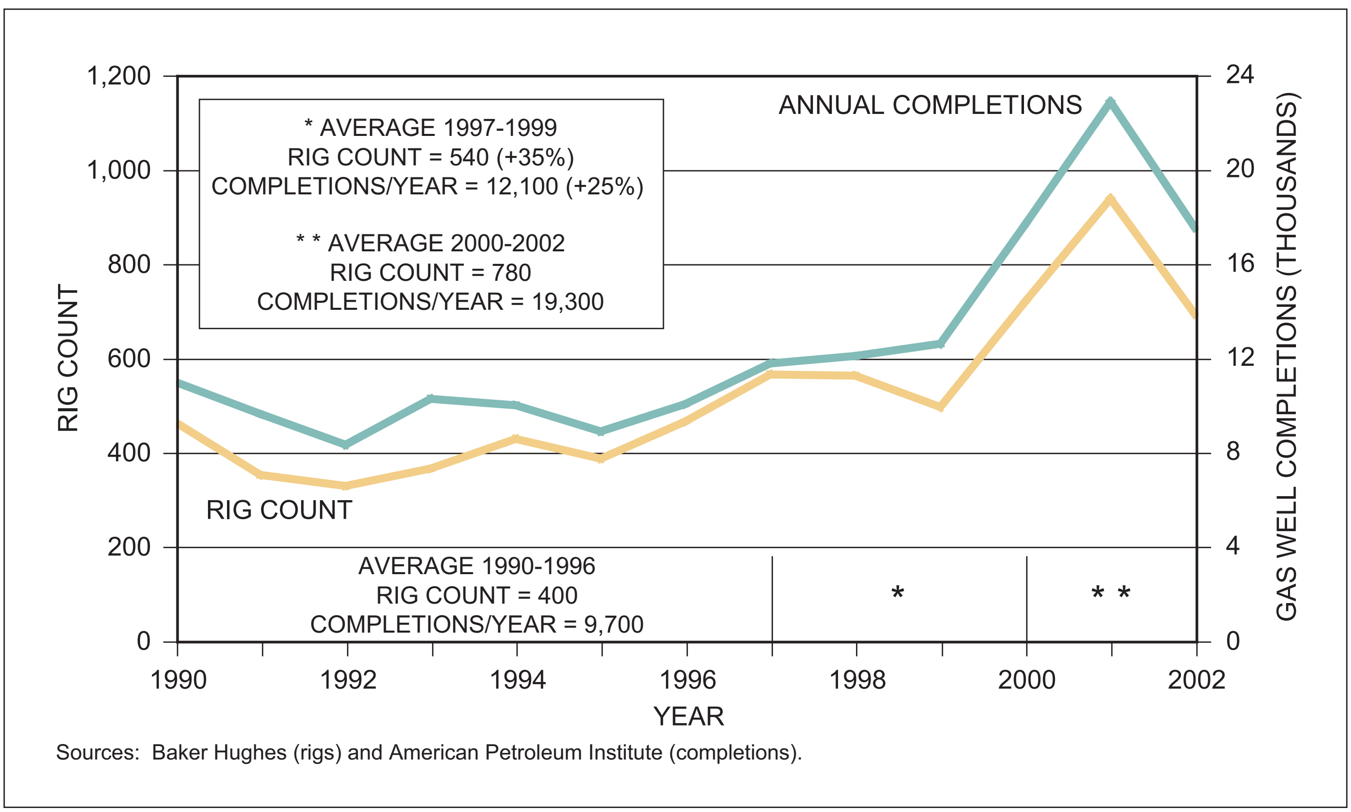
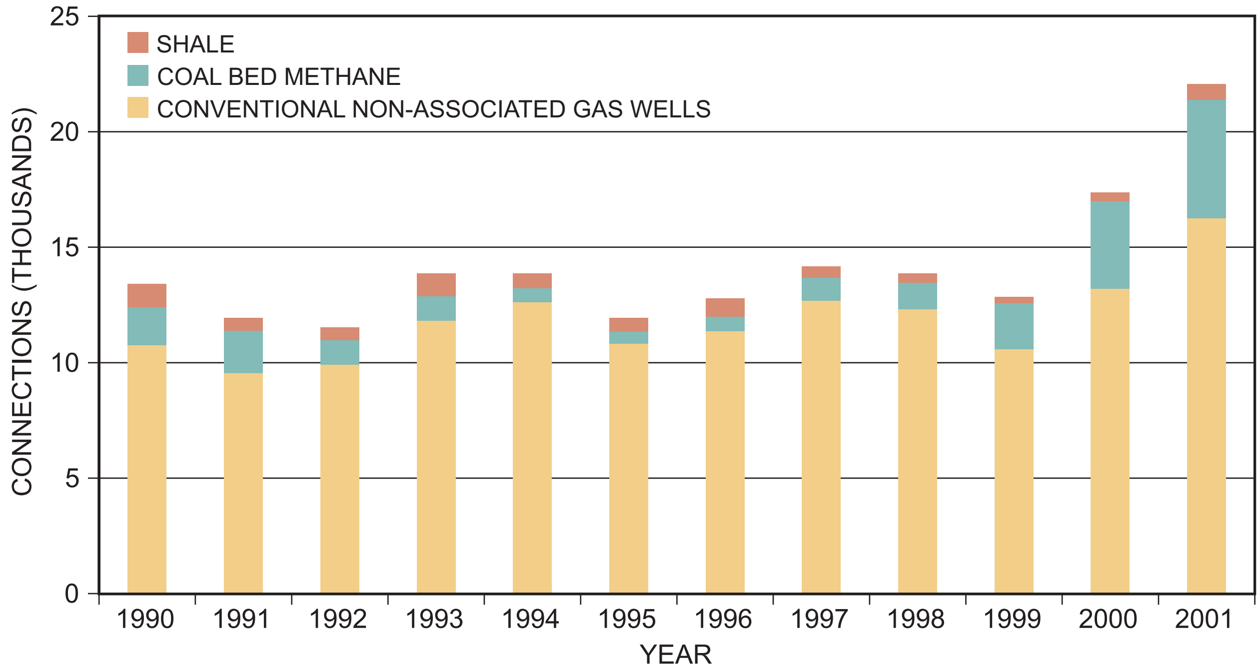
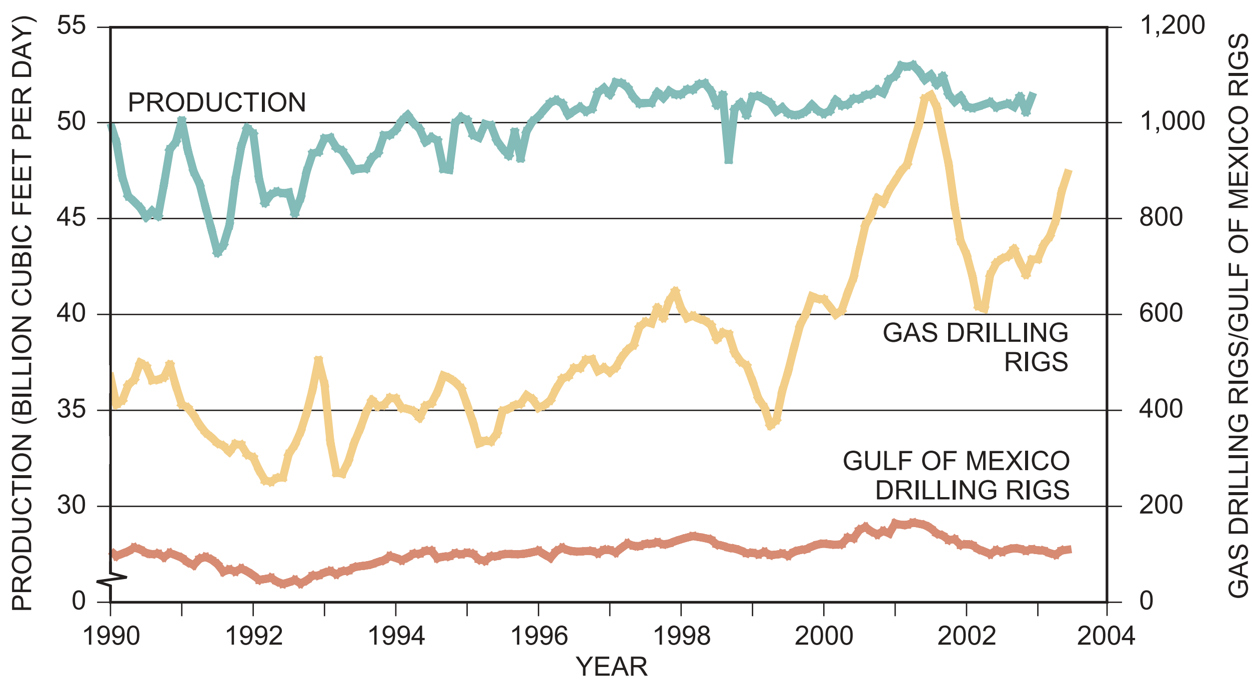


Figure S4-8. U.S. Lower-48 – Gas Rig Count and Gas Well Completions



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-9. U.S. Lower-48 – Annual Gas Well Connections



Sources: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR); Baker Hughes.

Figure S4-10. U.S. Lower-48 – Total Gas Production and Rig Count gas rig count from 400 to 650 the industry was able to increase production by 2 BCF/D. Following the peak in late 1997, production gradually fell off as activity levels declined. Drilling ramped up very strongly in late 1999, 2000, and early 2001. In the 2000-2002 cycle, it required a rig count which increased from 400 to over 1,050 rigs, nearly double the peak rates in 1997 to increase production a roughly similar amount. When prices fell and drilling slowed to an average of 700 rigs in 2002, still above the peak rig count in 1996-1998, production fell dramatically.

c. Drilling Footage

Average footage per completion outside of the Rocky Mountains, where completions are dominated by shallow coal bed methane drilling in the Powder River Basin, have increased over the last 5 years (see Figure S4-11). In the Gulf of Mexico, average footage per completion has increased from 9,400 feet in 1998 to 10,900 feet in 2002, an increase of 1,500 feet per completion. Onshore, while completions have become shallower in certain basins (e.g., Midcontinent, Permian Basin), footage per average completion has increased from 6,350 feet in 1998 to 6,700 feet in 2002, an increase of 350 on average. Average footage per completion increased from 7,900 feet in 1998 to 9,200 feet in 2002 in East Texas/North Louisiana. In the South Texas Gulf Coast, average footage per completion increased from 9,000 feet to 9,550 feet over the same period.

2. Western Canada

Since 1990, 65% of the incremental supply of North American gas has come from increasing Canadian production, primarily from the Western Canada Sedimentary Basin. However, production growth in Western Canada has slowed dramatically, so much so that 2002 was the first year that the Western Canada Sedimentary Basin experienced declining production. In the early 1990s, as gas export infrastructure grew, Western Canadian production grew by 4.5 BCF/D from 1990 to 1995, from an average of 3,000 gas wells per year. Growth rates slowed through the rest of the 1990s, even as gas completions peaked at over 10,500 gas completions in 2001, or over 3 times the completions in the beginning part of the decade. The 2001 and 2002 production rates were boosted by significant production from the Ladyfern Field in British Columbia, a field that is already on decline. (See Figures S4-12 and S4-13.)

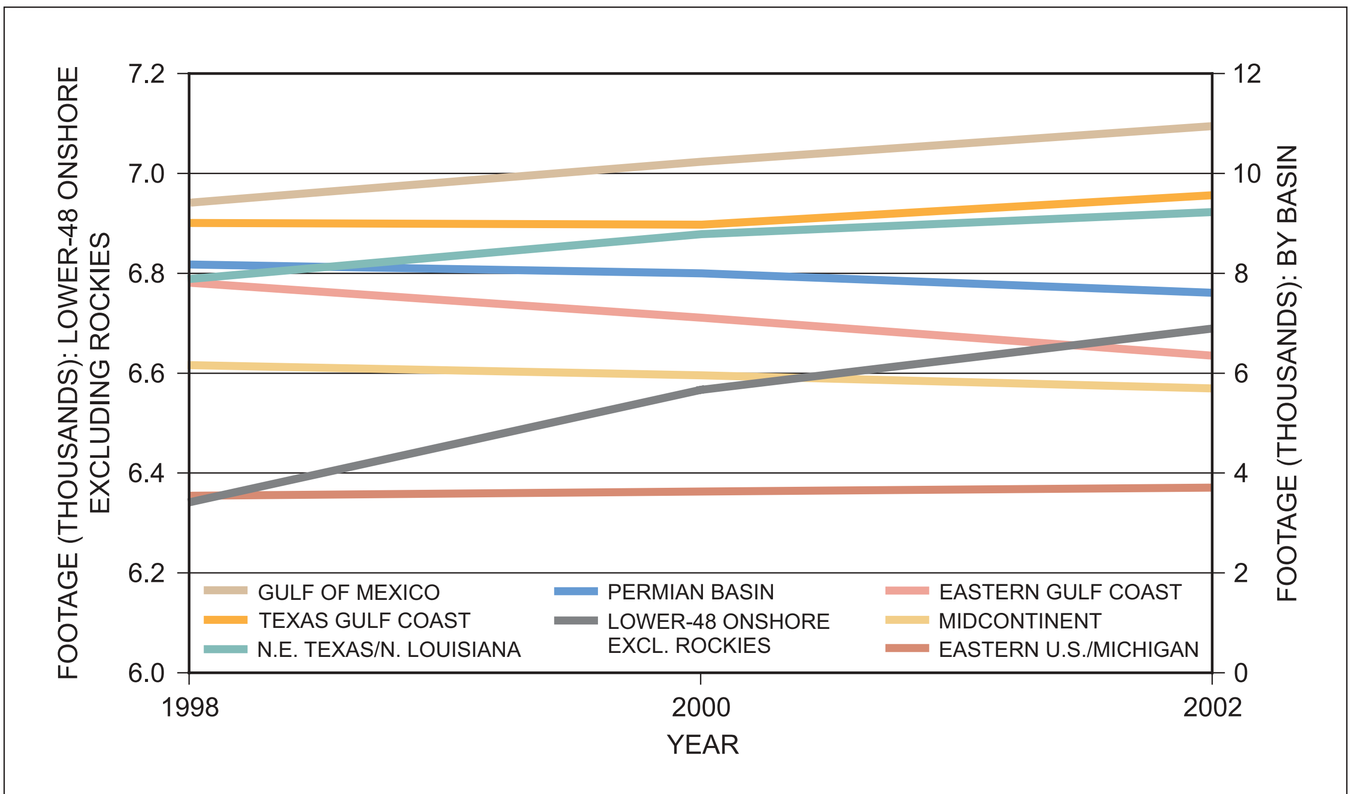


Figure S4-11. Average Footage per Completion

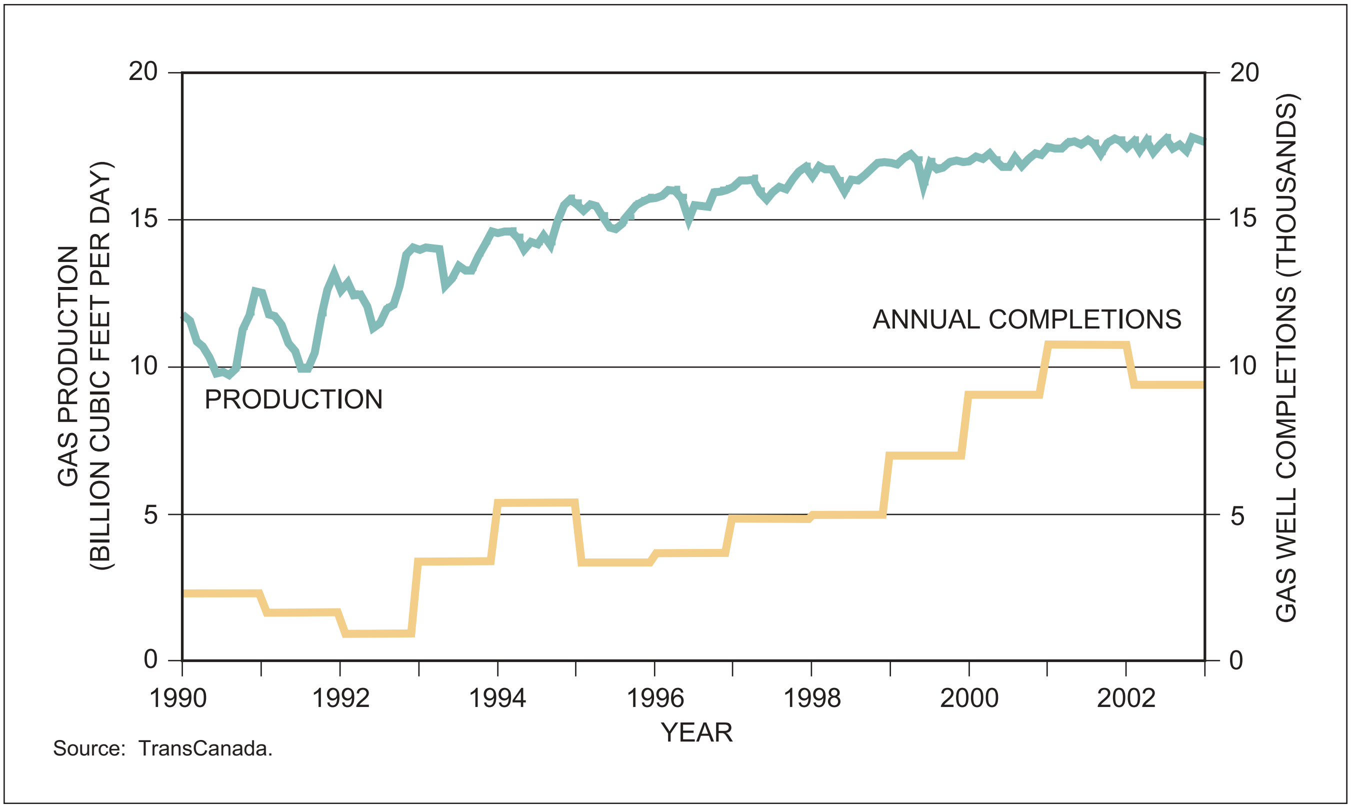


Figure S4-12. Western Canada Sedimentary Basin – Production and Gas Well Completions

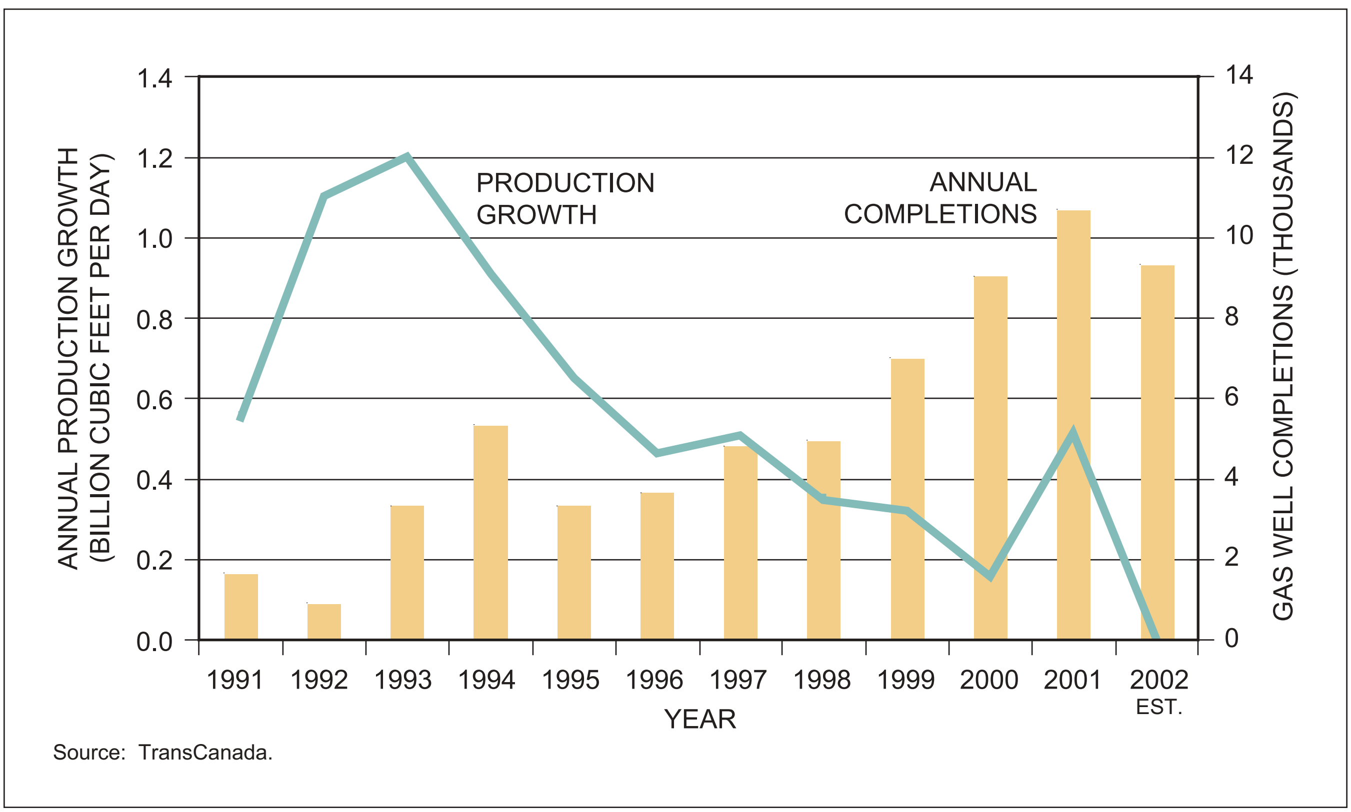


Figure S4-13. Western Canada Sedimentary Basin – Production Growth and Gas Well Completions

D. Individual Gas Well Performance

Individual gas well performance was analyzed using three parameters: (1) Estimated Ultimate Recovery, (2) Initial Production Rate, and (3) Initial Decline Rate.

1. Estimated Ultimate Recovery (EUR)

Estimated Ultimate Recovery or EUR is an estimate of the amount of gas an individual gas well connection will produce over its economic life. EURs generally decline as basins mature, as the industry targets and exploits the larger, more economic prospects first. However, EUR trends can be complicated by a number of factors:

- Technology (e.g., 3-D seismic opening deeper, under-explored parts of the basin)
- Well Mix (e.g., targeting shallow, low-risk exploitation wells vs. higher risk exploration wildcats)
- Economics (e.g., increase in gas prices spurring rapid development of in-fill locations)
- Basin character, reserve type, and other items.

During the 1990s the average EUR per gas connection in the U.S. lower-48 fell from 1.4 BCF/connection in 1990 to 1.2 BCF/connection in 1999, a decline of 15%. As drilling and completion activity increased significantly in 2000 and 2001, average EUR/connection fell a further 15% to just under 1 BCF. (See Figure S4-14.)

In Western Canada, EURs have shown even a more marked decline, falling from about 1.7 BCF in the early 1990s, to 0.3 BCF in 2001, as annual completions increased from approximately 3,000 per year in the early 1990s to over 10,000 in 2001. (See Figure S4-14.)

The GOM Shelf showed a much more rapid fall-off in EURs than onshore. On the Shelf, EURs fell 34% between 1990 and 1999 from 5.1 BCF/connection to 3.3 BCF/connection. (See Figures S4-15 and S4-16.) EURs for onshore gas connections trended down from 1.1 BCF in 1991 to 0.9 BCF in 1997, rebounded back to 1 BCF in 1999, before falling in 2000 and 2001 as activity levels increased. (See Figures S4-17 and S4-18.)

Onshore well productivity trends have been basin specific, from steady declines in EUR/connection in the Midcontinent/Anadarko Basin to rising average well productivity in the Rocky Mountains and Texas Gulf

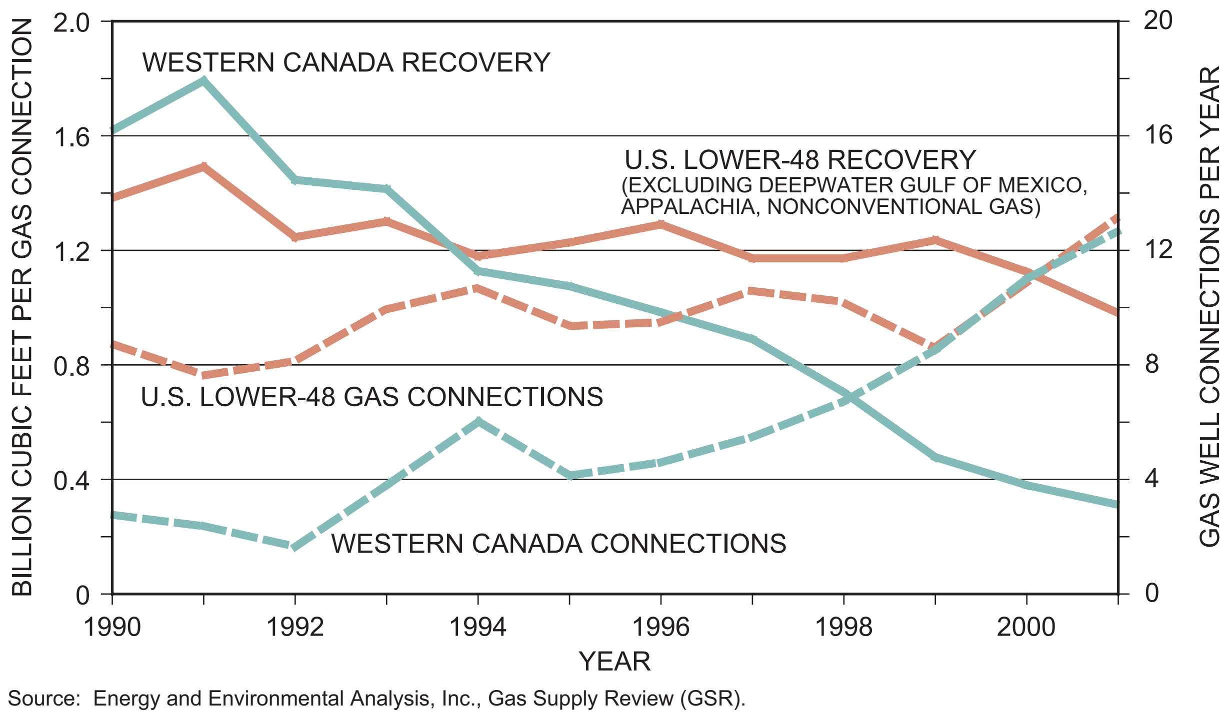
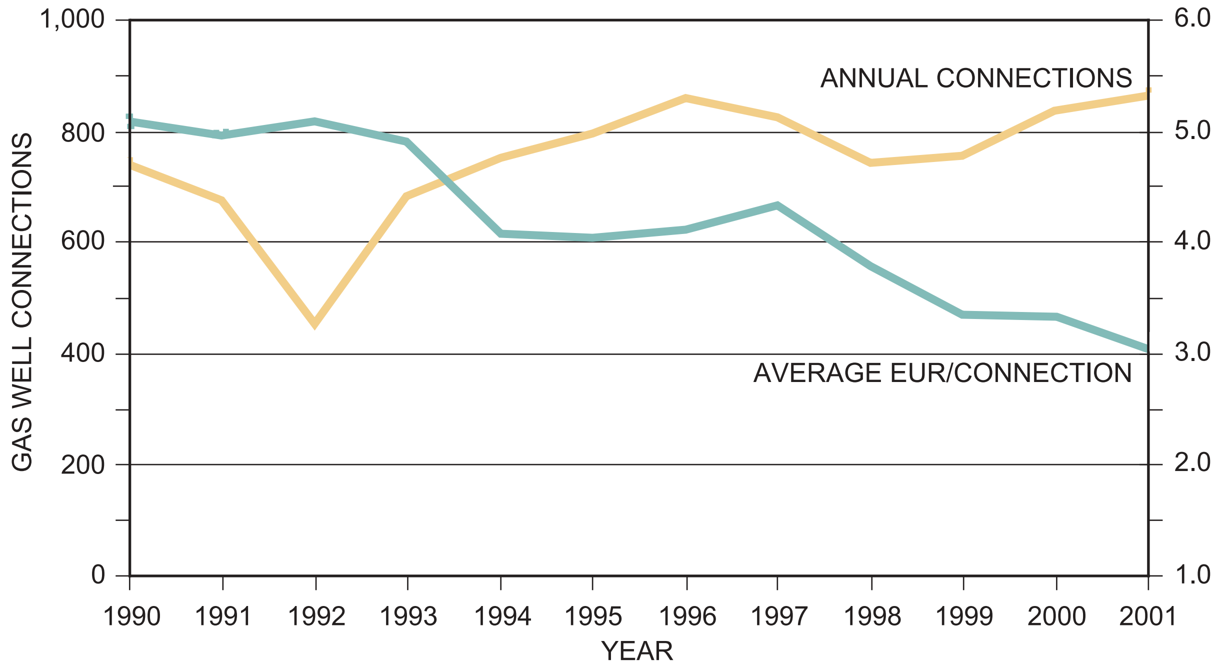
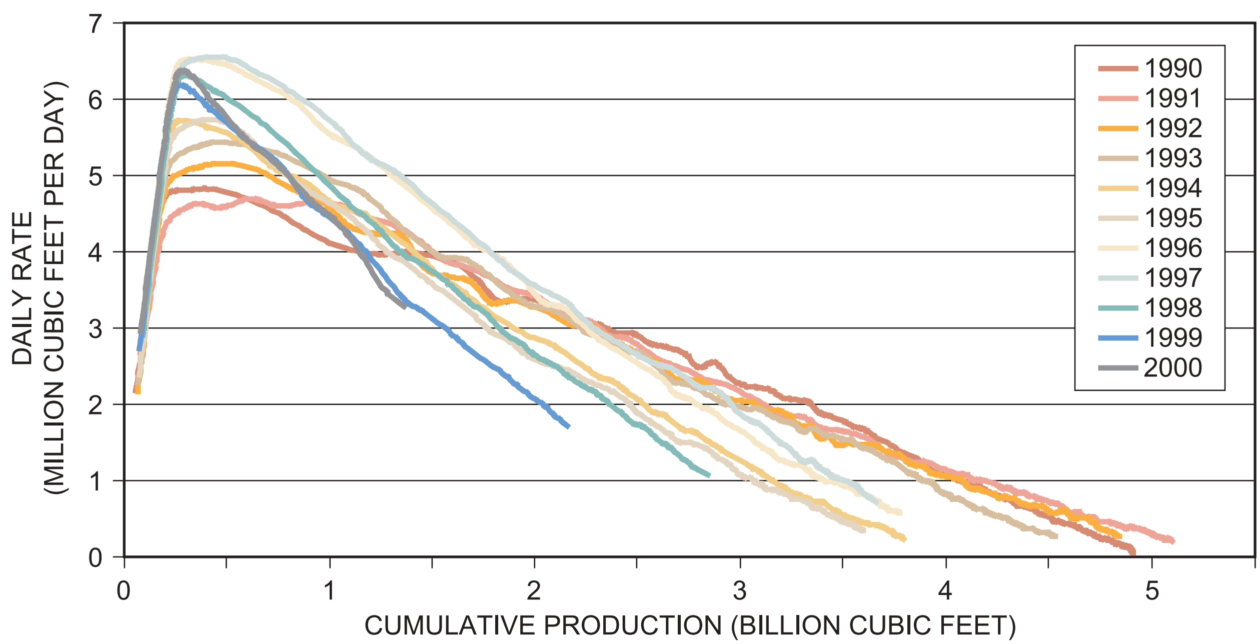


Figure S4-14. Estimated Ultimate Recovery per Gas Well Connection



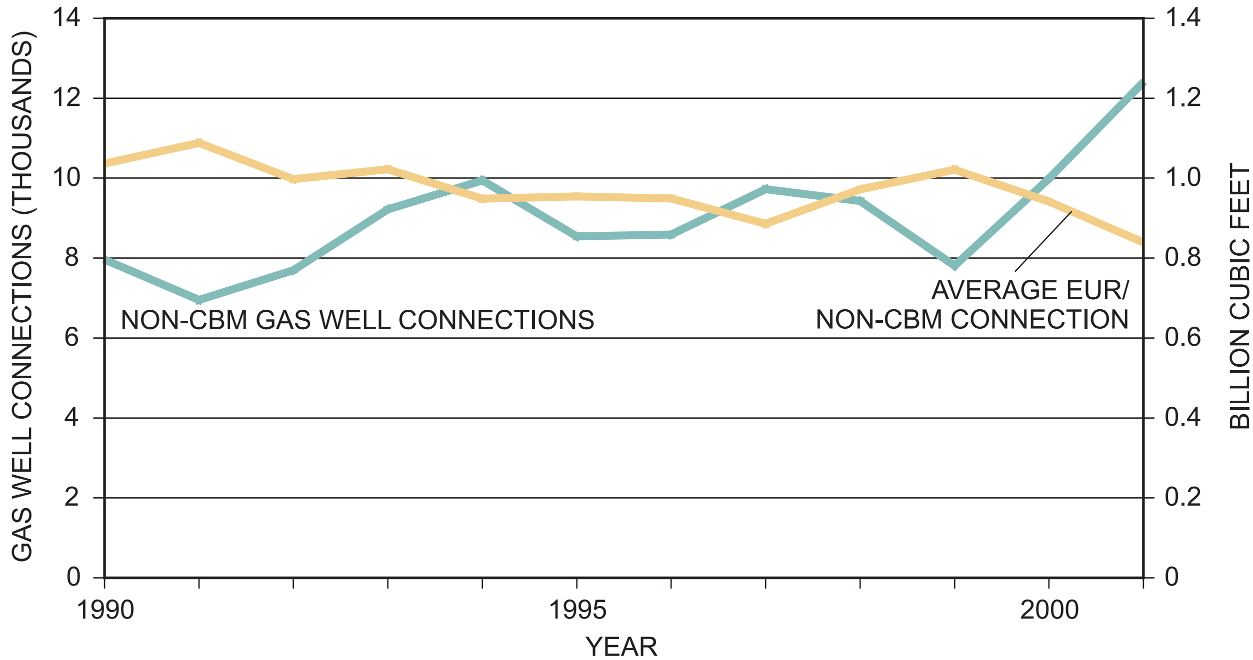
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-15. Gulf of Mexico Shelf – Recovery per Gas Well Connection (Excludes Norphlet)



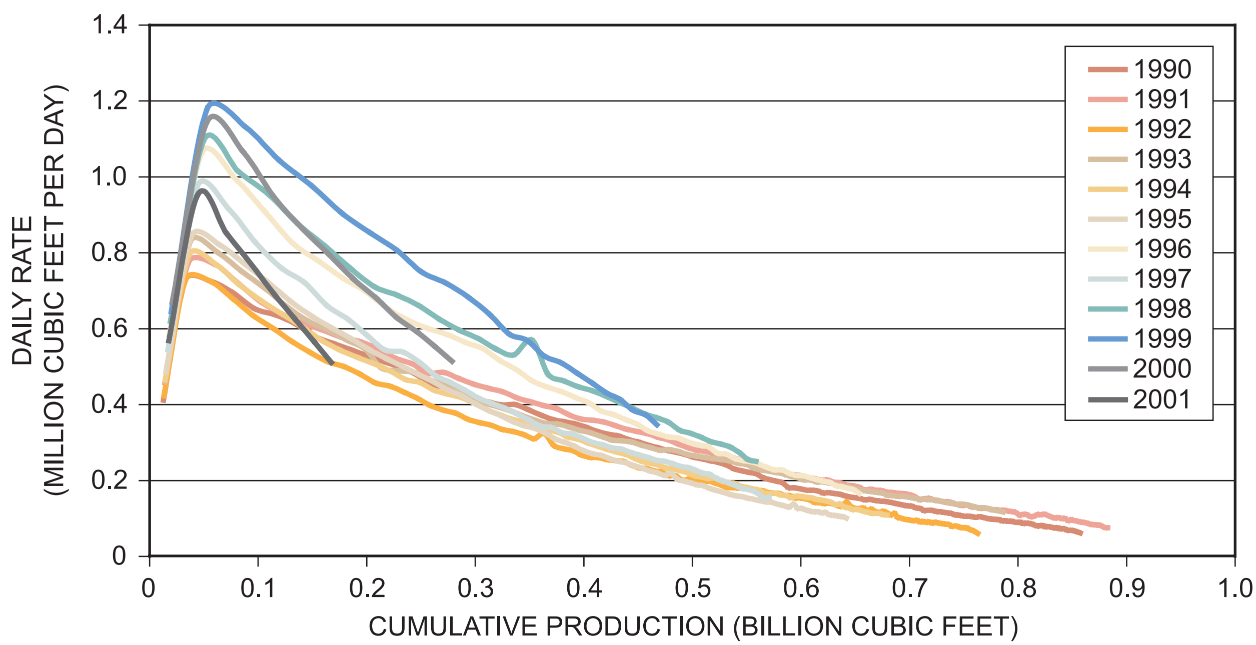
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-16. Gulf of Mexico Shelf – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-17. U.S. Lower-48 Onshore – Non-Coal Bed Methane Gas Connections and Average EURs



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-18. U.S. Lower-48 Onshore Conventional – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production

Coast. In each basin, well productivity has evolved for different reasons; new play ideas have emerged, new seismic or fracture stimulation technology or horizontal drilling has been utilized. For example, in the Green River Basin, production rates and average well EURs have increased dramatically over the past few years as fracture stimulation techniques have been applied at the Jonah Field, originally discovered in 1975. On the Texas Gulf Coast, high-resolution 3-D seismic has been shot across the basin, allowing the industry to image traps more accurately and exploit the deeper, less mature parts of the basin. And in the mature fields of East Texas, new fracture stimulation techniques have allowed very tight sands to be economically produced. (See Table S4-2.)

2. Initial Production Rates (IPs)

In a period of falling EURs, the industry has been able to partially compensate by accelerating individual well production. As regulatory constraints on gas well production were eased in the early part of the 1990s, the rapid application of completion and stimulation technology, combined with producers' economic drive to lower R/P ratios, caused IPs to increase rapidly. Average gas well IPs increased from 1.1 MMCF/D in 1990 to just under 1.6 MMCF/D by 1996. Average IPs remained at about that level in the late 1990s and increased to an all-time peak in 1999 of 1.6 MMCF/D before falling in 2000. (See Figure S4-19.)

On the GOM Shelf, peak rates and plateau times reached their all-time maximum in the 1996-97 time frame. Since then peak rates have fallen marginally and plateaus have shortened noticeably. (See Figure S4-20.) Onshore, IPs rose rapidly to 1996, but continued to rise marginally through the later half of the decade. IPs fell marginally in 2000, and then more substantially during the 2001 drilling ramp-up. (See Figure S4-21.)

One of the drivers of the increase in IPs has been the increasing application of fracture stimulation technology. More wells are being fracture stimulated and often with larger stimulations. Stimulation technology has also advanced, allowing longer fracture lengths to more rapidly drain larger areas of tight reservoir. In East Texas, for example, while a significant percentage of wells were fracture stimulated in the early part of the decade, that percentage increased until almost 100% of completions are now fracture stimulated. East Texas is characterized by tight reservoirs and accordingly a high percentage of completions are fracture stimulation, but many other basins are also reaching a high level of utilization. The trend of increasing IPs from fracture technology that was

	Change (%)				EUR (Billion Cubic Feet)				
	1990-2001	1990-1996	1996-1999	1999-2001	1990	1996	1999	2000	2001
Lower-48 Onshore (non Appalachian)									
Coal bed	-70	-62.9	-1.8	-16.4	2.13	0.79	0.78	0.54	0.65
Non-Coal bed	-19	-8.6	7.5	-17.4	1.04	0.95	1.02	0.94	0.84
Rockies									
Coal bed	-84	-75.3	-24.3	-16.7	4.60	1.14	0.86	0.57	0.72
Non-Coal bed	47	14.4	26.6	1.8	0.76	0.87	1.10	1.12	1.12
Midcontinent	-53	-27.8	-18.9	-19.5	1.08	0.78	0.63	0.63	0.51
Permian Basin	-22	-11.7	43.3	-38.3	0.78	0.69	0.99	0.83	0.61
East Texas/North Louisiana	-23	2.2	-18.1	-8.5	0.93	0.95	0.78	0.75	0.71
South Texas Gulf Coast	13	31.8	5.3	-18.4	0.91	1.19	1.26	1.19	1.03
Eastern Gulf Coast	-45	-40.2	56.9	-41.0	2.56	1.53	2.40	1.47	1.42
GOM Shelf (excl. Norphlet)	-37	-18.5	-18.5	-5.4	4.99	4.06	3.31	3.28	3.13

Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Table S4-2. U.S. Lower-48 EUR per Gas Connection

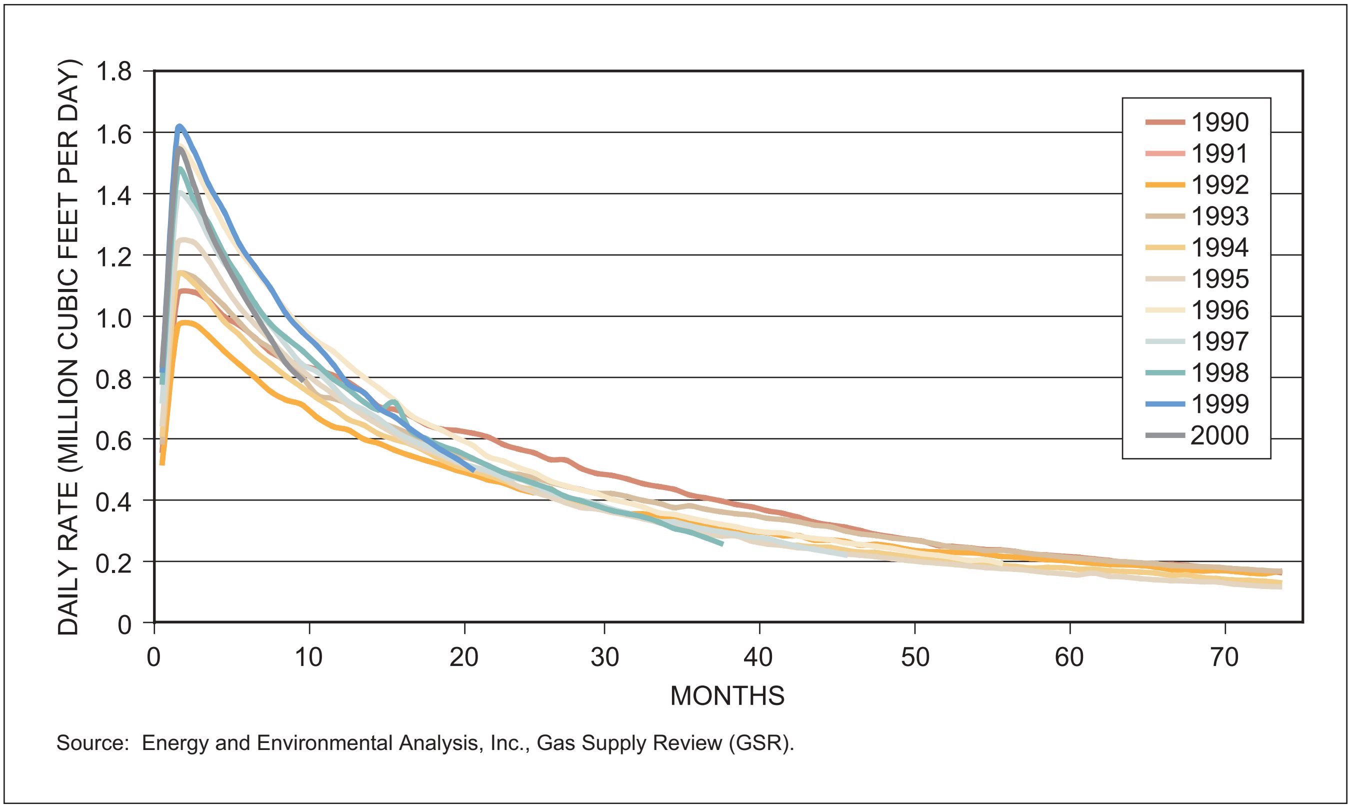


Figure S4-19. U.S. Lower-48 Conventional – Average Daily Gas Well Production vs. Time, by Year of First Production

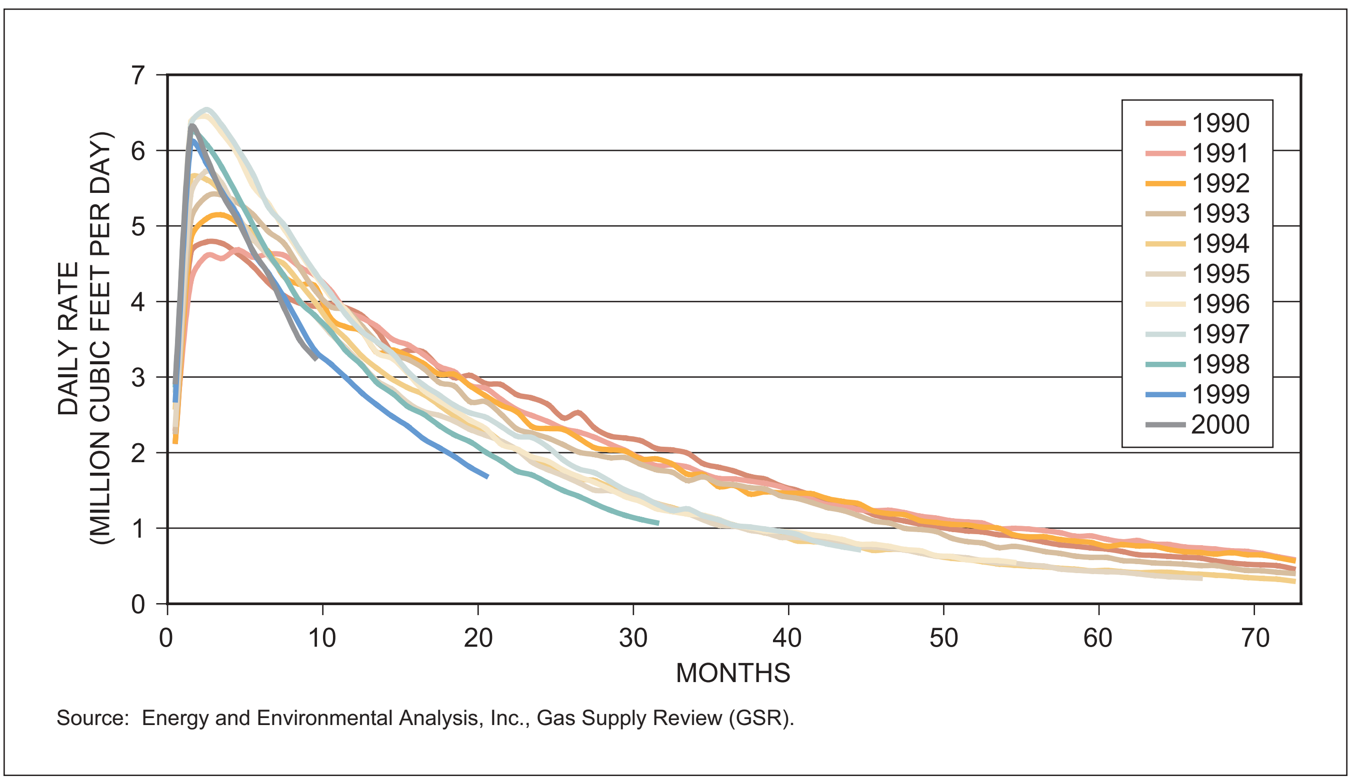


Figure S4-20. Gulf of Mexico Shelf Conventional – Average Daily Gas Well Production vs. Time, by Year of First Production

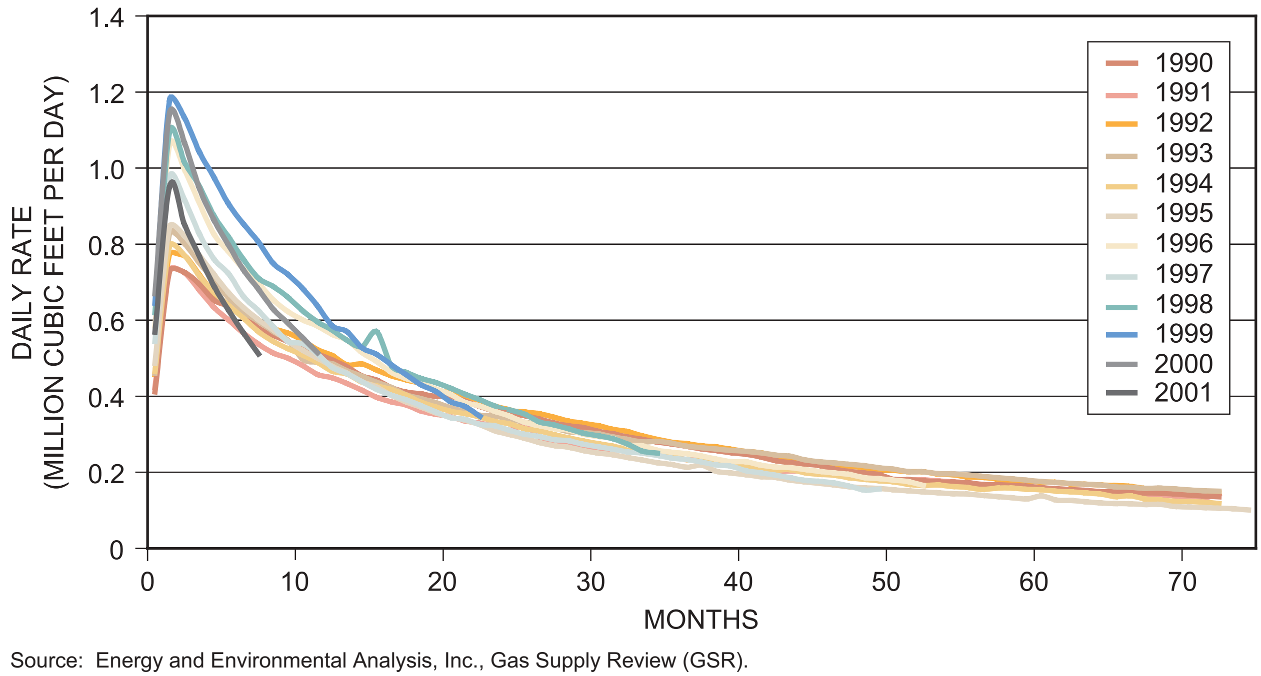


Figure S4-21. U.S. Lower-48 Onshore Conventional – Average Daily Gas Well Production vs. Time, by Year of First Production

enjoyed through the middle of the 1990s will likely not be continued. (See Figure S4-22.)

3. Initial Decline Rates

As EURs have been falling and IPs have increasingly been bringing production forward, decline rates have been progressively steepening. While both the onshore and GOM Shelf have witnessed increasing decline rates, the effect has more pronounced on the GOM Shelf, with its rapidly falling EURs. (See Table S4-3 and Figures S4-23, S4-24, S4-25, and S4-26.)

E. Base Decline Rates

As the industry has continued to add high decline wells to base production, the overall decline rate has increased. In 1992, the base decline rate was 17%. To simply hold production flat, the 1992 gas drilling program needed to replace 8 BCF/D.

Over the period, the base decline rate has steepened, and perhaps more importantly, the amount of production from new gas wells required to simply maintain production levels has dramatically increased. To

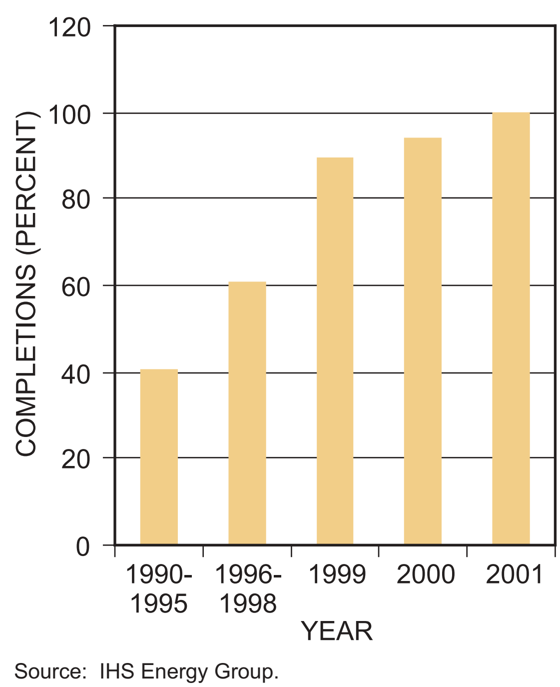


Figure S4-22. Percentage of Completions in East Texas that were Fracture Stimulated

	1990		1998		2000	
	1st Year Decline (%)	% of EUR Produced	1st Year Decline (%)	% of EUR Produced	1st Year Decline (%)	% of EUR Produced
E. Texas/ N. Louisiana	40	22	61	25	64	N.A.
South Texas Gulf Coast	41	27	62	34	67	N.A.
Anadarko Basin	28	12	52	21	58	N.A.
Permian Basin	40	16	37	17	53	N.A.
Gulf of Mexico Shelf (w/ Norphlet)	30	28	53	48	74	N.A.
Rockies (non-Coal Bed Methane)	38	12	44	16	64	N.A.

Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Table S4-3. Gas Well Decline Rates

keep production flat in 2000 and 2001, the gas drilling program had to replace over a quarter of production, or almost 13 BCF/D. As compared to just 10 years ago, the recent yearly drilling programs have had to replace an incremental 4-5 BCF/D, more than 50% higher, just to maintain production levels.

F. Proved Reserves

During the 1990s, the overall U.S. lower-48 proved reserve base remained remarkably consistent in total, beginning the decade at 158 TCF of gas and finishing the decade at 158 TCF. Over that period, lower-48 production totaled 177 TCF of gas. With a reserve

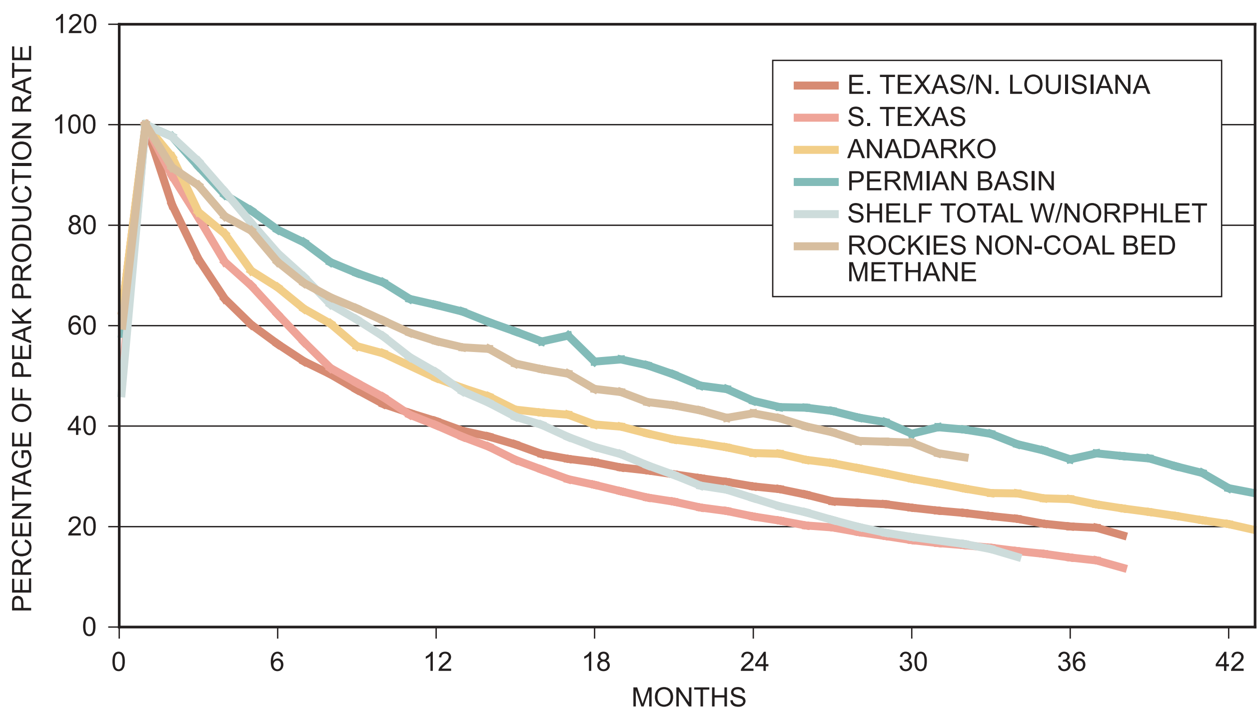


Figure S4-23. Comparative Well Profiles (1998 Vintage)

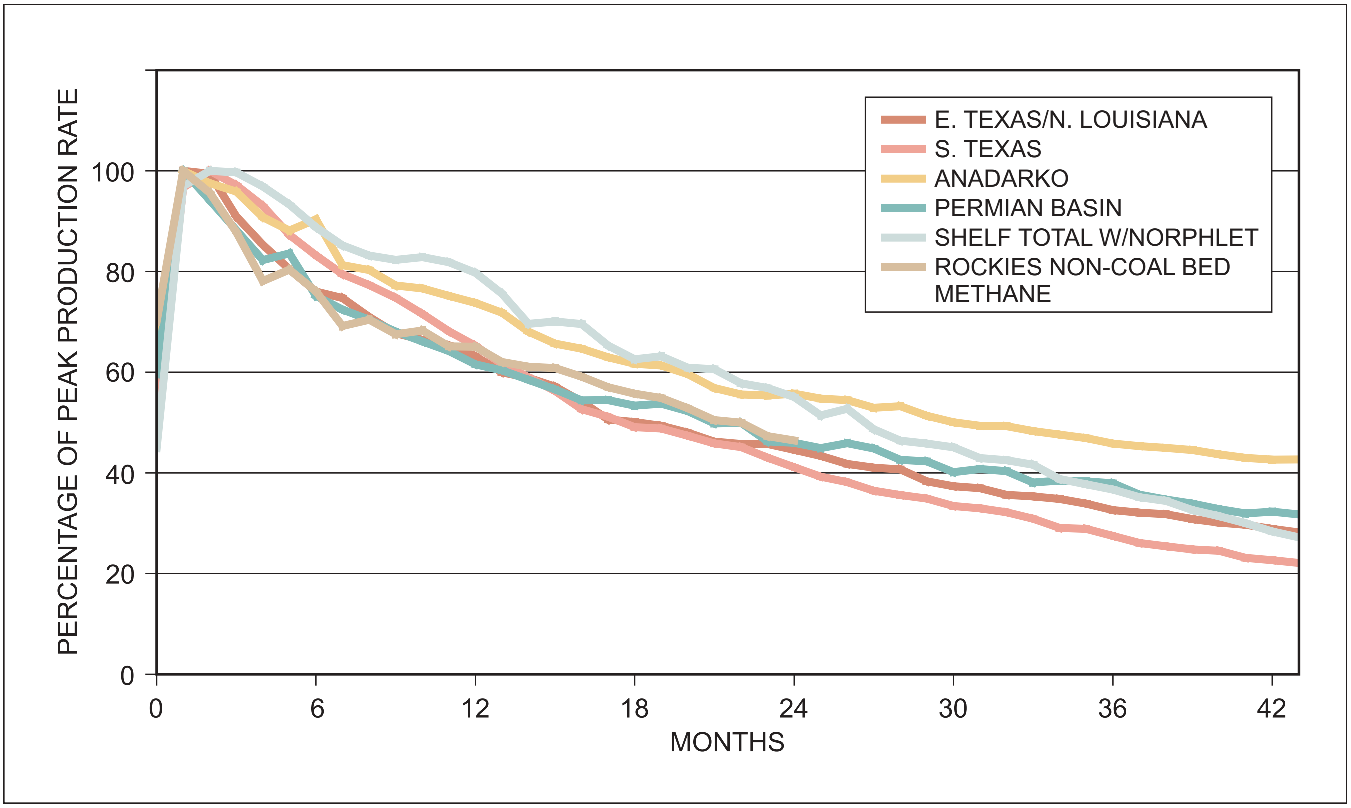


Figure S4-24. Comparative Well Profiles (1990 Vintage)

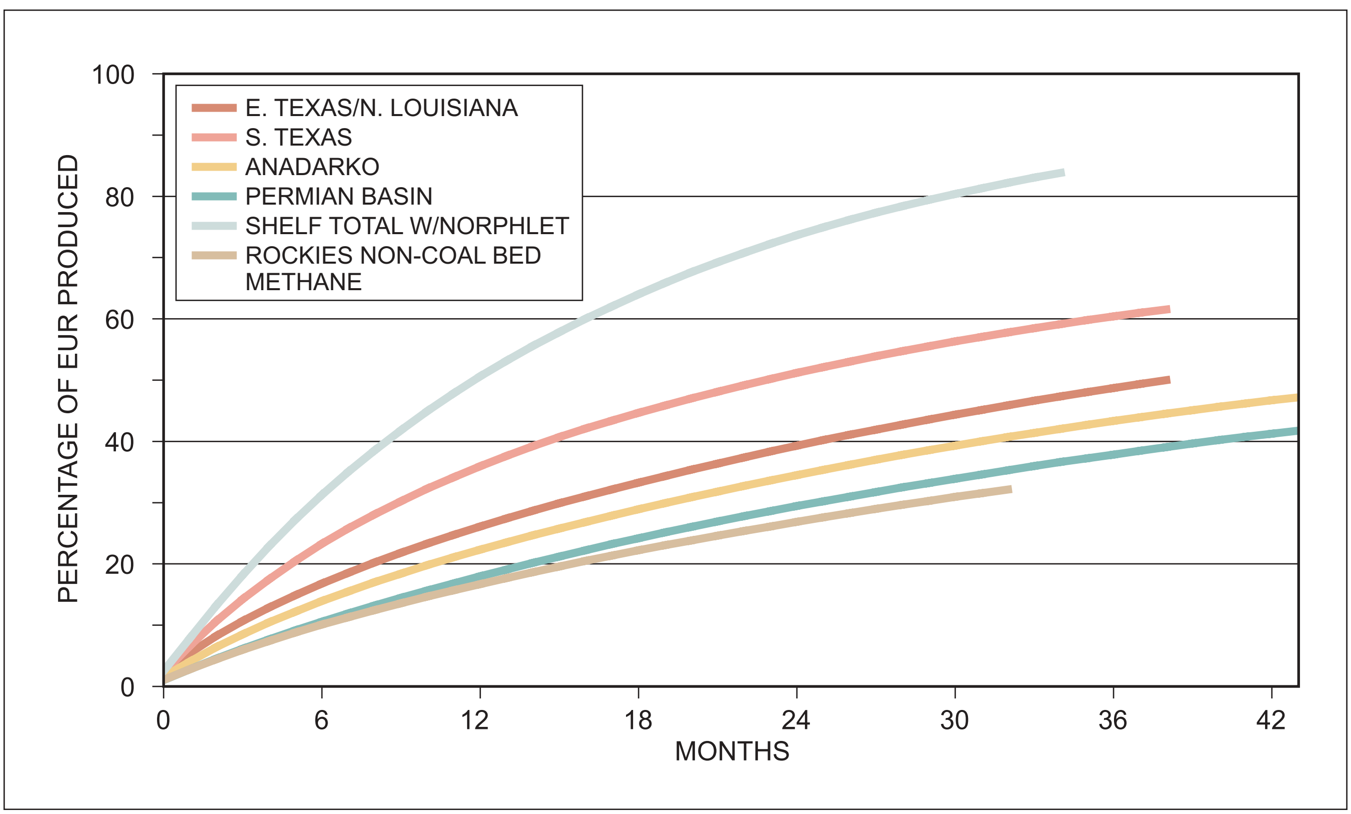


Figure S4-25. Comparative Well Profiles (1998 Vintage)

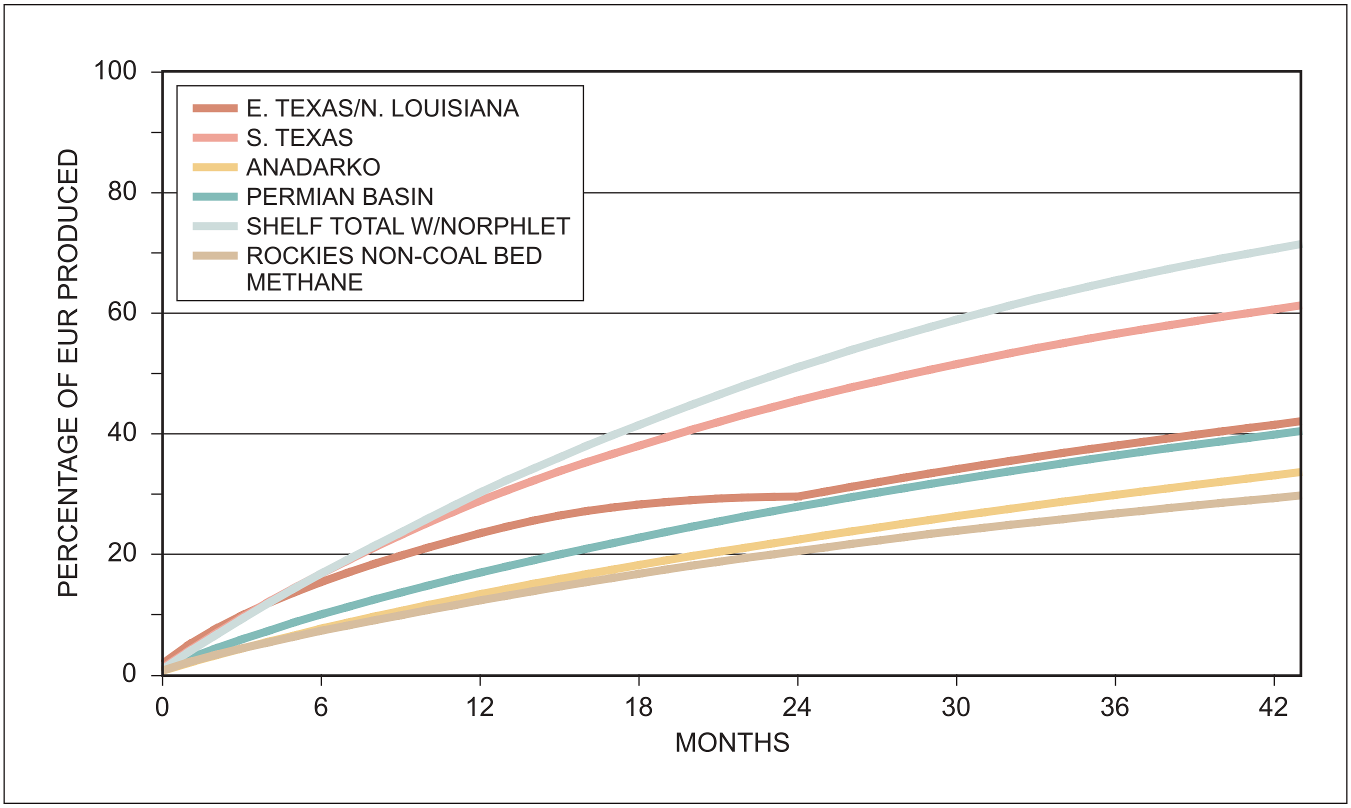


Figure S4-26. Comparative Well Profiles (1990 Vintage)

replacement percentage of exactly 100%, when measured over the decade, the industry proved 177 TCF of gas in the U.S. lower-48 in the 1990s. (See Figure S4-27.)

Reserve additions in 2000 and 2001 were about 9 TCF/year larger than the historical average. During 2000 and 2001, 39 TCF of gas were produced and 57 TCF of new reserves were added, resulting in Proved Reserves increasing by 18 TCF.

1. Regional Mix

On a regional basis, the last 6 years have disclosed some important changes in the Proved Reserve base. The two regions which have exhibited the strongest reserve growth, the Rocky Mountains and East Texas/North Louisiana, have both grown reserves by 40%, or a little over 18 TCF. During that period, these two regions increased their percentage of total reserves from 32% to 39%. Both areas have a significant percentage of nonconventional reserves. (See Table S4-4.)

Basins dominated by conventional reserves, either showed declines in reserves (i.e., the GOM, Midcontinent, Eastern Gulf Coast) or increased reserves only marginally (Texas Gulf Coast, Permian Basin).

2. Proved, Non-Producing and R/P

While the industry was able to increase Proved Reserves by almost 20 TCF from 1996 to 2001, Proved, Producing Reserves actually fell 2 TCF, from 133 TCF at the end of 1996 to 131 TCF at the end of 2001. In contrast, Proved, Non-Producing Reserves increased from 33 TCF at the end of 1996 to 52 TCF by the end of 2001.

3. Coal Bed Methane

U.S. coal bed methane reserves and reserve adds have increased significantly over the period, from less than 4 TCF of proved reserves at the beginning of 1990 to almost 18 TCF at the beginning of 2002. As production has also ramped up, R/P has fallen from almost 19 to 10. (See Figure S4-28.)

4. Western Canada

In Western Canada, the industry has generally not been able to replace production, and Proved Reserves and R/P have steadily fallen from 70 TCF of reserves with an 18 R/P in 1991 to an estimated 57 TCF of reserves with an R/P of approximately 9 in 2002. (See Figure S4-29.)

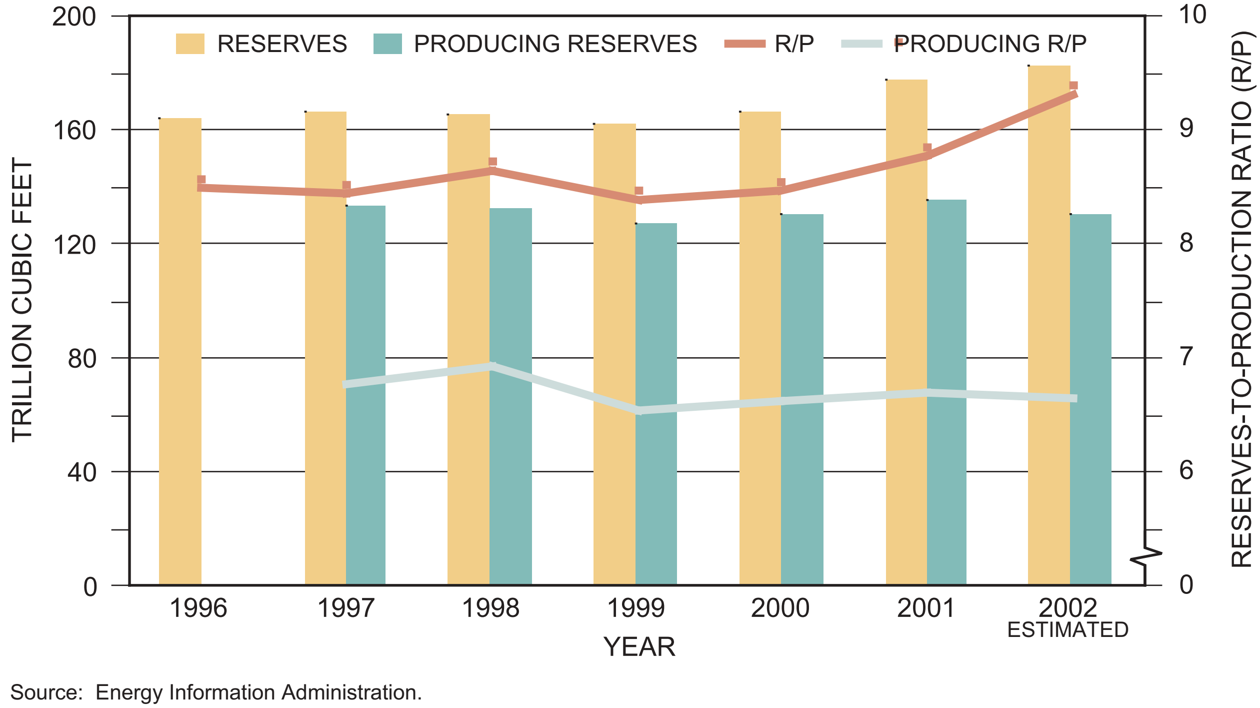


Figure S4-27. U.S. Lower-48 – Wet Gas Proved Reserves

G. Regional Summaries

In an overall environment of slowing production growth, individual producing regions have their own unique production profiles, as basins have been explored and developed, have matured, and new technologies have been applied to the resource.

	% Change 1996-2001	% of Total in 2001	2001	2000	1999	1998	1997	1996	% of Total in 1996
Rockies	40%	29%	50,741	45,924	40,095	37,442	36,342	37,442	24%
West Coast	14%	2%	3,221	3,425	2,923	2,724	2,817	2,724	2%
Midcontinent	-6%	14%	25,315	25,759	25,519	26,455	26,844	26,455	17%
Eastern U.S./Michigan	4%	7%	12,329	12,341	11,815	11,339	11,912	11,339	7%
E. Texas/N. Louisiana	40%	10%	16,781	14,380	12,808	11,976	11,962	11,976	8%
Eastern Gulf Coast	-14%	6%	9,845	10,094	10,583	11,048	11,501	11,048	7%
Permian Basin	6%	7%	12,093	12,429	11,649	10,663	11,446	10,663	7%
Texas Gulf Coast	11%	9%	16,545	16,530	15,717	15,108	14,858	15,108	10%
Gulf of Mexico	-4%	16%	27,708	27,266	26,497	27,321	28,936	27,321	18%
Total		**100%**	**174,660**	**168,190**	**157,672**	**154,114**	**156,661**	**154,114**	**100%**

Source: Energy Information Administration.

Table S4-4. Lower-48 Proved Reserves (Billion Cubic Feet)

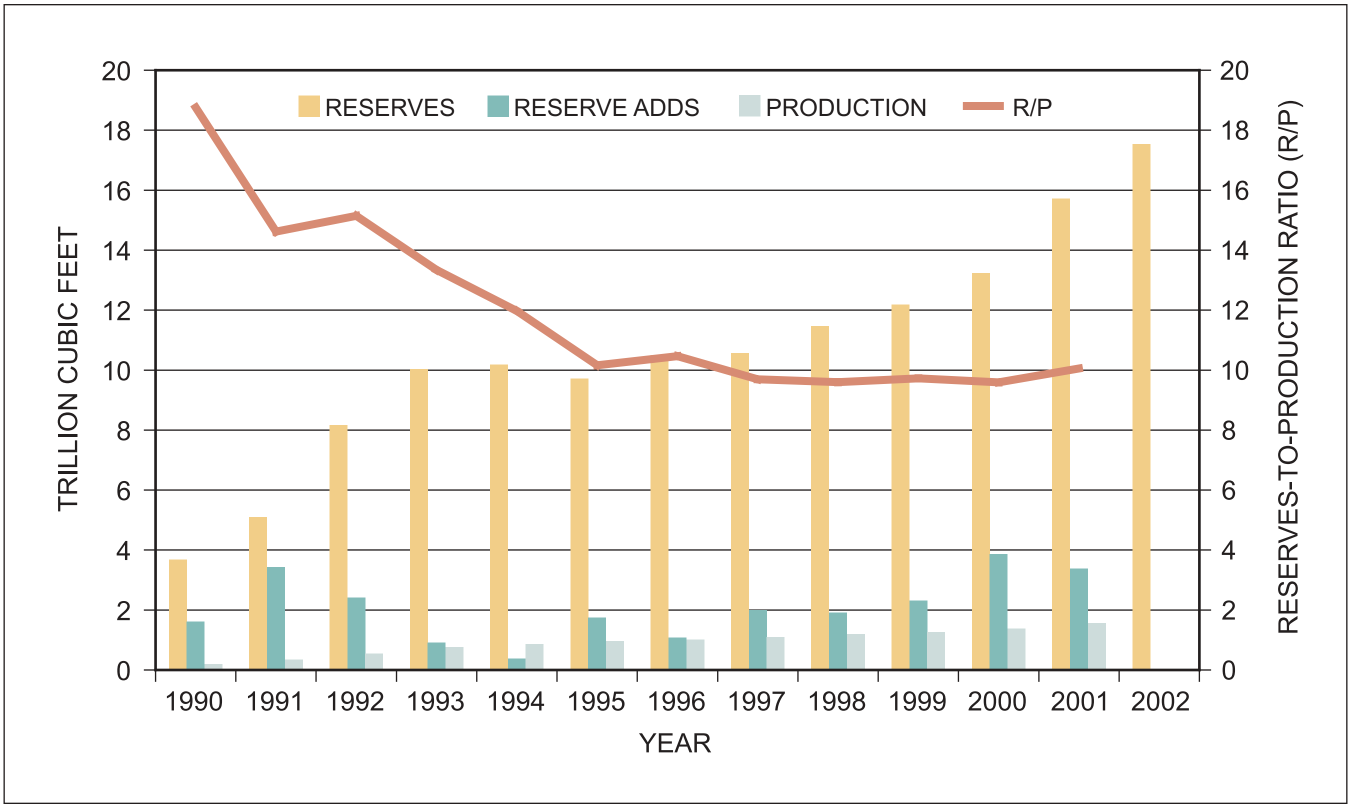


Figure S4-28. U.S. Coal Bed Methane Reserves, Reserve Additions, and R/P

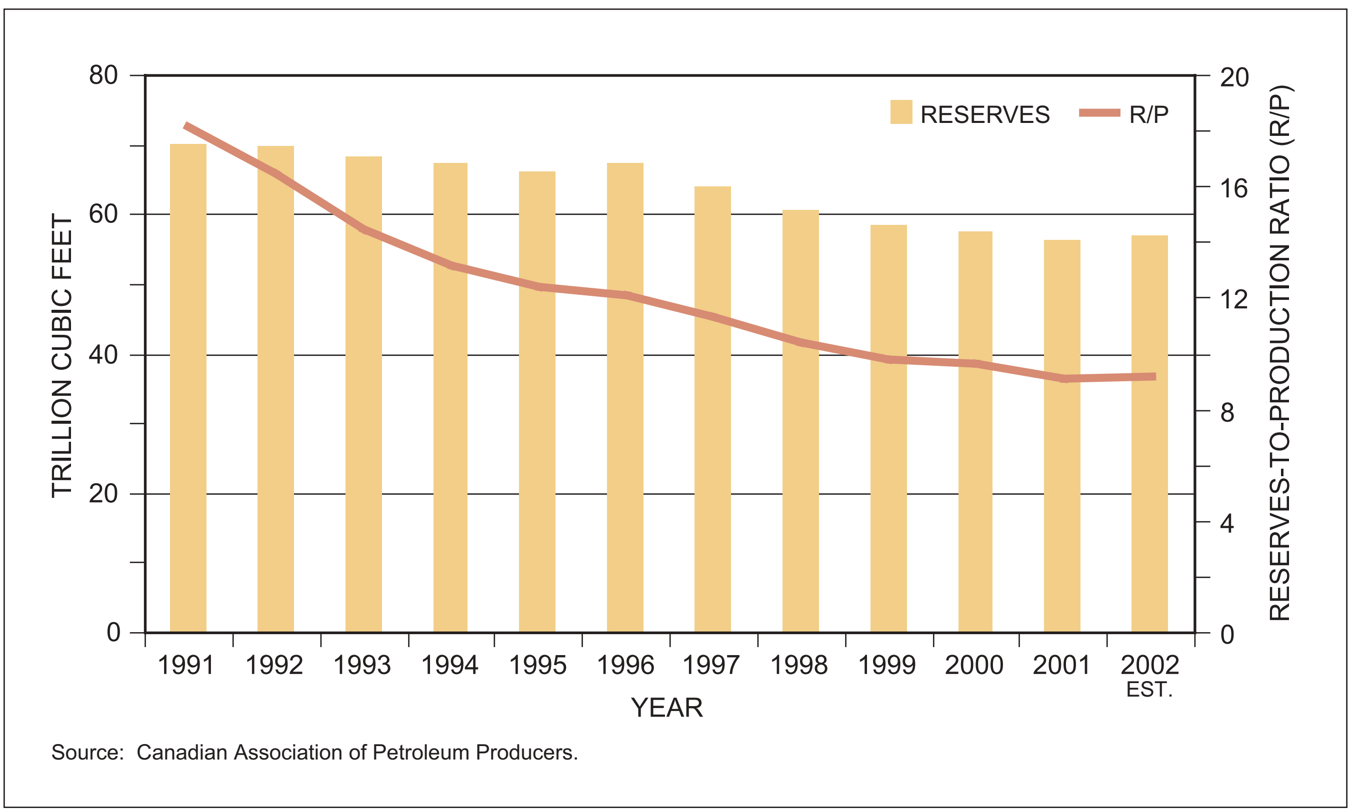


Figure S4-29. Western Canada Sedimentary Basin Proved Reserves

In the frontier areas of the U.S. lower-48 and Canada, technological advances and infrastructure connections have opened up less mature opportunities. Frontier production from the Rockies and Deepwater Gulf of Mexico has grown from 5.0 BCF/D in 1990 to 14.2 BCF/D in 2002.

In the more mature regions of the GOM Shelf and the mature onshore areas of the U.S. lower-48, the industry was able to maintain overall flat production levels in the early part of the decade. After 1996, as these areas continued to mature, they began a sustained decline in production, only slowed by the big drilling ramp-up in the 2000-2001 time frame. (See Figure S4-30.)

1. Declining Basins

- Gulf of Mexico Shelf – The GOM Shelf began the 1990s as the largest producing region in North

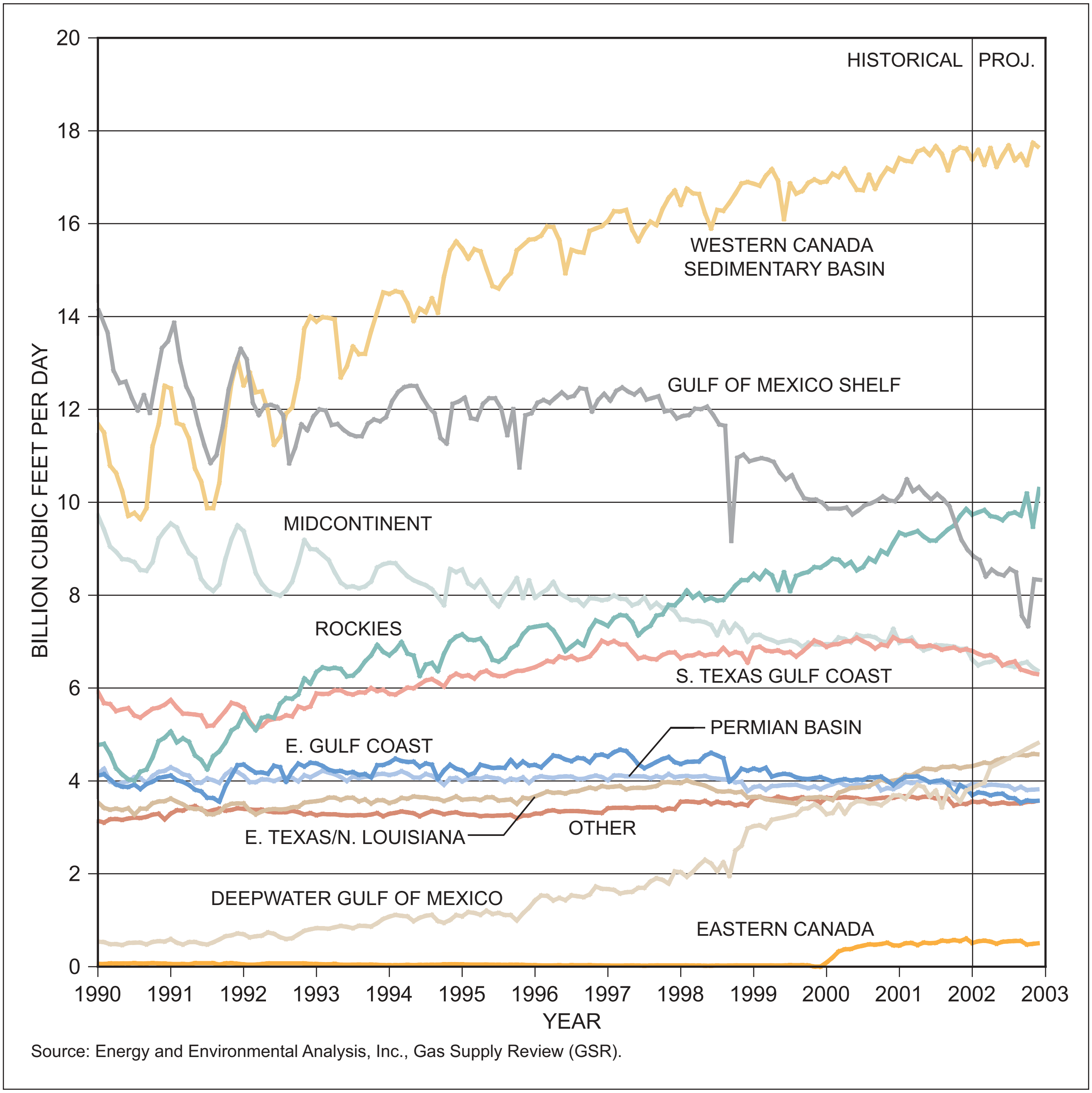


Figure S4-30. North American Gas Production by Region

America, with peak production rates of 14 BCF/D. While Shelf production held fairly steady in the mid-1990s, post 1996 the Shelf began declining at a rate of almost 1 BCF/D per year as new drilling could not keep up with the rapidly declining EURs and steep decline rates as the shallow, 3-D driven "bright spot" play rapidly matured. (See Figure S4-31.) While the drilling ramp-up of 2000-2001 flattened the decline on the Shelf, the Shelf appears to have resumed its rapid decline as drilling rates fell and remained at depressed levels in the later part of 2001 to the current time. By the end of 2002, the Shelf was only the third largest producing region in North America, behind the Western Canada Sedimentary Basin and the Rocky Mountains. The industry has recently begun to explore and develop deeper prospects on the Shelf, which if successful could help flatten future production losses. (See Figure S4-32.)

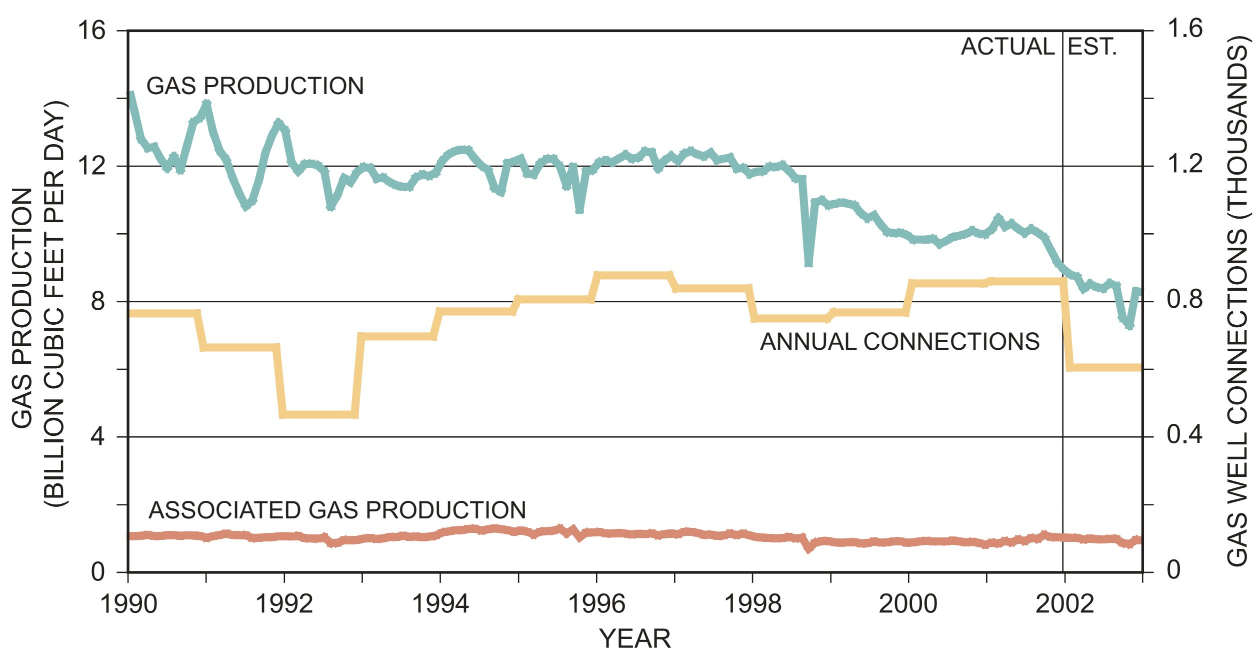
- Eastern Gulf Coast – After rising marginally in the early 1990s, the Eastern Gulf Coast has been on decline since about 1996, with peak production falling over 1 BCF/D to current from a peak of 4.7 BCF/D in 1996 to 3.5 BCF/D at the end of 2002. (See Figure S4-33.)

- Midcontinent – The Midcontinent region started the decade as the 3rd largest producing region in North America (2nd in U.S. lower-48) at peak rates of 10 BCF/D. Production has steadily fallen to less than 6.5 BCF/D currently as EUR has steadily declined throughout the period. (See Figures S4-34, S4-35, and S4-36.)

- Permian Basin – Peak gas production in the Permian Basin has slowly dropped from 4.3 BCF/D in 1990 to the current production level of approximately 3.8 BCF/D. (See Figure S4-37.)

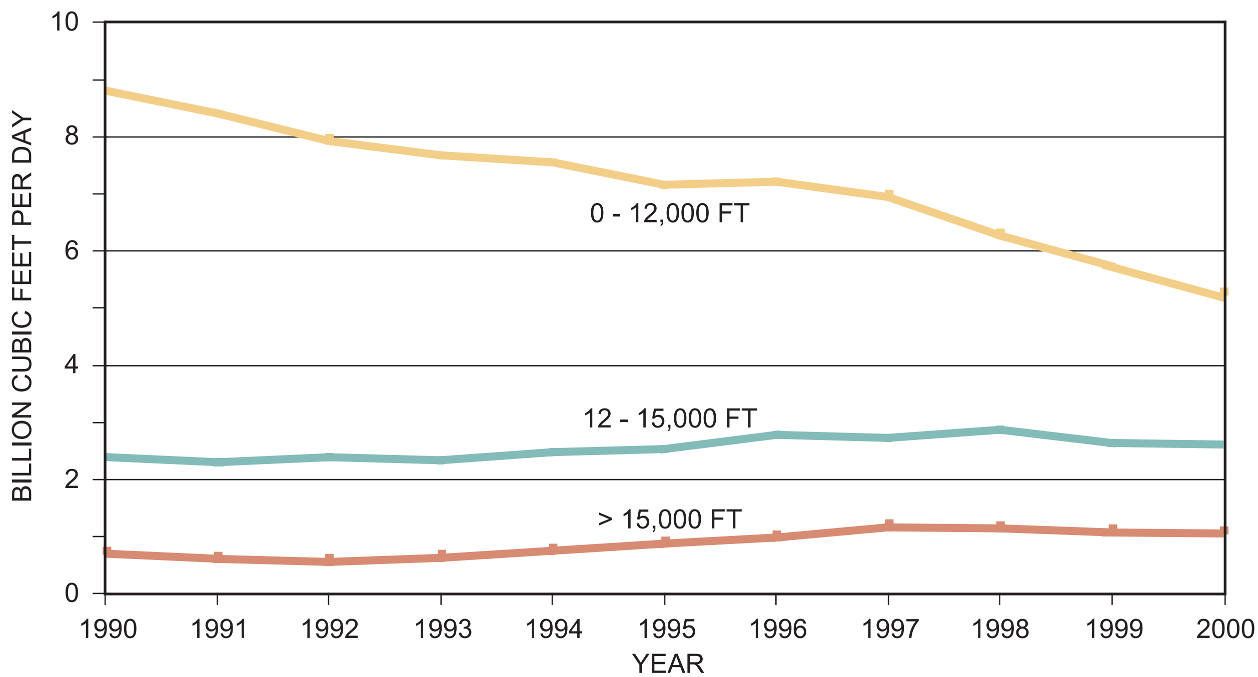
2. Holding Steady/Slight Increase

- South Texas Gulf Coast – Drilling throughout the early-mid part of the 1990s was able to increase production from a peak rate of 5.8 BCF/D in 1990 to 7.1 BCF/D in 2001, an increase of 1.3 BCF/D as regional 3-D seismic coverage allowed deeper prospects and smaller, shallow prospects to be more accurately imaged and exploited. As the basin matured, growth slowed in the later part of the 1990s. Production declined to 6.3 BCF/D by the end of 2002, down almost 1 BCF/D from its maximum. (See Figure S4-38.)



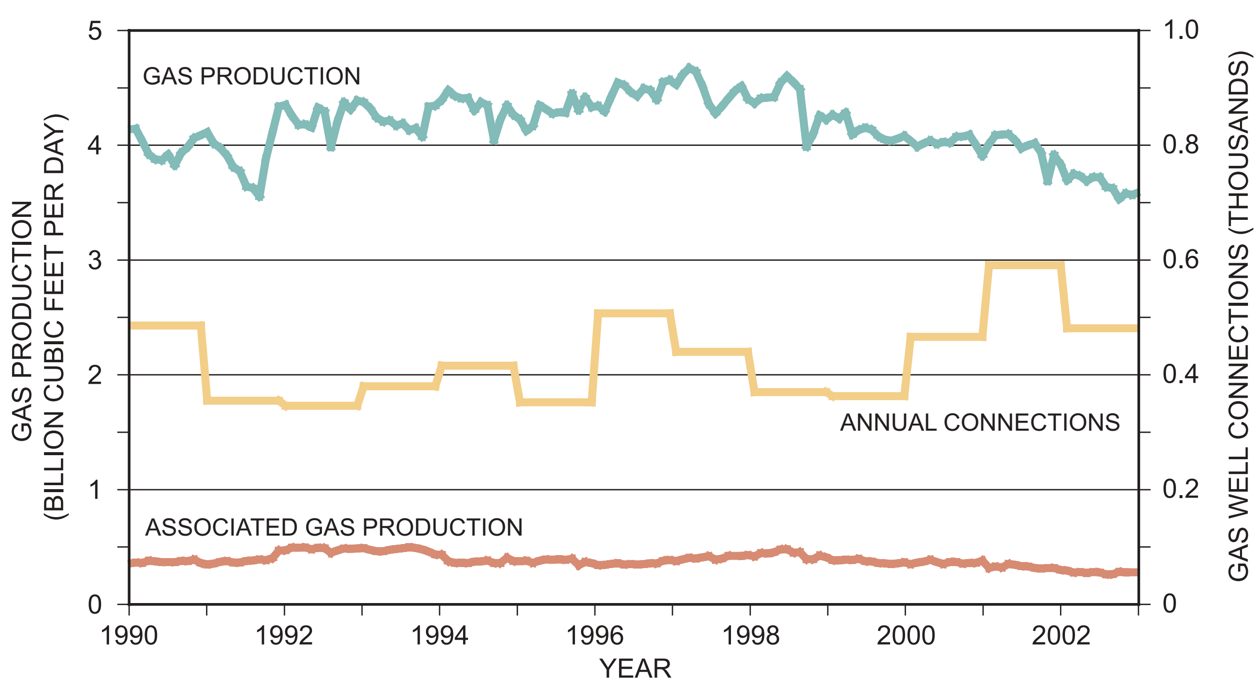
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-31. Gulf of Mexico Shelf – Production and Gas Well Connections



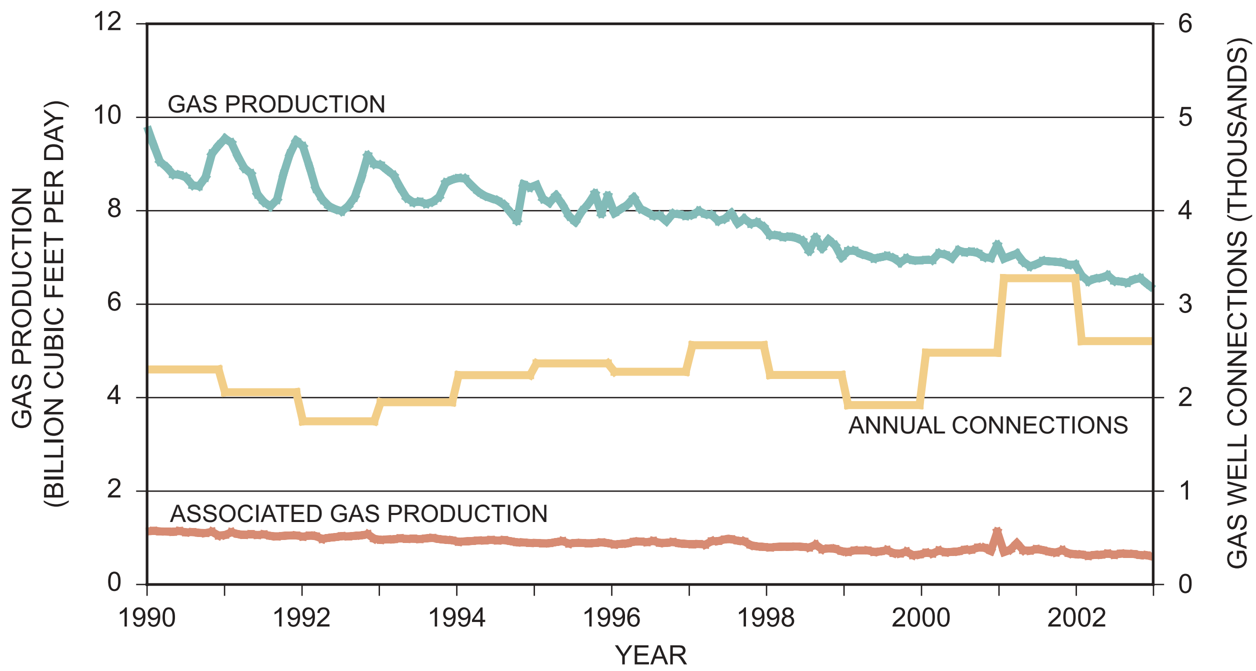
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-32. Gulf of Mexico Shelf – Production by Depth



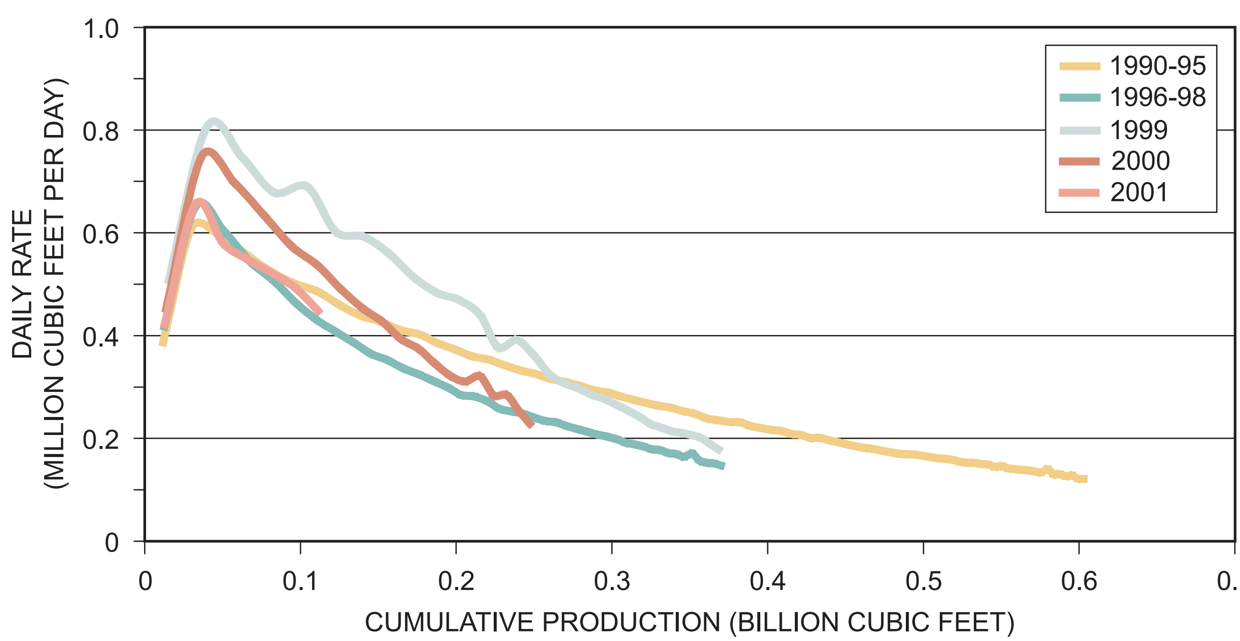
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-33. Eastern Gulf Coast – Production and Gas Well Connections



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-34. Midcontinent – Production and Gas Well Connections



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-35. Anadarko Basin – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production

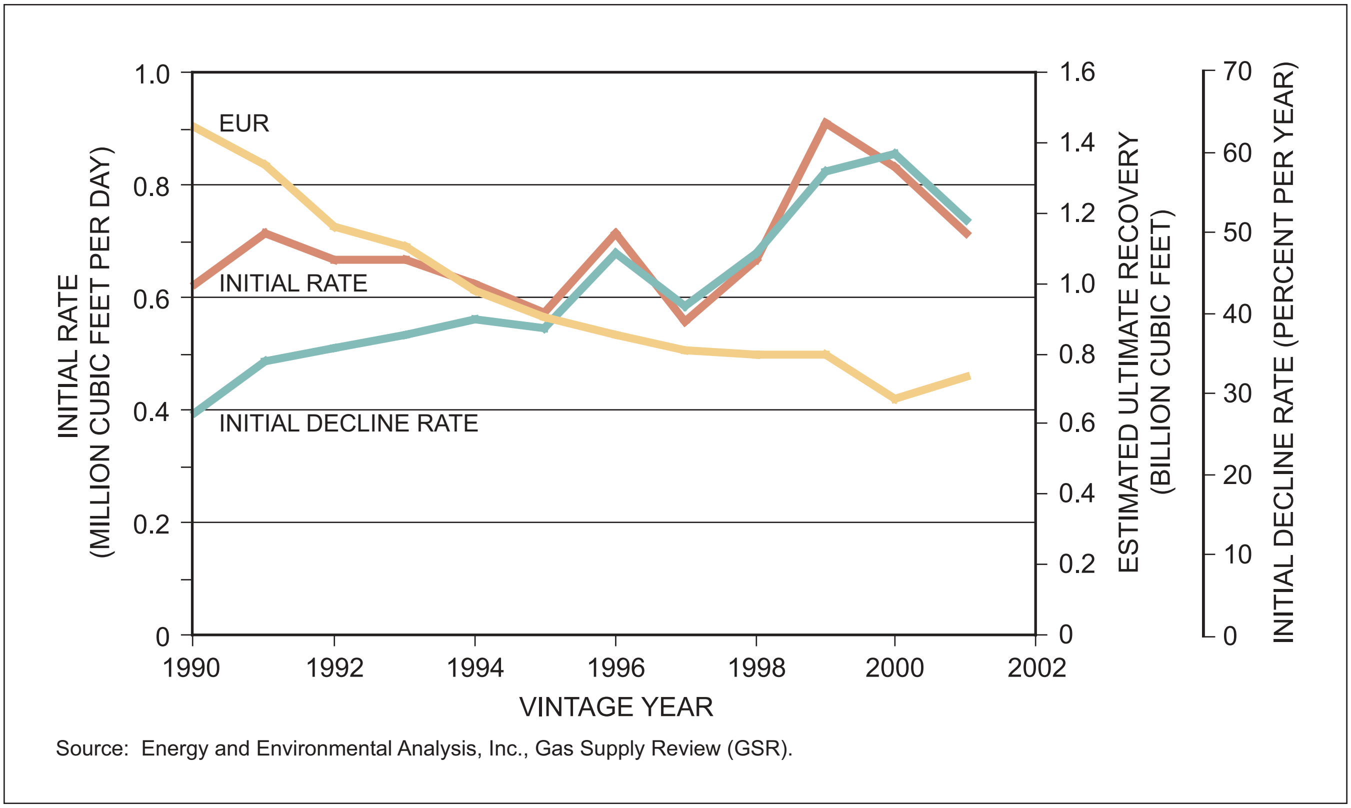


Figure S4-36. Anadarko Basin – Production Performance Trends

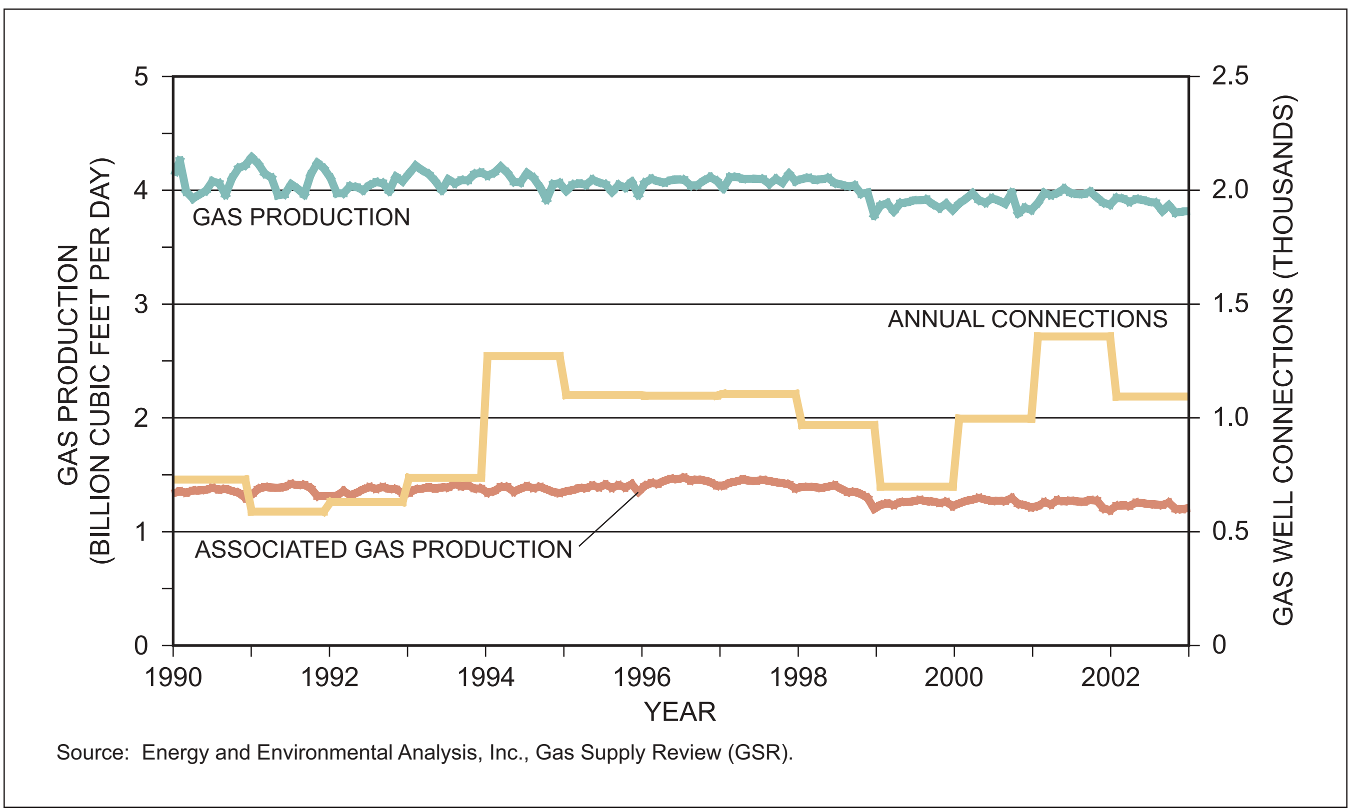


Figure S4-37. Permian Basin – Production and Gas Well Connections

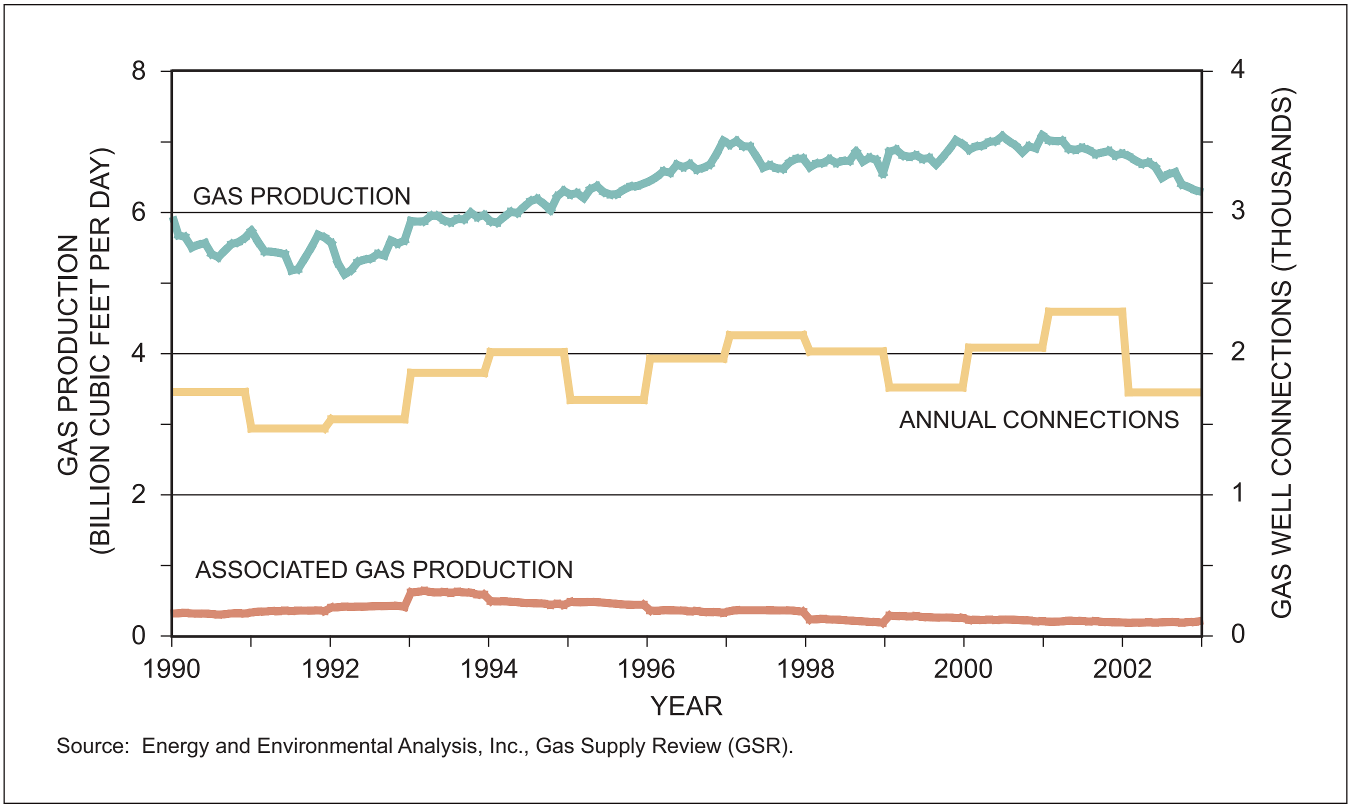


Figure S4-38. South Texas Gulf Coast – Production and Gas Well Connections

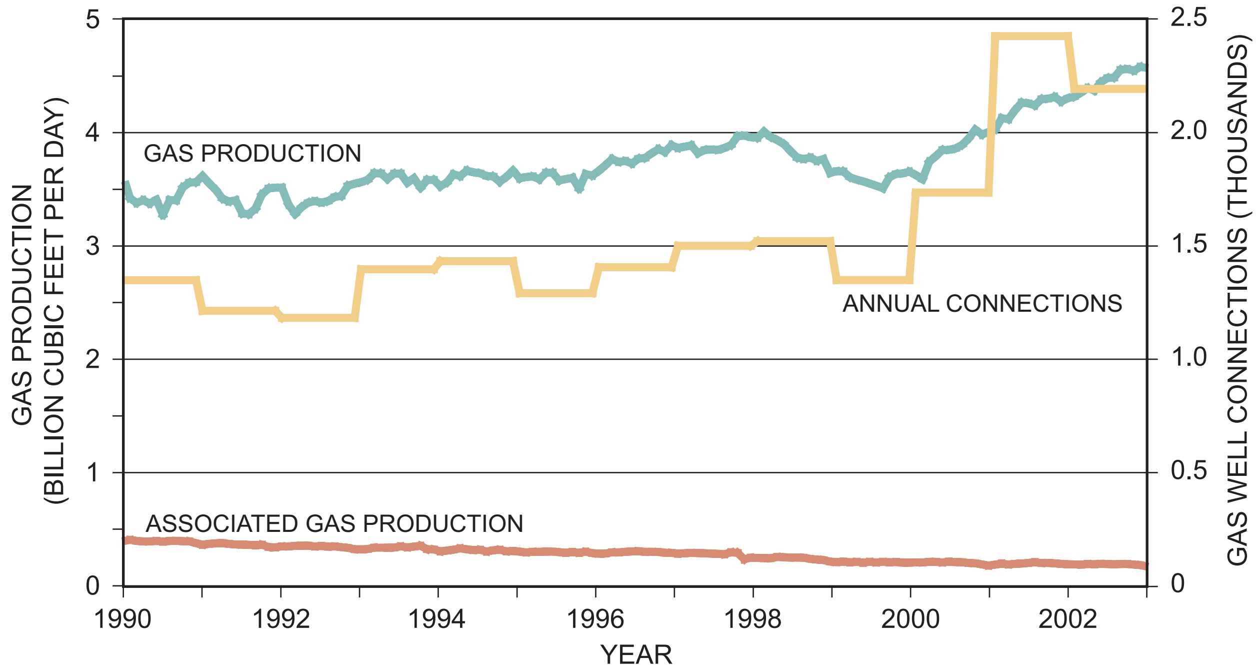
- East Texas/North Louisiana – After holding steady throughout much of the 1990s, production has grown recently over 1 BCF/D, from 3.5 BCF/D in 1999 to 4.6 BCF/D at the end of 2002 as nonconventional tight sands of the Cotton Valley Formation and shales of the Barnett Shale were exploited using applied fracture stimulation technology. While drilling has ramped up substantially, average well productivity has held generally flat and producers have generated sustained production increases. (See Figures S4-39, S4-40, and S4-41.)

3. Increasing Production

- Western Canada Sedimentary Basin – As gas export infrastructure was expanded in the early 1990s, exploration and development interest picked up rapidly in this (at the time) less mature region. The Western Canada Sedimentary Basin has grown to be the largest producing region in North America. While the basin grew strongly in the early 1990s, growth has slowed considerably as the basin rapidly matured. Average well productivity has fallen dramatically and basin decline rates have steepened. 2002 was the first year of flat to declining production in Western Canada in recent history. (See Figures S4-42 and S4-43.)

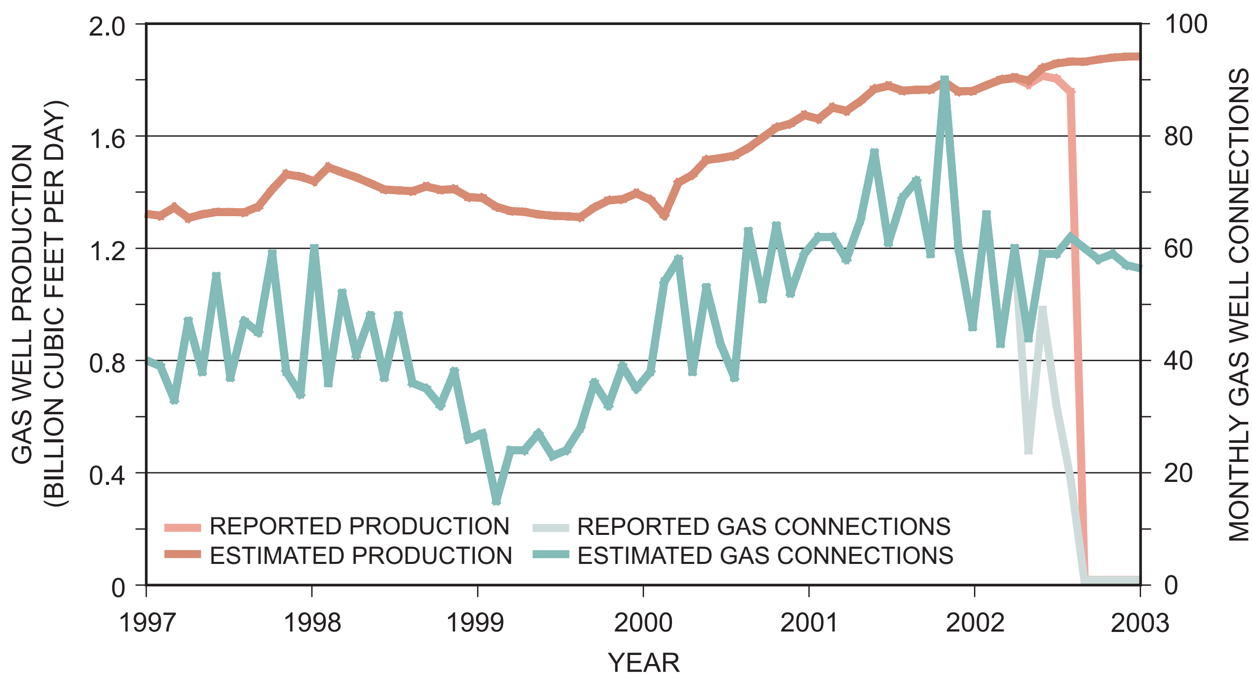
- Rocky Mountains (including the San Juan Basin) – Production from the Rocky Mountains has grown steadily throughout the decade, even with periods of low regional prices, and the Rockies are currently the 2nd largest producing region in North America (1st in U.S. lower-48). While much of the Rockies growth has come from nonconventional resources (coal bed methane, tight gas), both conventional and nonconventional production rates have been increasing. (See Figure S4-44.)

- Deepwater Gulf of Mexico – 3-D seismic technology and advancing development/production technology has opened this frontier area to drilling. While primarily an oil play, gas production has grown strongly as new developments and infrastructure have been built out. While Shelf production has been falling rapidly, increased Deepwater production has been able, until recently, to sustain total GOM production at approximately 14 BCF/D. (See Figure S4-45.)



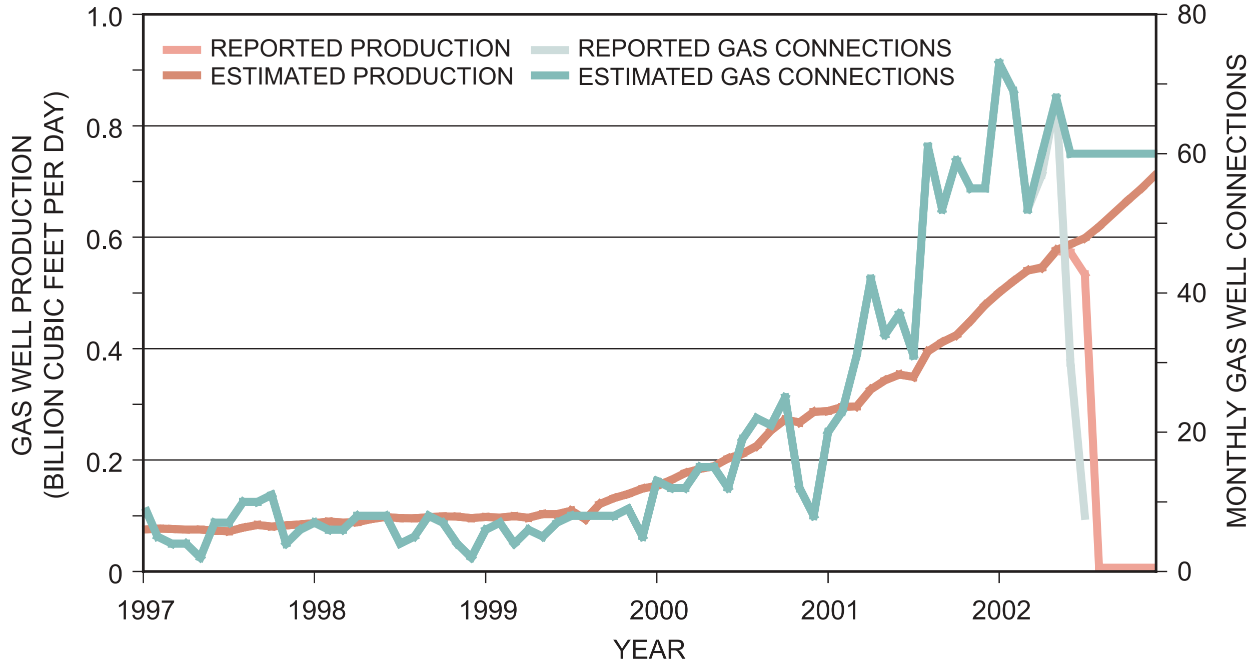
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-39. East Texas/North Louisiana – Production and Gas Well Connections



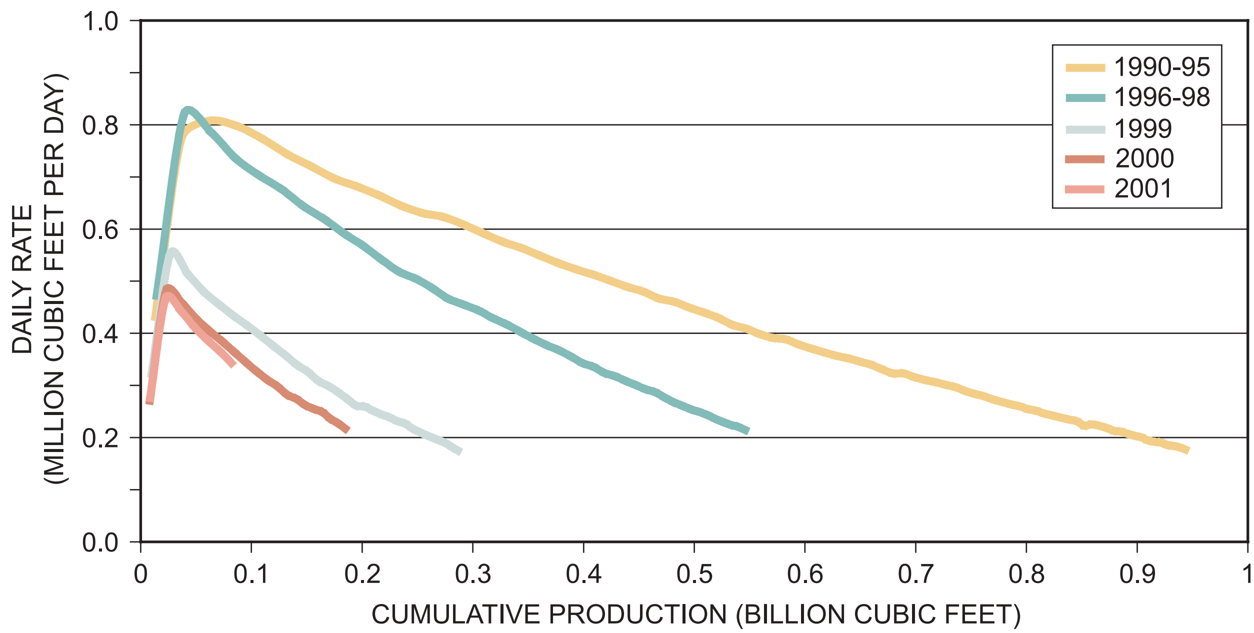
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-40. Cotton Valley Formation – Production and Gas Well Connections



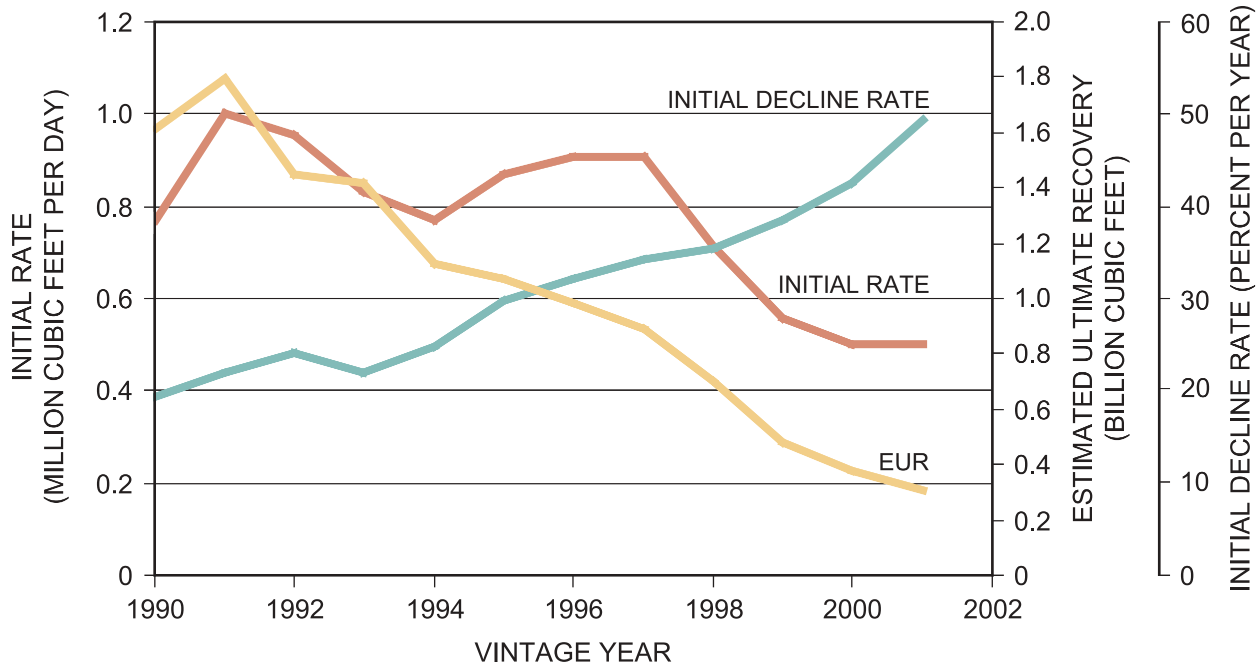
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-41. Barnett Shale – Production and Gas Well Connections



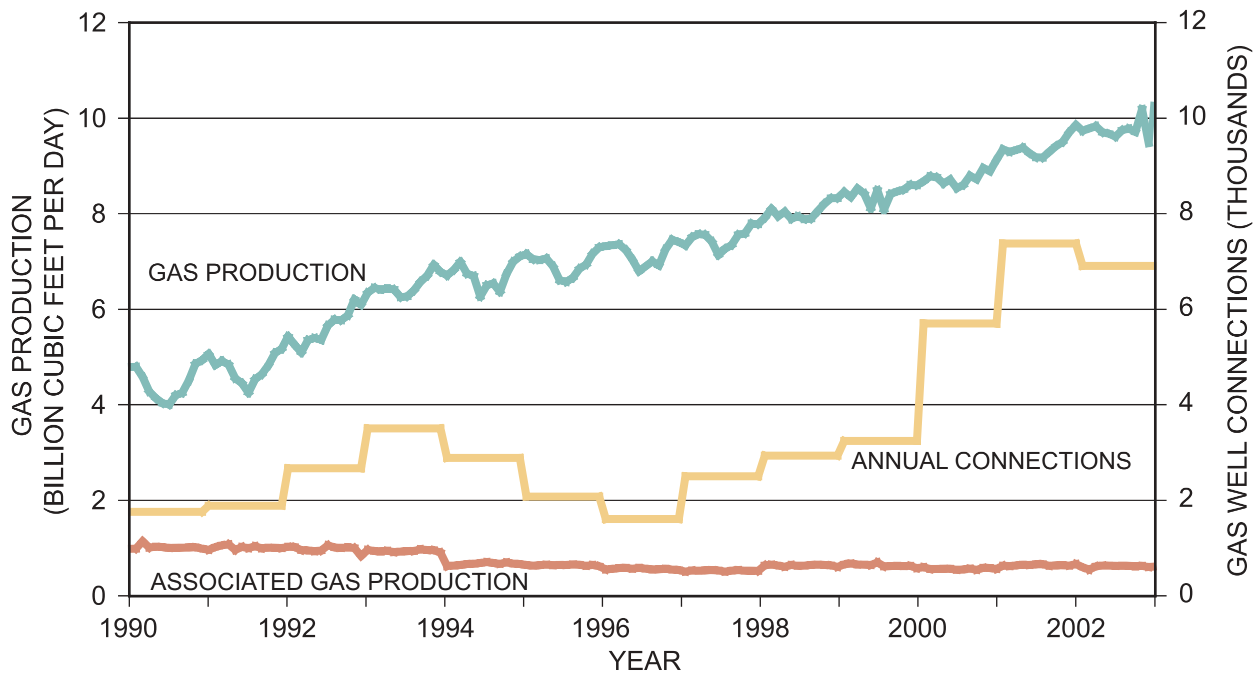
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-42. Western Canada Sedimentary Basin – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-43. Western Canada Sedimentary Basin – Production Performance Trends



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-44. Rocky Mountains – Production and Gas Well Connections

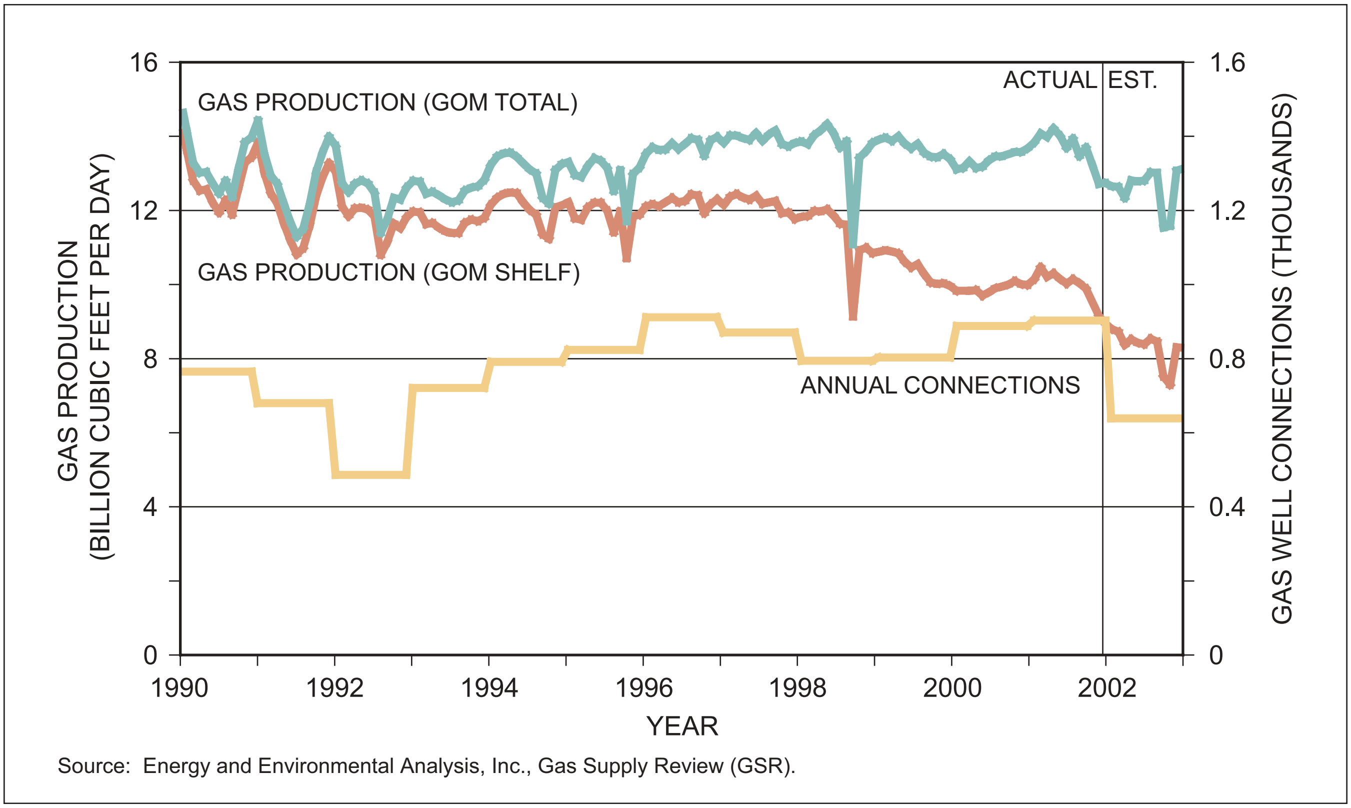


Figure S4-45. Gulf of Mexico – Production and Gas Well Connections

Future production growth will depend largely on whether the industry can sustain the recent pace of adding proved reserves and developing large fields, which typically require high-cost, long lead-time projects. The pace of development will also be more dependent on oil-price driven economics than natural gas economics. (See Figure S4-46.)

H. 2000-2001 Drilling

The 2000-2001 drilling campaign saw the industry ramp up gas rig activity from a low of 400 rigs in 1999 to over 1050 rigs in 2001, utilizing essentially 100% of rig capacity. This was almost double the peak rig rate in the 1997-1998 drilling ramp-up but the production response was fairly similar, up approximately 2 BCF/D. When drilling slowed to average 700 rigs in 2002, above the peak drilling rates in 1997-98, production fell dramatically, rather than rising. What was the difference?

1. The resource base has continued to mature – average well EUR has been on a long-term decline and the drilling campaign of 2000 and 2001 only accelerated the trend.
2. Marginal drilling was characterized by very low productivity wells. In terms of first year build-up, the onshore basins with the exception of East Texas showed average first year build-up falling 15% to 25%. (See Figure S4-47.)
3. The majority of gas completions occurred in low rate, high R/P areas such as the Powder River Basin coal bed methane wells.

   Figures S4-48, S4-49, and S4-50 detail, by basin, the “incremental connections” – i.e., the new gas connections in 2001 versus gas connections in 1999. The Powder River Basin showed the largest increase at 2,475 incremental connections. The next plot shows the average rate per connection, calculated as the average rate for 2001 connections over the first 12 months of production. Powder River Basin wells averaged only 0.065 MMCF/D versus 4.2 MMCF/D for the more prolific GOM wells. Multiplying incremental wells by average rate yields build-up. Despite the high drilling activity, Powder River Basin wells only contributed 160 MMCF/D of build-up.
4. While technology had allowed industry to sustain production at lower activity levels in the mid-1990s

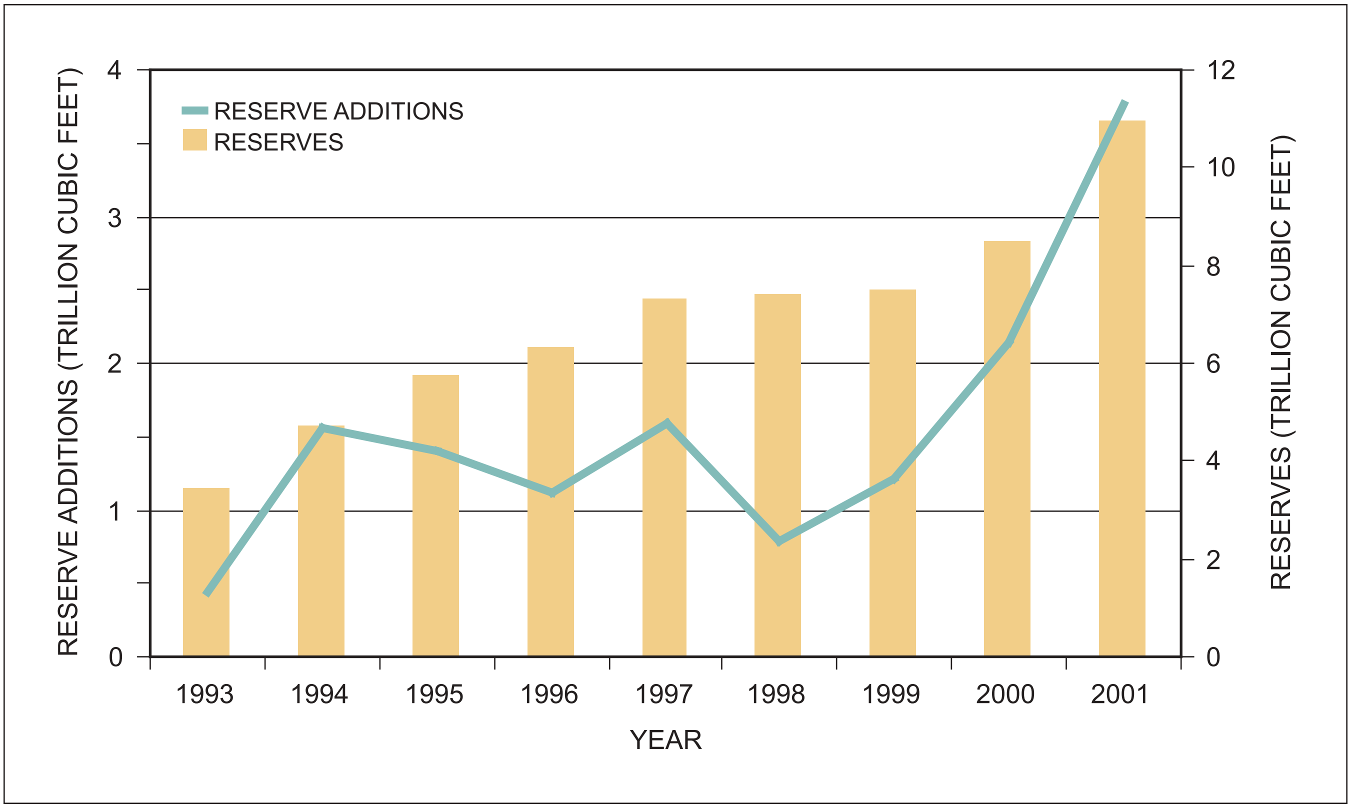


Figure S4-46. Gulf of Mexico Deepwater – Reserves and Annual Reserve Additions

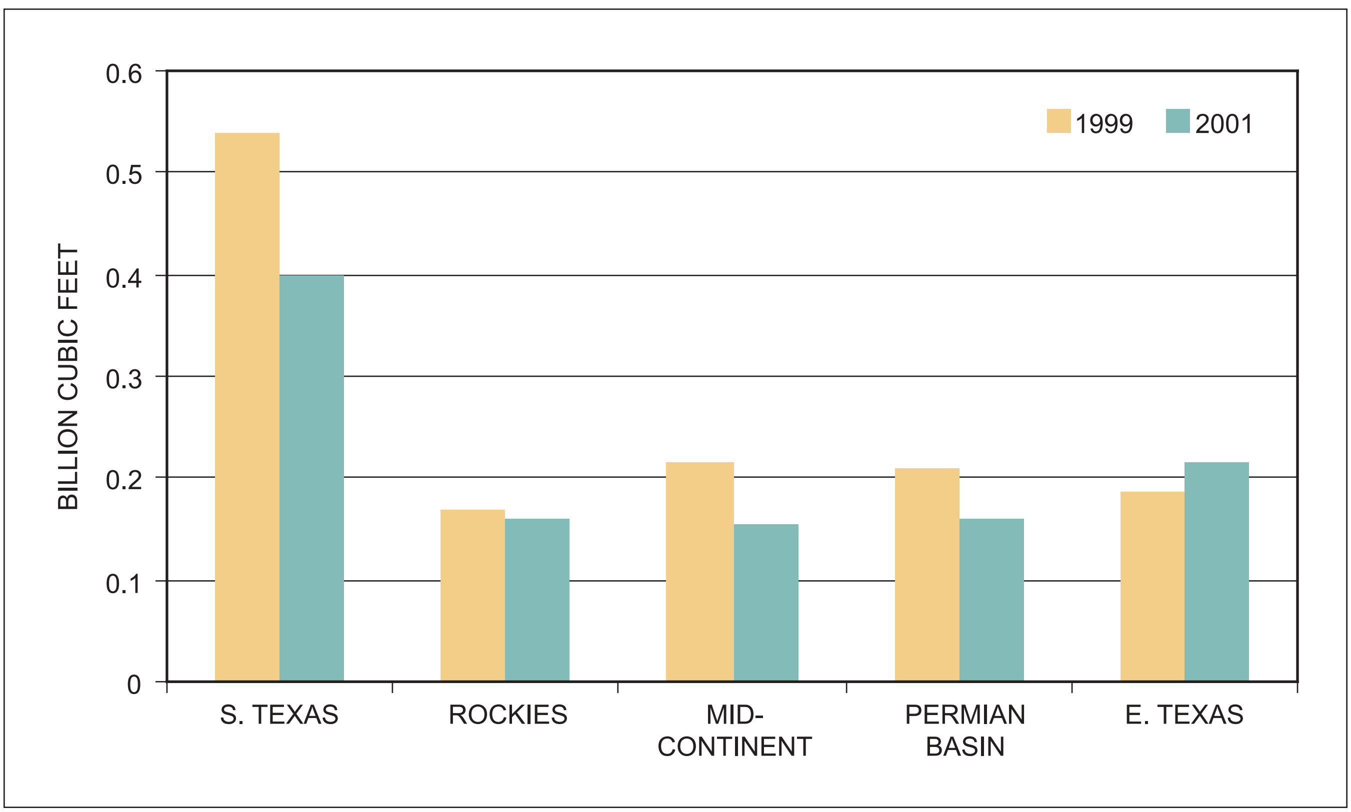


Figure S4-47. First Year Deliverability

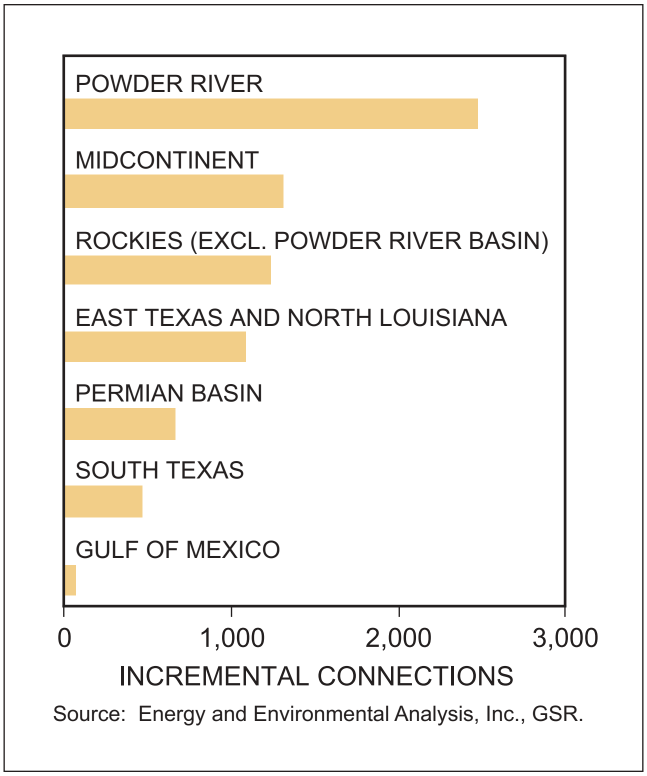


Figure S4-48. Incremental Drilling by Region – 2001 vs. 1999

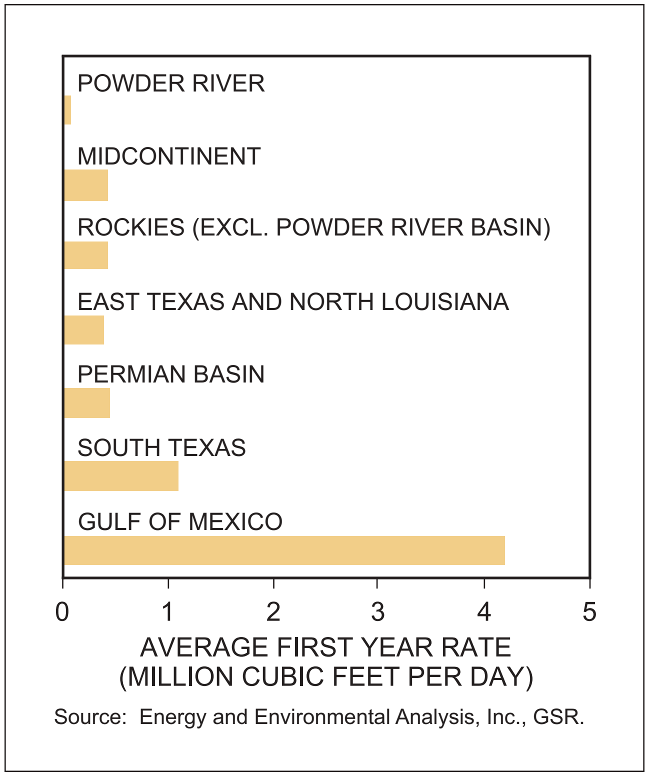


Figure S4-49. First Year Well Production by Region

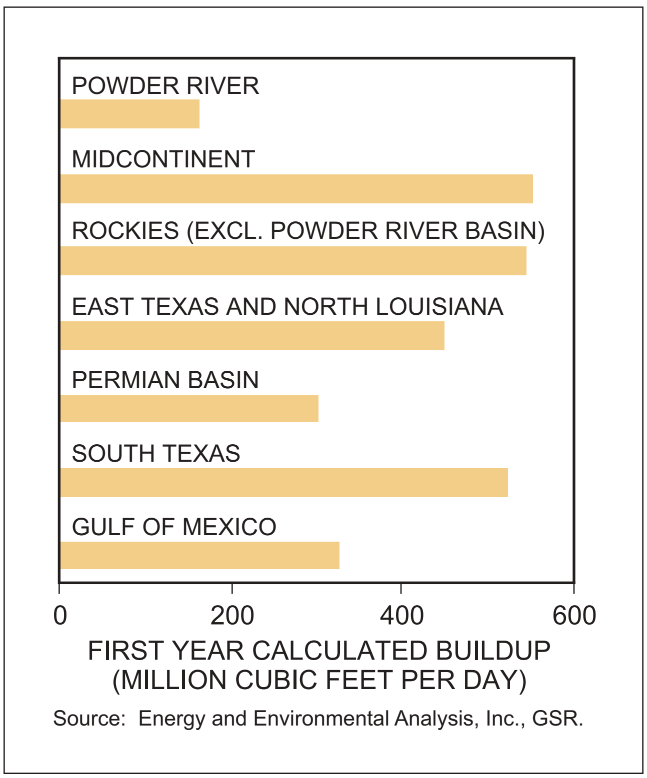


Figure S4-50. Incremental Drilling Buildup by Region – 2001 vs. 1999

by accelerating well production, these technologies had largely matured and reached saturation.

5. As individual well production was accelerated, base declines steepened over the period. It took 8 BCF/D of new production to replace base declines in the early part of the 1990s. That had increased by over 50% to almost 13 BCF/D.

6. Higher gas prices made it possible to drill lower quality prospects.

7. As rig activity ramped up, rig efficiency fell as measured in completions per rig-year and footage per rig-year.

I. Model Calibration

Production performance parameters generated in this analysis were either utilized as direct inputs to the HSM model, or were used to reality check HSM outputs. For example, the production profile of the HSM model's Proved Reserve base was modeled using the actual decline of pre-1998 completions. As historical individual gas well performance parameters were generated for each region, depth interval, and production type, they were checked against conventional decline analysis and utilized to provide a reality check of future well performance parameters.

II. Basin Summaries

A. Gulf of Mexico Shelf

1. Historical Performance

The GOM Shelf has been a very significant component of the lower-48 natural gas supply over more than the past 20 years. In the early 1990s, the Shelf was the largest gas-producing region in North America. After producing 13 BCF/D in the early 1990s, Shelf production averaged 12 BCF/D through 1997 and then began to decline. At the end of 2002, production from the Shelf was estimated at just over 8 BCF/D. (See Figure S4-51.)

The GOM Shelf average annual gas rig count has varied from 40 to 138 since 1990. Since 1997, the Shelf gas well rig count has averaged well over 100 rigs. During that time, the GOM Shelf production has dropped by 4 BCF/D. The lack of correlation between basin production and the rig count reveals the increasing maturity of the region.

In the late 1980s, the advent of 3-D seismic coverage of the Shelf led to the delineation of numerous shallow "bright spot" gas targets. A seismic "bright spot" occurs as a result of low density natural gas being stored in the reservoir rock pores. These targets were easy to define in terms of area, thickness and reserves. By the mid-1990s, most of these low risk shallower targets, generally less than 12,000', had been drilled.

In an attempt to halt the GOM Shelf production decline, operators are beginning to target deeper, higher risk accumulations in the mostly unexplored deep sediment. The current drilling activity is targeting deeper horizons that do not necessarily have bright spots or other HCIs (hydrocarbon indicators). This is due to the reduced clarity of seismic data with depth, combined with the lower porosity reservoirs that occur at increased depth. The deeper wells take twice as long to drill and the success rate is significantly less than the shallow "bright spot" play. While there is a significant deep resource to be recovered, it is a fundamentally different play than the shallow "bright spot" play and it will be difficult to arrest the overall Shelf production decline. (See Figure S4-52.)

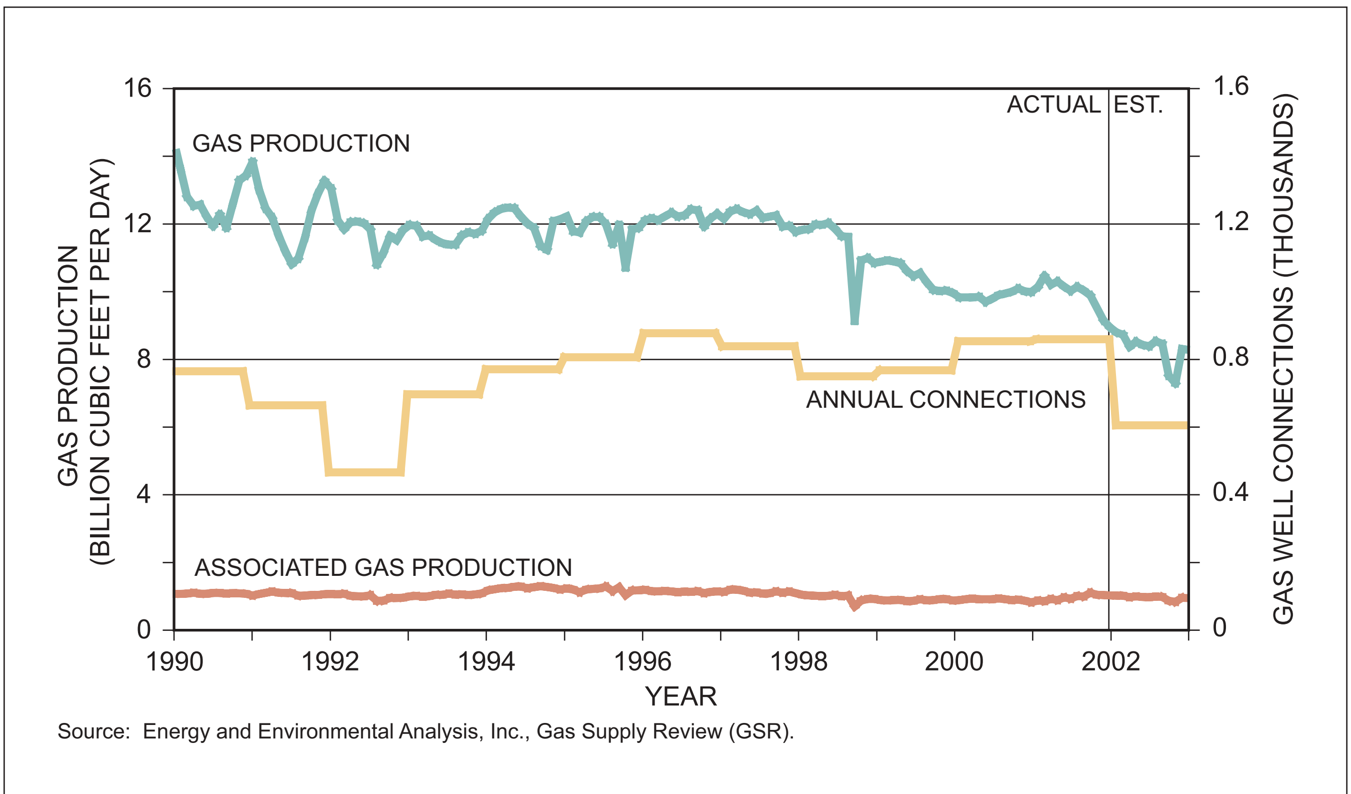


Figure S4-51. Gulf of Mexico Shelf – Production and Gas Well Connections

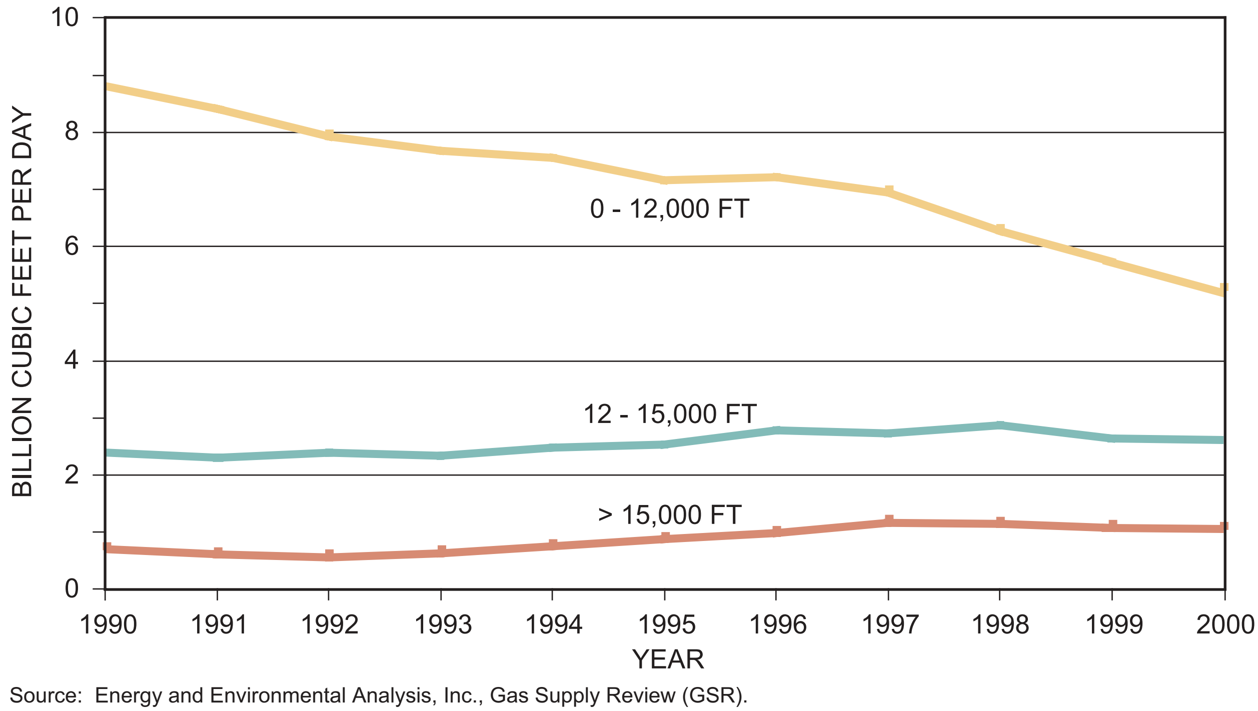


Figure S4-52. Gulf of Mexico Shelf – Production by Depth

2. Well Performance

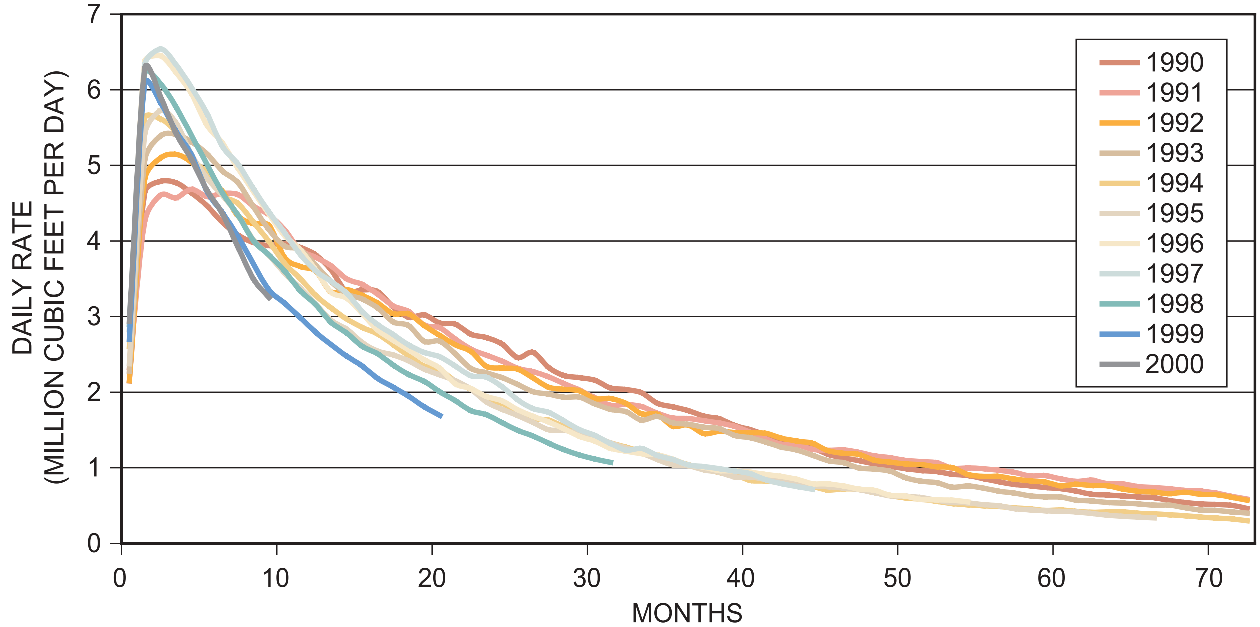
The average GOM Shelf well was analyzed in terms of vintage, area, and depth drilled. The Rate versus Time and Rate vs. Cumulative Production plots indicate that recent completions have slightly lower initial rates versus the mid-1990s. However, the EUR per completion for all areas has fallen by almost 35%. (See Figures S4-53, S4-54, and S4-55.)

The increase in deep production is a result of more advanced drilling and completion techniques, and improved seismic processing methods which lower prospect risk. Specific examples of drilling and completion technology that has helped exploit the deep Shelf include the following:

1. The advent of PDC bits and synthetic oil base mud has greatly increased rate of penetration, which have made well costs more commercial.

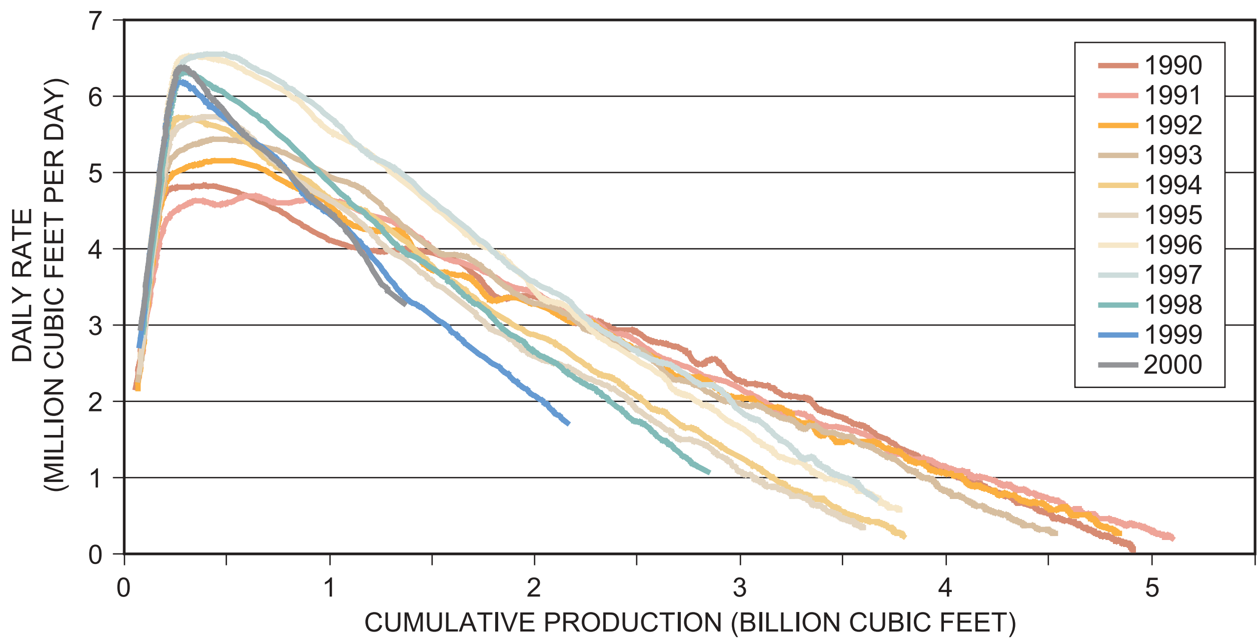
2. Expandable casing is especially important to drilling deep sediments, because it allows for smaller casing sizes to start the well. This lowers the cost and decreases the time it takes to drill the well. The expandable casing is run at a smaller size and placed in the wellbore. Once properly placed, the casing uses a new technology to extrude the casing to a larger size that fits flush against the previous casing string. This allows the next bit size to be bigger and allow for larger production casing to be run once the well has reached total depth. Larger casing sizes can have larger diameter tubing to be installed in the well. The larger the tubing, the higher the production rate of the well.

3. A relatively new offshore completion/stimulation is called the "frac-pac." Since many of the reservoir rocks are not stable and require sand control, screens were installed in the wellbore to prevent the flow of formation sand into the wellbore which could lead to casing failure. The problem with the screens (known as "gravel packs") was that they would produce a large pressure drop which would restrict the flow of hydrocarbon fluids. The "frac-pac" stimulates the reservoir sand with proppant to reduce the pressure drop associated with the installation of the sand control screen. Up to 500,000 pounds of proppant have been pumped offshore to help wells produce at higher rates.



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-53. Gulf of Mexico Shelf – Average Daily Gas Well Production vs. Time, by Year of First Production



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-54. Gulf of Mexico Shelf – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production

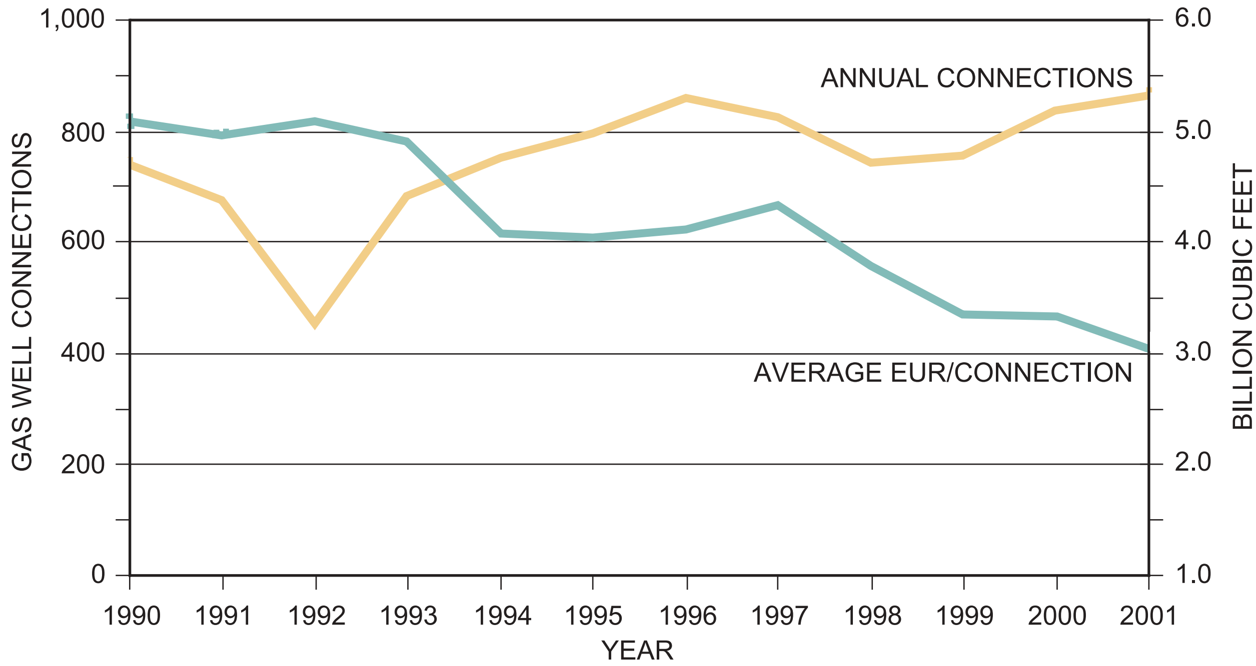


Figure S4-55. Gulf of Mexico Shelf (excluding Norphlet) – Estimated Ultimate Recovery per Gas Connection

4. Improved metallurgy for downhole tools has allowed this technology to be used for ultra-deep completions (>18,000').

5. Seismically, the use of hydro-carbon indicators (HCIs) besides the well known "bright spot" has led to increased exploration success. Pre-stack time migration, pre-stack depth migration, and AVO are all tools that have become readily available to help image deep structures and help locate gas accumulations.

3. Base Decline

Base production declines have steepened on the GOM Shelf, from approximately 30% in the early-1990s to 40% more recently. 2001 and later data has been plagued by reporting delays. As declines have incrementally steepened, even as production levels have dropped on the Shelf, it continues to require 3-3.5 BCF/D on new Shelf production to simply replace decline. (See Figures S4-56 and S4-57.)

4. Reserves

Overall GOM Shelf gas reserves and annual reserve adds have fallen steadily. Reserves totaled over 23 TCF of gas at the end of 1992. That level has fallen to just over 15.5 TCF of gas at the end of 2001, a fall of almost 8 TCF in 9 years, or nearly 1 TCF per year. Annual reserve adds, which were averaging 4-4.5 TCF per year in the early 1990s, have fallen dramatically. (See Figure S4-58.)

B. Gulf of Mexico Deepwater

1. Historical Performance

The Deepwater Gulf of Mexico (DW GOM) has increasingly become a significant component of lower-48 natural gas. Since 1990, when production averaged 0.5 BCF/D, production from the DW GOM has grown steadily. At the end of 2002 production from the DW GOM was estimated at 5 BCF/D, however data delays from the OCS have meant that 2002 is just an estimate. (See Figure S4-59.)

In the mid-1990s, steadily increasing DW GOM production combined with stable Shelf production allowed total GOM production to grow to near 14 BCF/D by 1997. As the Shelf began to decline, more rapidly increasing production from the DW GOM was able to generally flatten the overall GOM decline.

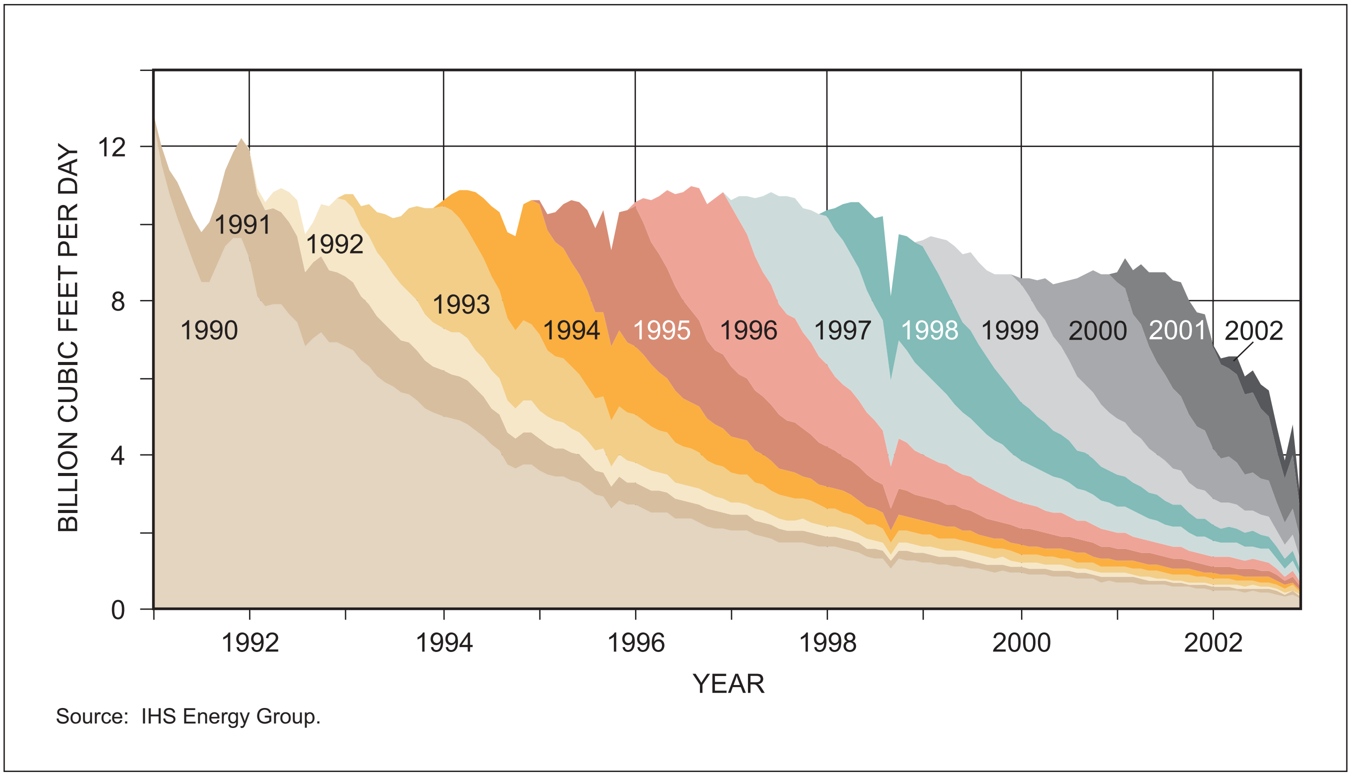


Figure S4-56. Gulf of Mexico Shelf – Daily Wet Gas Production from Gas Wells, by Year of Production Start

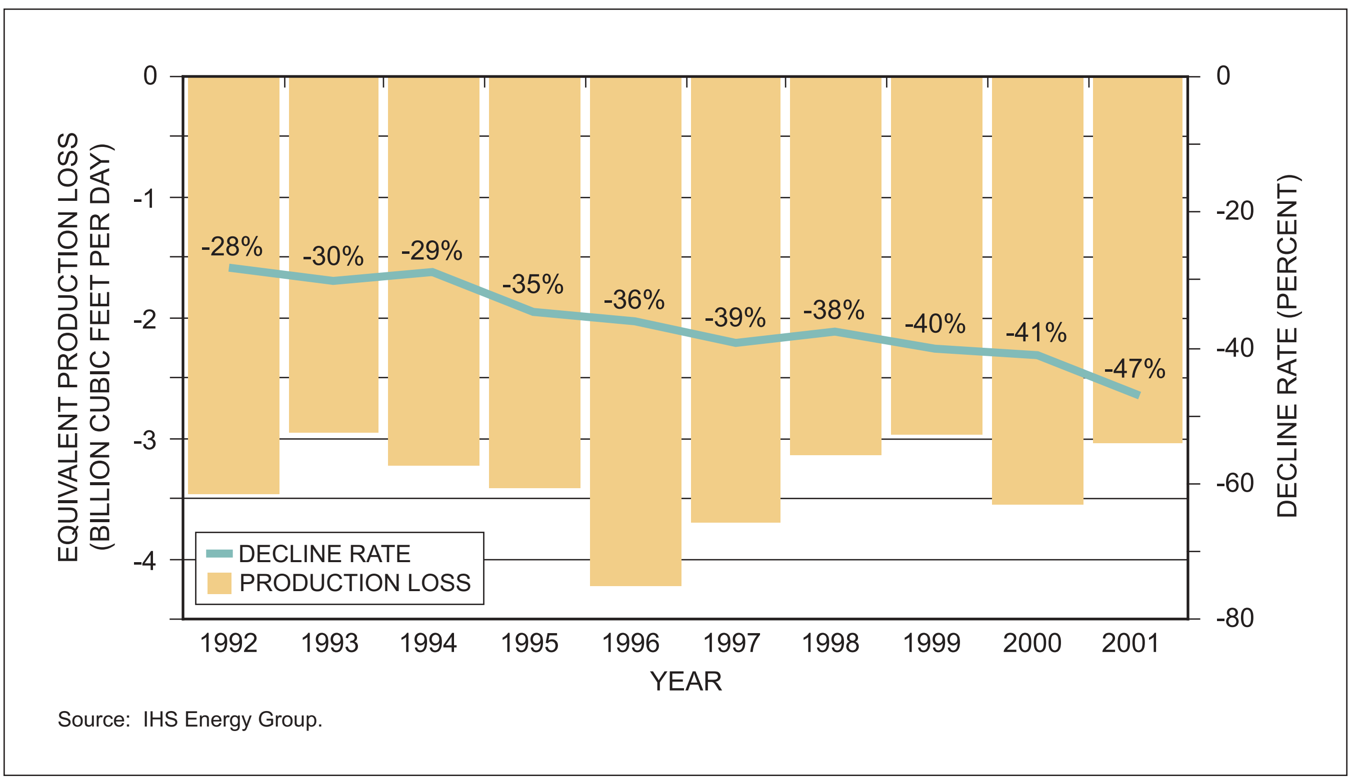


Figure S4-57. Gulf of Mexico Base Shelf – Decline Rate of Base Gas Production if No New Wells had been Drilled, and Equivalent Production Loss

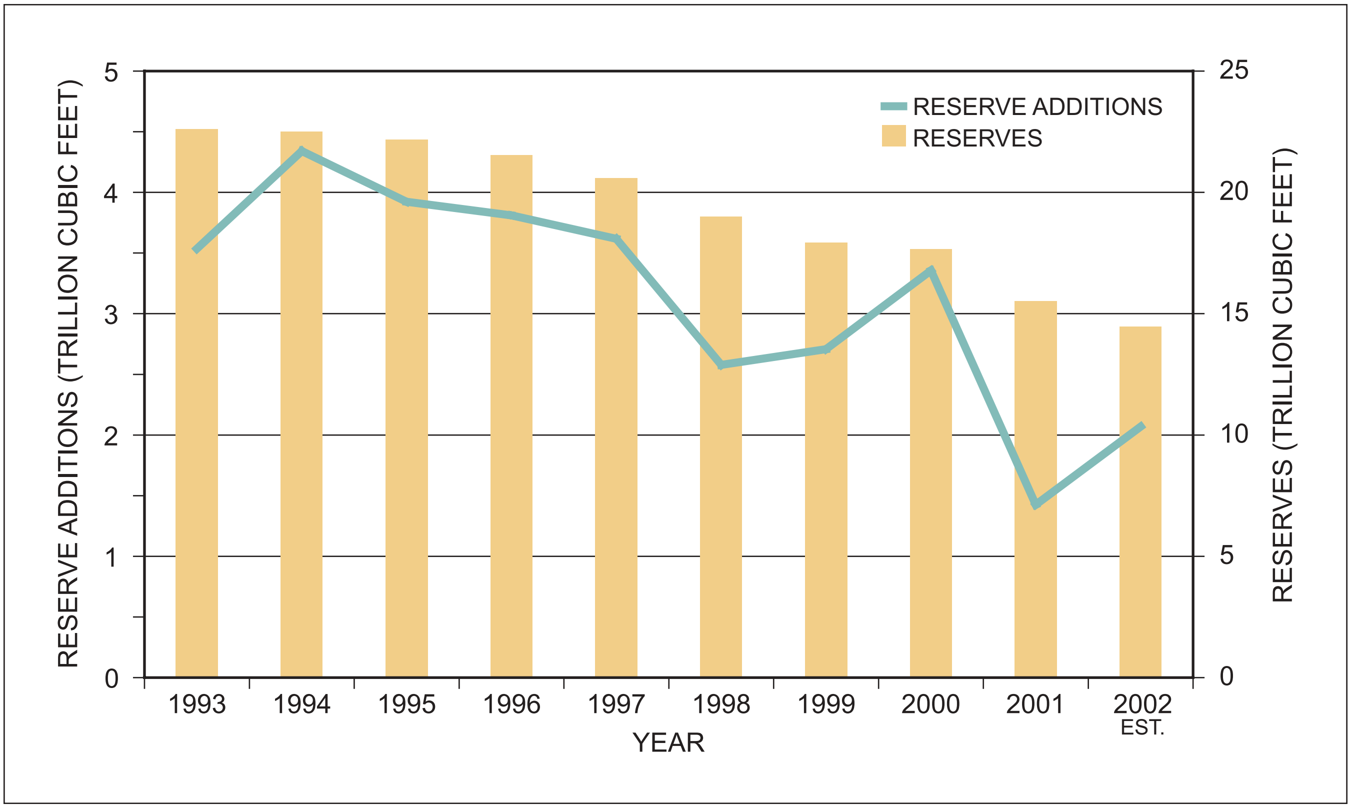


Figure S4-58. Gulf of Mexico Shelf – Reserves and Annual Reserve Additions

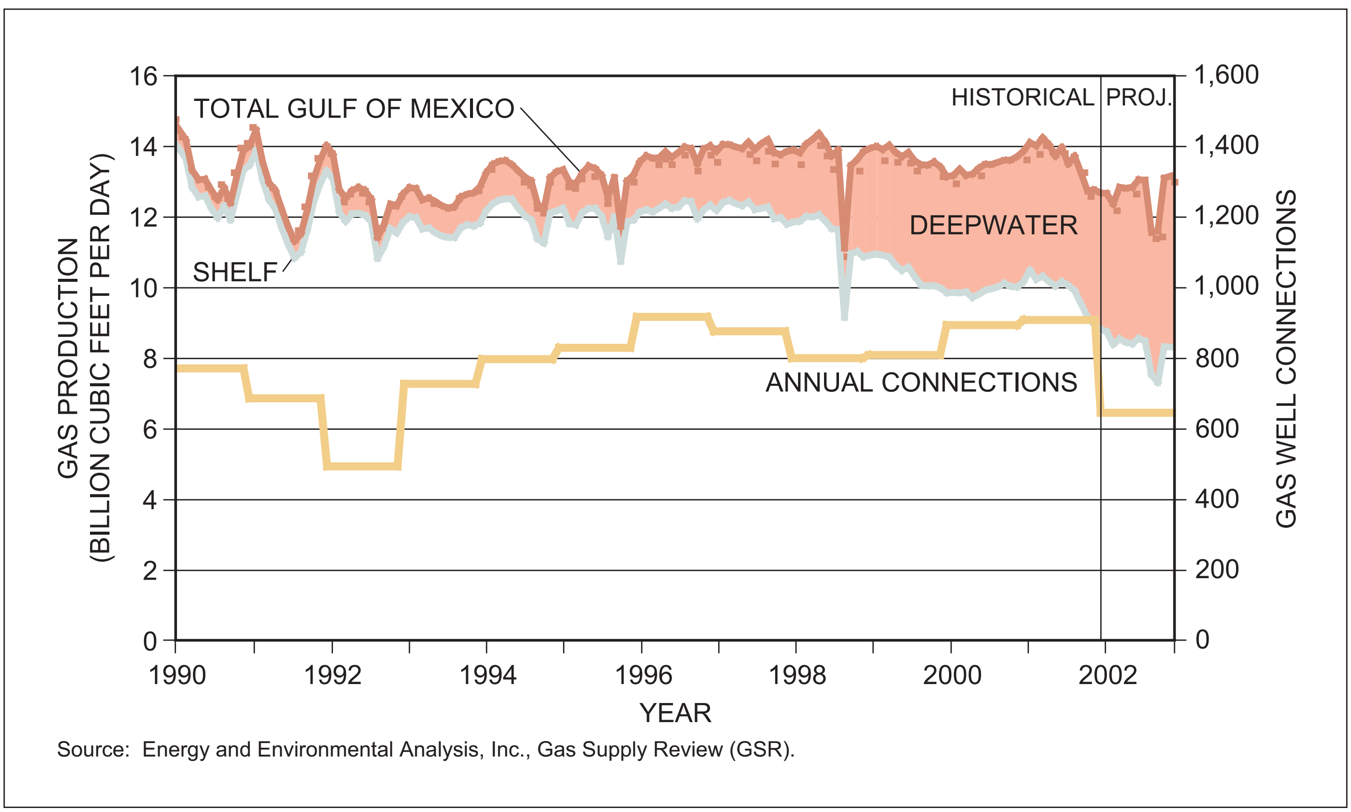


Figure S4-59. Gulf of Mexico Shelf and Deepwater – Production and Gas Well Connections

However, the deepwater was unable to mitigate the large decline in Shelf production in 2001 and 2002.

The DW GOM has relatively little pipeline and processing facility infrastructure. Only in the last 10 years has it been feasible to set TLPs, spars, and other floating processing facilities at the water depths necessary to bring production to market. Wells are now being drilled in water depths greater than 6000'. The cost to set these large facilities can be well over $1 billion. As pipeline and processing facility infrastructure continues to expand, smaller fields will become increasingly commercial.

The DW GOM is primarily an oil province as shown by the recent oil production rates, which approach 1 million barrels of oil per day. Some recent discoveries are quoted as having oil reserves greater than 1 billion barrels. Future gas production growth will depend on favorable economics for oil development.

2. Well Performance

The DW GOM typical well was analyzed in terms of vintage. The rate versus cumulative production performance indicates that recent completions have approximately double the initial rates as compared to 1990-1995 completions and EURs remain large. (See Figure S4-60.)

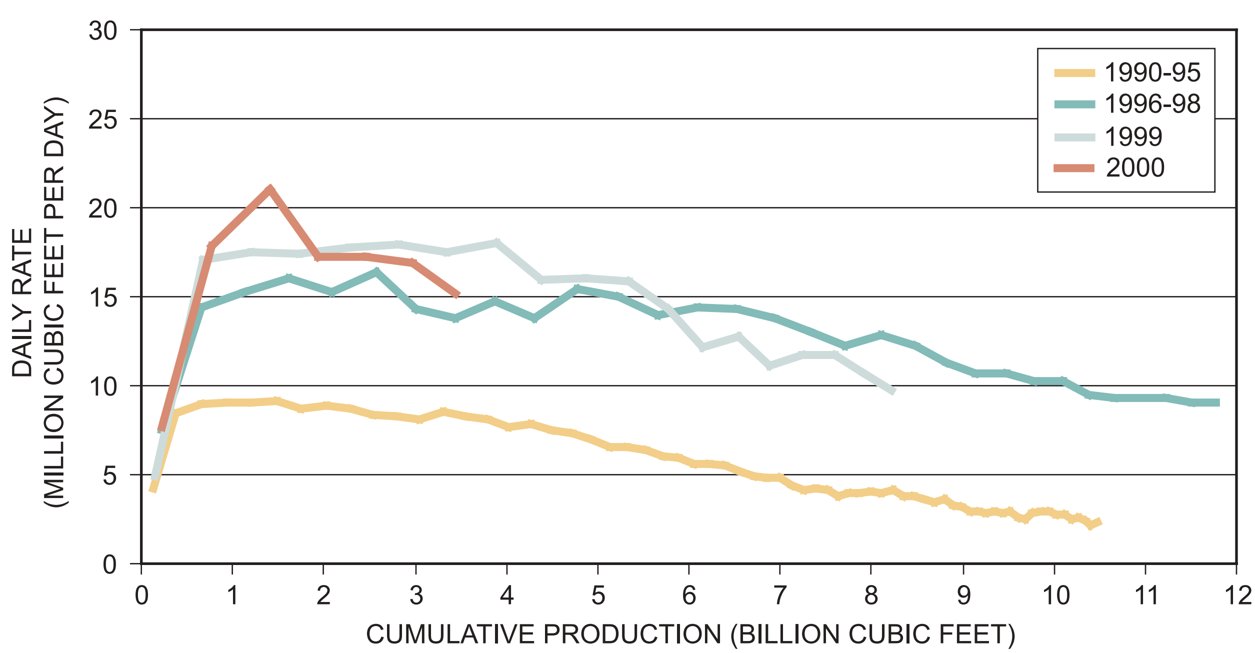
3. Reserves

Reserve additions in the DW GOM averaged 1.2 TCF/year over the period 1993 to 1999, and then jumped to 2.1 TCF in 2000 and 3.8 TCF in 2001. Of critical importance to maintaining and even increasing production rates from the DW GOM will be whether the industry can continue to find new resources on the pace it set in 2000 and 2001 and develop the reserves in a timely manner. (See Figure S4-61.)

C. Eastern Gulf Coast

1. Historical Performance

Production from the Eastern Gulf Coast basin increased gradually in the early 1990s from peak rates of 4.2 BCF/D in 1990 and 1991 up to 4.7 BCF/D in 1997, an increase of 0.5 BCF/D. Since peaking in 1997, production from the basin has declined by just over 1 BCF/D to 3.6 BCF/D at the end of 2002. Drilling increased significantly in 2000 and 2001 as



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-60. Gulf of Mexico Deepwater – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production

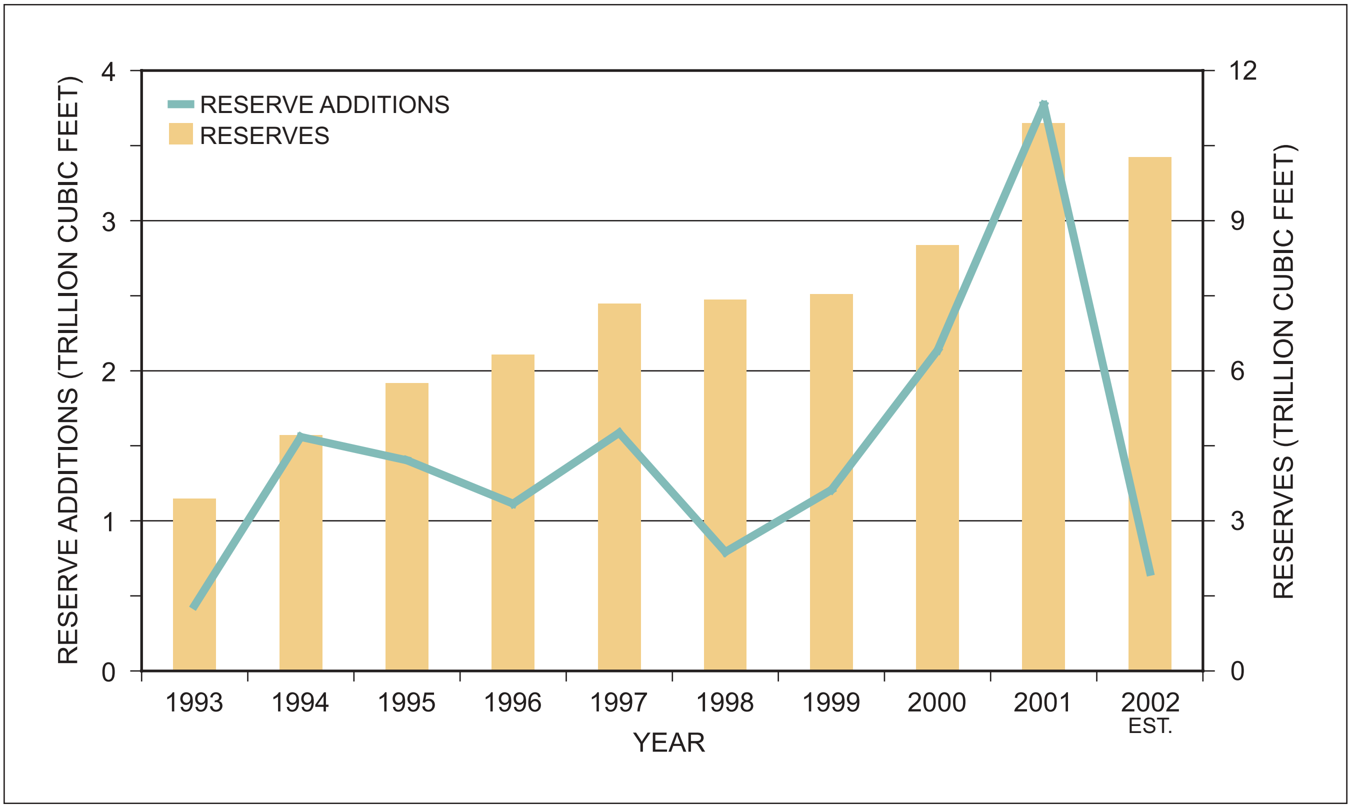


Figure S4-61. Gulf of Mexico Deepwater – Reserves and Annual Reserve Additions

gas connections rose from an average of 370 in 1998 and 1999 to near 600 in 2001. This big run-up in activity was able to flatten the decline. However, production is estimated to have fallen steeply as drilling fell to more historical levels in 2002. (See Figure S4-62.)

2. Well Performance

EUR per connection, after ramping up significantly in the mid-1990s as the highly prolific Norphlet Trend was initially developed, fell back to levels of approximately 2 BCF/connection in the late 1990s. As drilling ramped up in 2000 and 2001 EUR/connection fell to less than 1.5 BCF/connection, a 25% drop in average EUR. (See Figure S4-63.)

3. Base Decline

Base decline rates increased in the Eastern Gulf Coast, from approximately 20% in the early 1990s to 30-35% more recently. In the early 1990s, annual drilling had to add about 800 MMCF/D in new production, that figure has risen to approximately 1.0-1.2 BCF/D more recently. (See Figures S4-64 and S4-65.)

4. Reserves

As production has fallen in the late 1990s in Southern Louisiana, so have total Proved Reserves and Proved, Producing Reserves. Total Proved Reserves have fallen from just over 6 TCF in 1997 to less than 5.5 TCF in 2001. R/P has steadily fallen from a peak of 6.5 in 1998 to approximately 5.7 in 2001. Proved, Producing Reserves have also fallen by a little over 1 TCF and the Proved, Producing R/P has fallen from 4.5 to near 3.5 as more aggressive exploitation plans were able to lower R/P. (See Figure S4-66.)

D. East Texas and North Louisiana

1. Historical Performance

Gas production in the historical East Texas and North Louisiana region grew marginally in the early 1990s, as non-associated gas well production was just able to overcome declining associated gas production. In the late 1990s and early 2000s, gas production increased significantly as East Texas and North Louisiana gas production grew over 1 BCF/D from a low of 3.5 BCF/D in mid-1999 to just over 4.5 BCF/D by the end of 2002. (See Figure S4-67.)

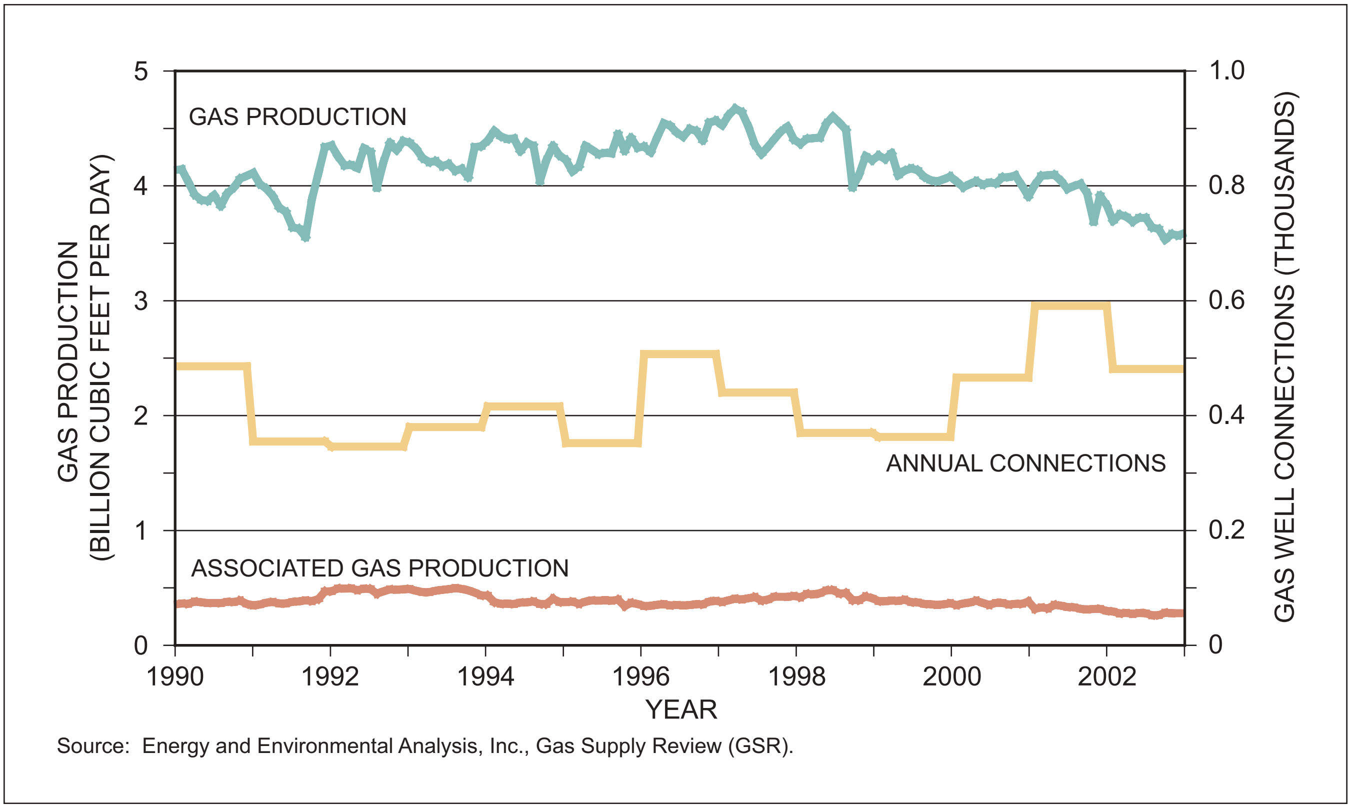


Figure S4-62. Eastern Gulf Coast – Production and Gas Well Connections

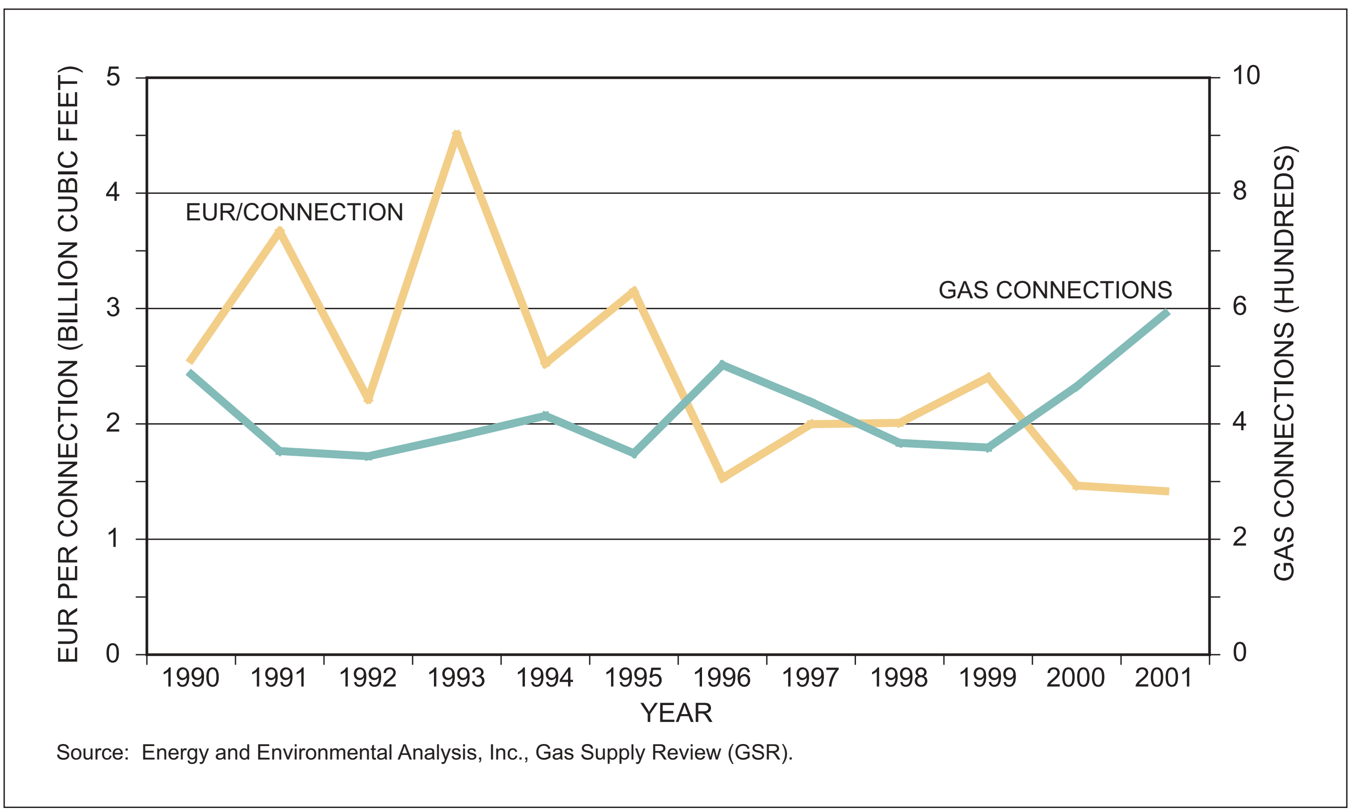
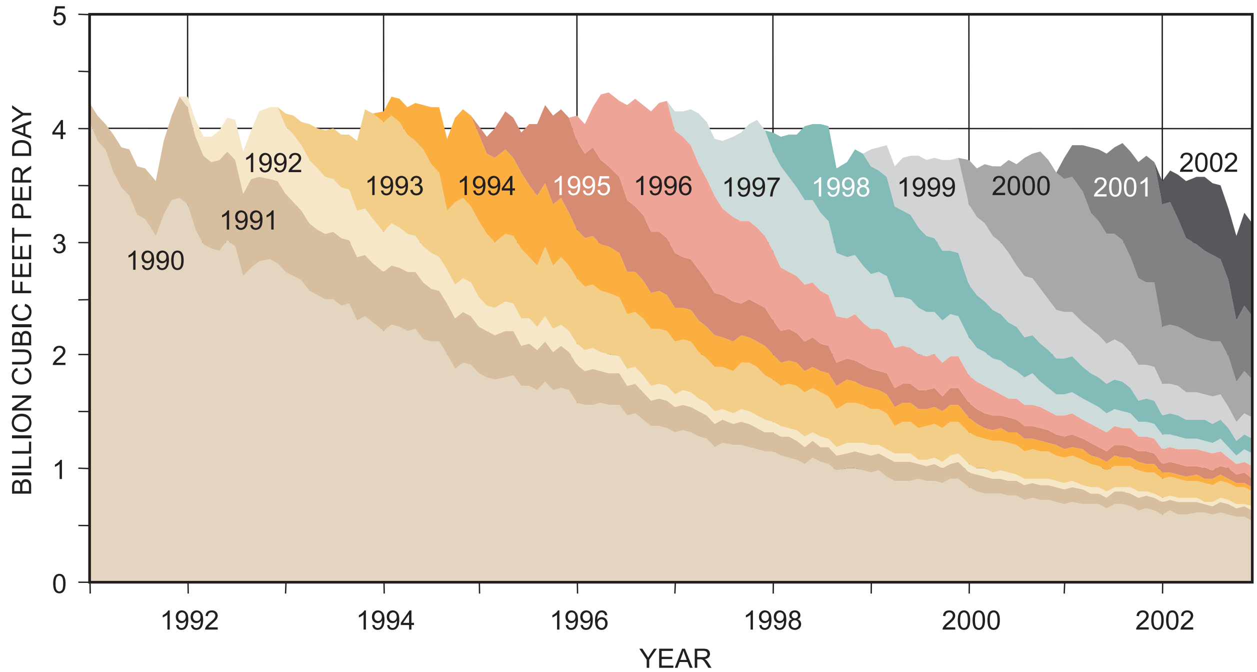
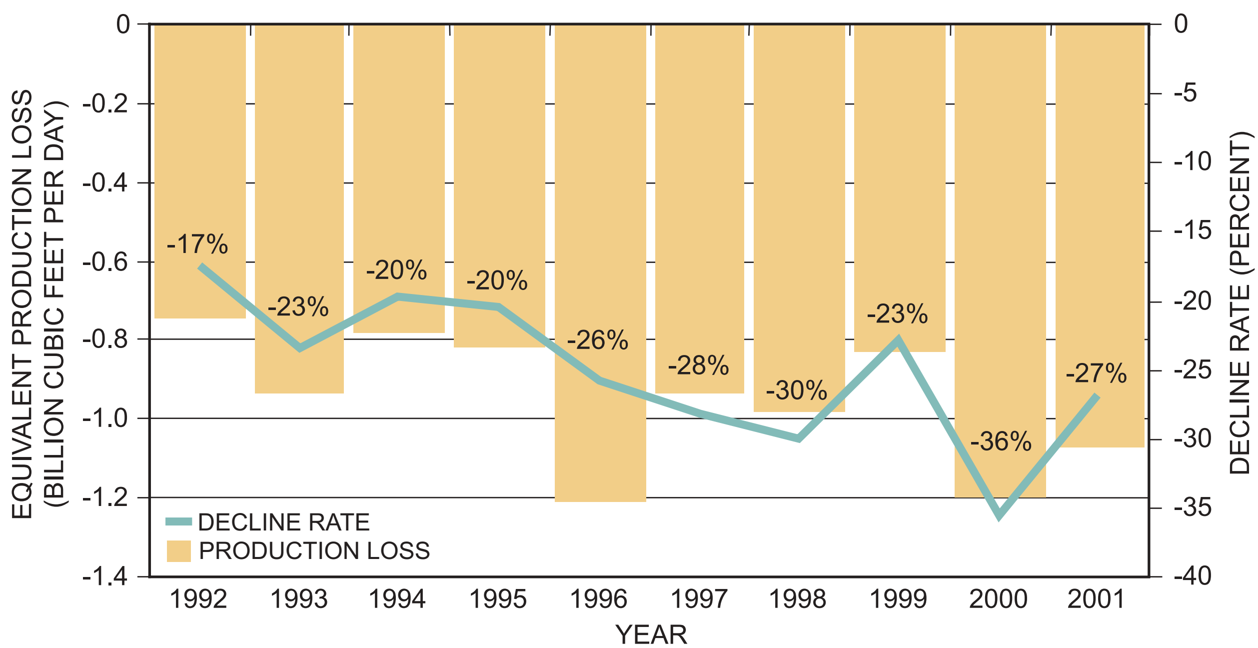


Figure S4-63. Eastern Gulf Coast – Estimated Ultimate Recovery per Gas Connection



Source: IHS Energy Group.

Figure S4-64. Eastern Gulf Coast – Daily Wet Gas Production from Gas Wells, by Year of Production Start



Source: IHS Energy Group.

Figure S4-65. Eastern Gulf Coast – Decline Rate of Base Gas Production if No New Wells had been Drilled, and Equivalent Production Loss

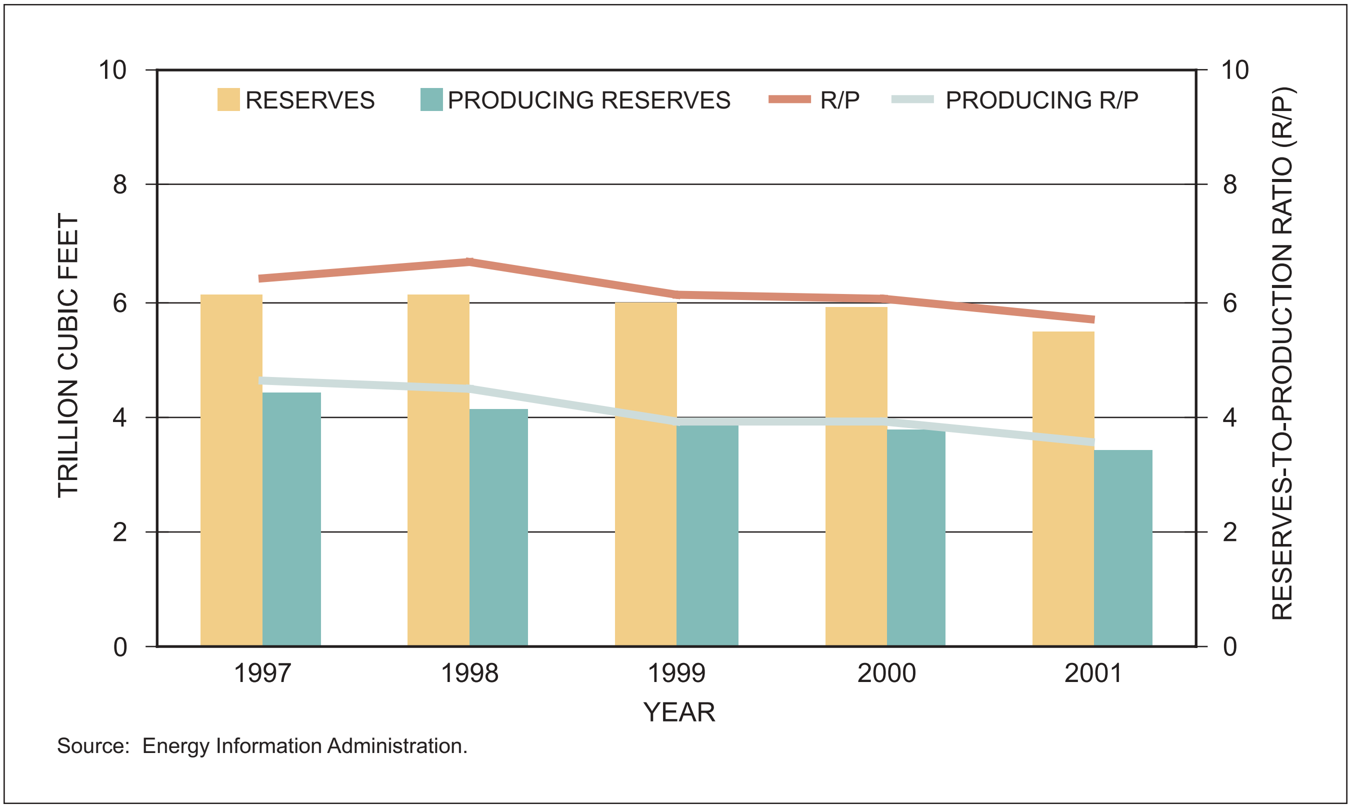


Figure S4-66. South Louisiana Gulf Coast – Wet Gas Reserves

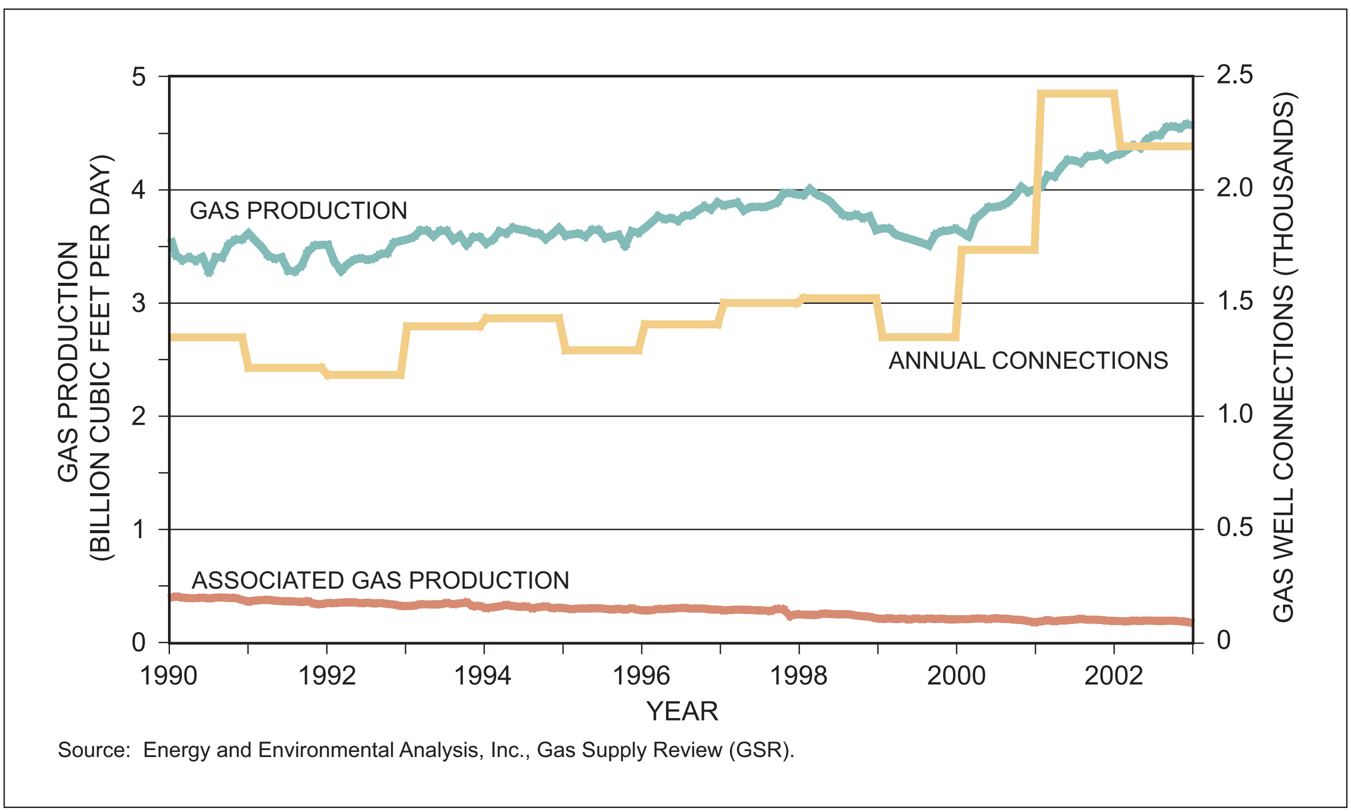


Figure S4-67. East Texas/North Louisiana – Production and Gas Well Connections

The sustained production increases recently have come from nonconventional gas resources, the tight gas sands of the Cotton Valley Formation and Barnett Shale. As these nonconventional plays became increasingly economic, well connections increased three-fold in Cotton Valley and five-fold in the Barnet Shale from 1999 through 2002. Gas production from the Cotton Valley increased from approximately 1.3 BCF/D mid-1999 up to an estimated 1.9 BCF/D by the end of 2002. Production gains from the Barnett Shale were even more striking, rising from under 0.1 BCF/D in mid-1999 to an estimated 0.7 BCF/D by the end of 2002. (See Figures S4-68 and S4-69.)

The rising nonconventional production from East Texas and North Louisiana is being driven by improved, more economic stimulation techniques. The percentage of completions that have undergone fracture stimulation has increased from approximately 40% in 1990-1995 to essentially 100% in 2001. Many of the more recent fracture stimulations have been conducted with water, but other substances are also used. The impact of this improvement is that smaller, tighter reserve targets, which were previously uneconomic, can now be drilled. (See Figure S4-70.)

2. Well Performance

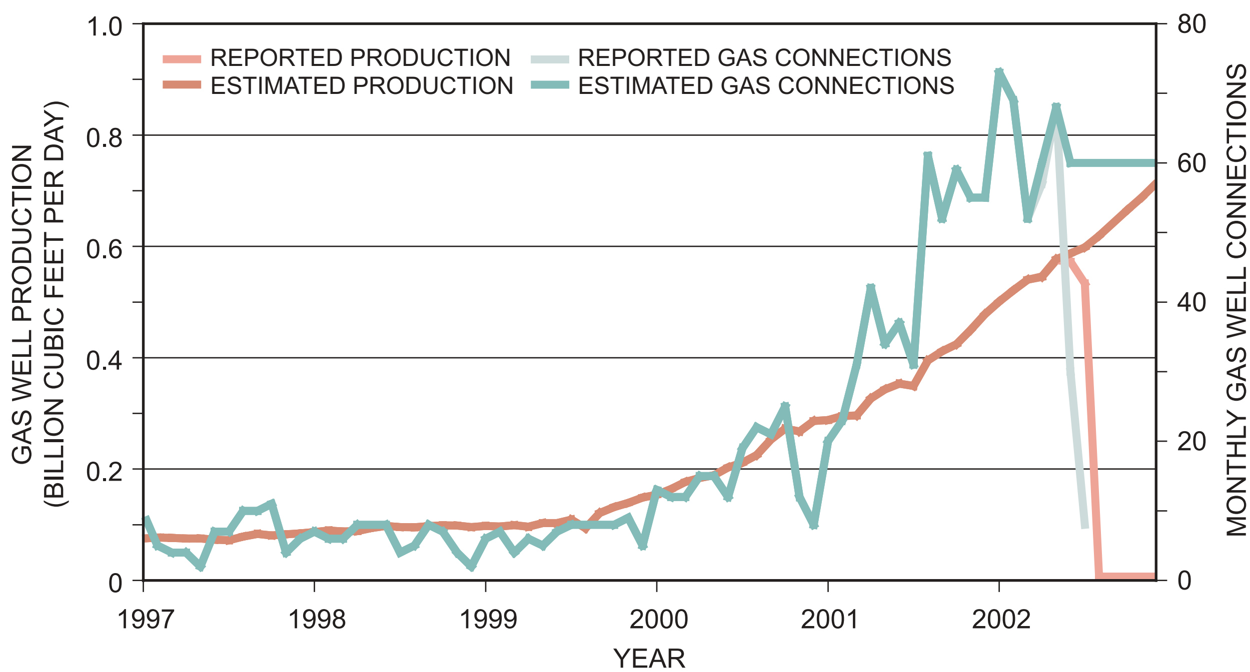
Performance from wells in East Texas and North Louisiana was analyzed by vintage. As per the rate vs. time and rate vs. cumulative production plots, newer wells achieved higher peak rates, yet steeper declines. (See Figures S4-71 and S4-72.)

EUR per connection decreased through 1998 from a high of a 1 BCF/connection in 1992 down to 0.7 BCF/connection in 1998. EUR per connection stayed flat in 1999 and 2000, with wells producing between 0.7-0.75 BCF/connection. (See Figure S4-73.)

Decline rates in East Texas/North Louisiana have been accelerated, such that replacing production becomes increasingly challenging. East Texas/ North Louisiana wells lose almost 60% of their peak deliverability after the first 12 months of production. Thereafter, the wells begin a much shallower decline rate, with steady production of about 200 MCF/D for very long periods.

3. Base Decline

As the decline rate of each year's new wells increases, so does the decline of the underlying base production.



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-68. Barnett Shale – Production and Monthly Gas Well Connections

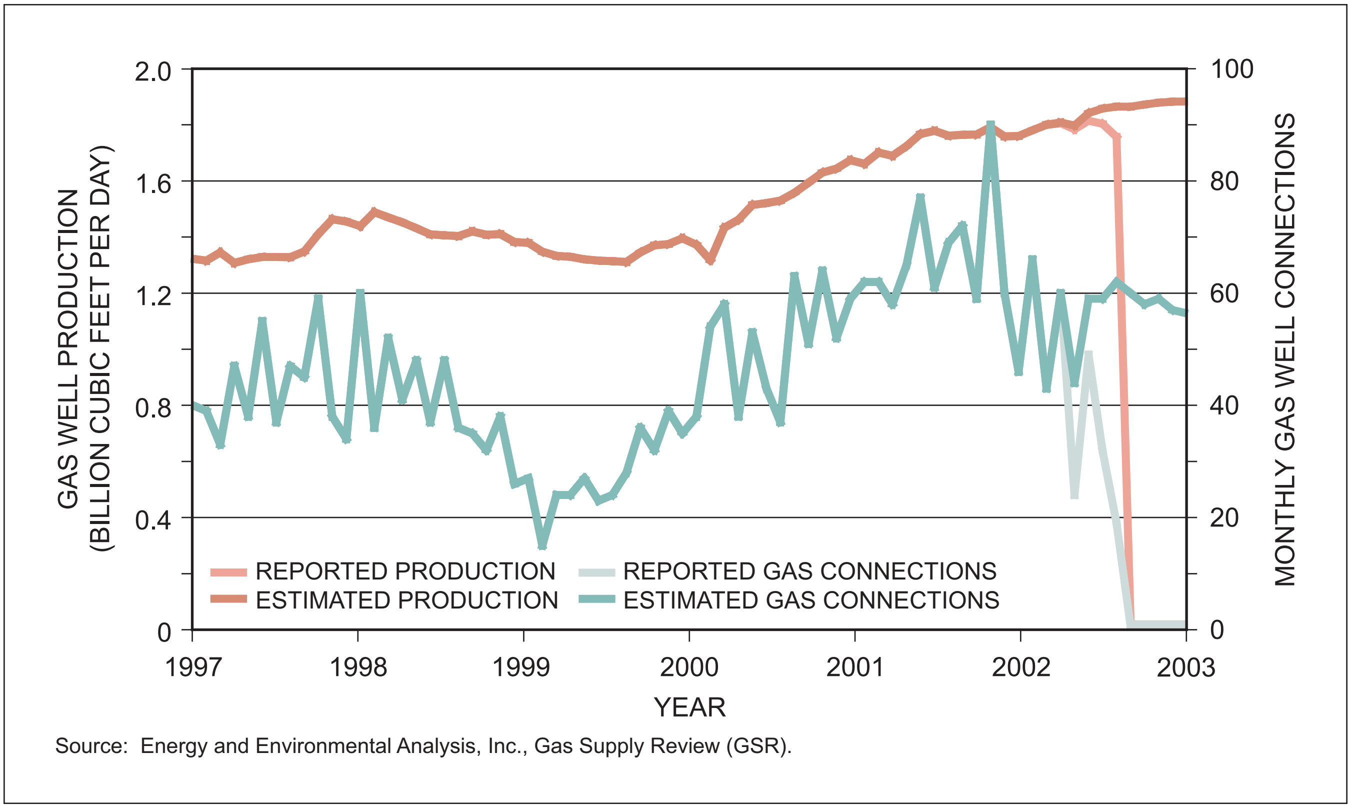


Figure S4-69. Cotton Valley Formation – Production and Monthly Gas Well Connections

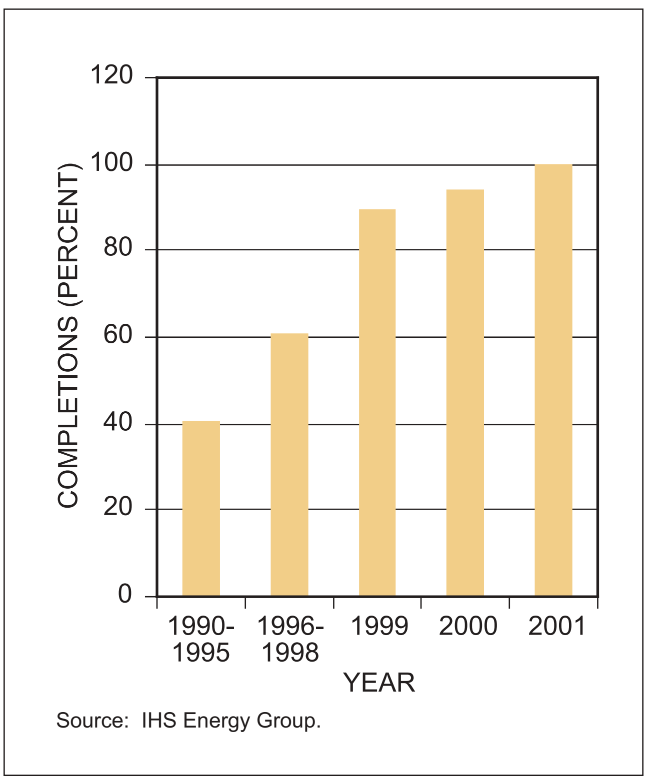


Figure S4-70. Percentage of Completions in East Texas that were Fracture Stimulated

This means that each year, more production must be brought on stream simply to hold production flat. In East Texas and Louisiana, new wells must produce at least 1 BCF/D to grow production. If activity stopped completely in this region, production would decline by about 25%. (See Figures S4-74 and S4-75.)

4. Reserves

Gas reserves in East Texas/North Louisiana have climbed nearly 2 TCF from 1997 to 2001. The reserves-to-production ratio is about 9 years, a slight increase from the historical 8.8. (See Figure S4-76.)

E. South Texas Gulf Coast

1. Historical Performance

The South Texas Gulf Coast has contributed approximately 15% of the lower-48 natural gas supply over the past 20 years. After declining in the early 1990s, gas production grew substantially in the mid-1990s, with production increasing from an average of 5.5 BCF/D in 1990 to a peak of 7.0 BCF/D at the end of 1996. Production increases slowed in the latter half of the

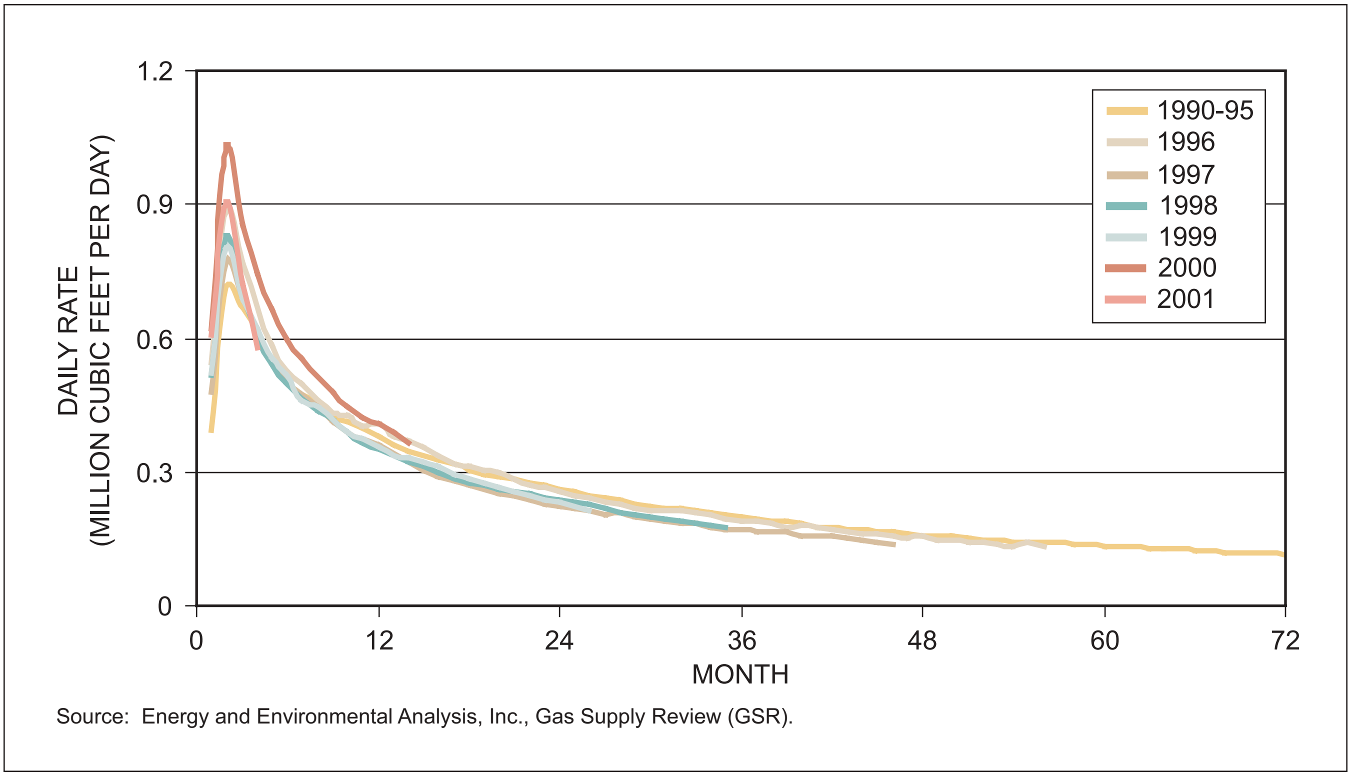


Figure S4-71. East Texas/North Louisiana – Average Daily Gas Well Production vs. Time, by Year of First Production

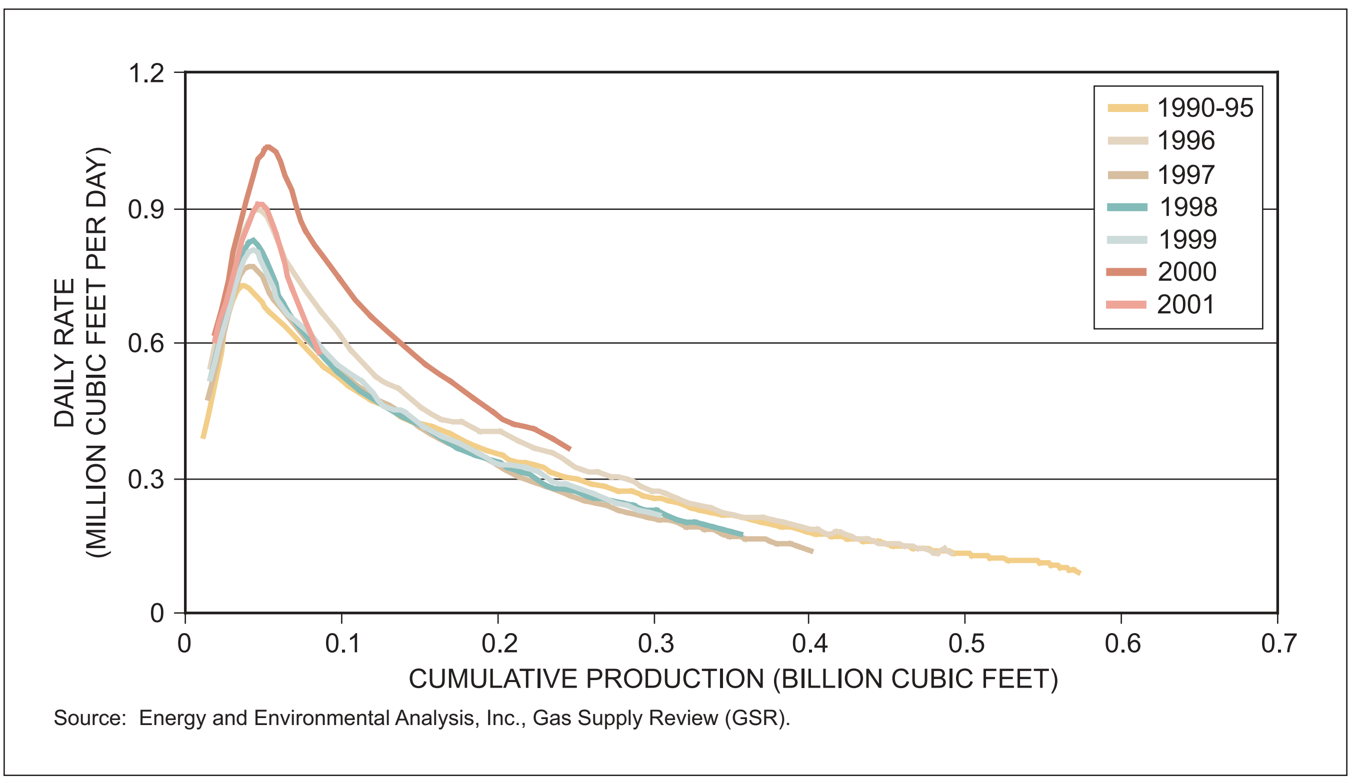
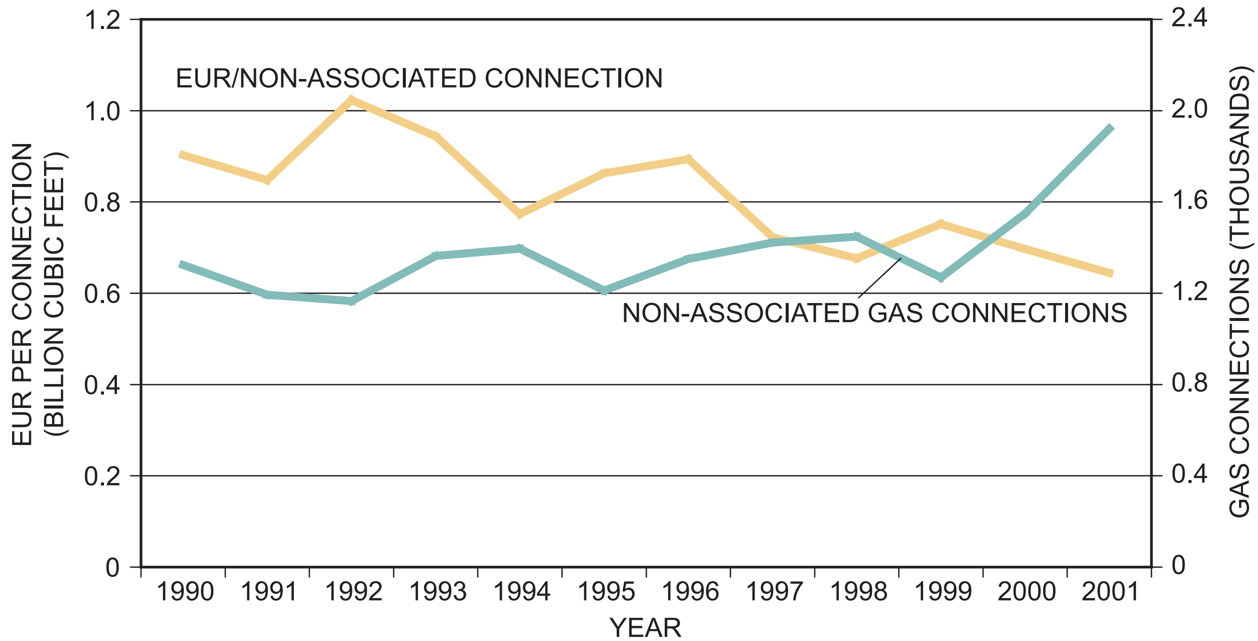
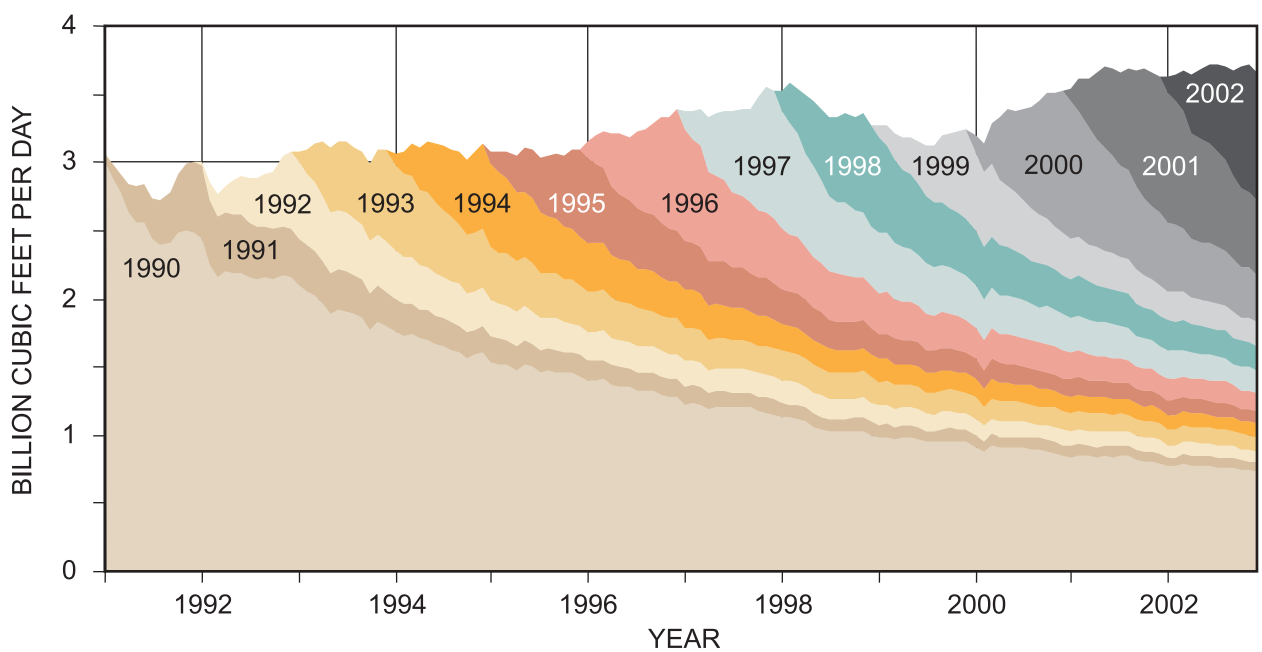


Figure S4-72. East Texas/North Louisiana – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-73. East Texas/North Louisiana – Estimated Ultimate Recovery per Gas Connection (excludes Barnett Shale)



Source: IHS Energy Group.

Figure S4-74. East Texas/North Louisiana – Daily Wet Gas Production from Gas Wells, by Year of Production Start

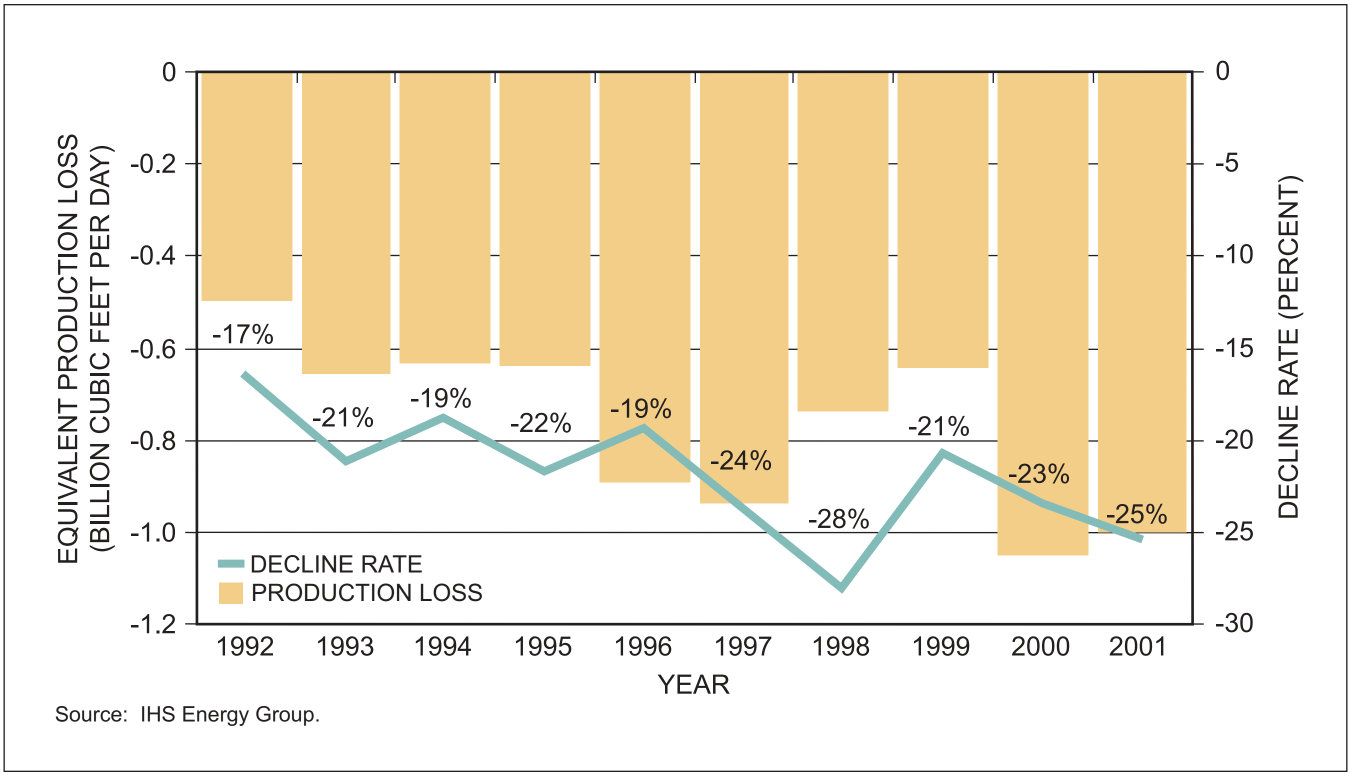


Figure S4-75. East Texas/North Louisiana – Decline Rate of Base Gas Production if No New Wells had been Drilled, and Equivalent Production Loss

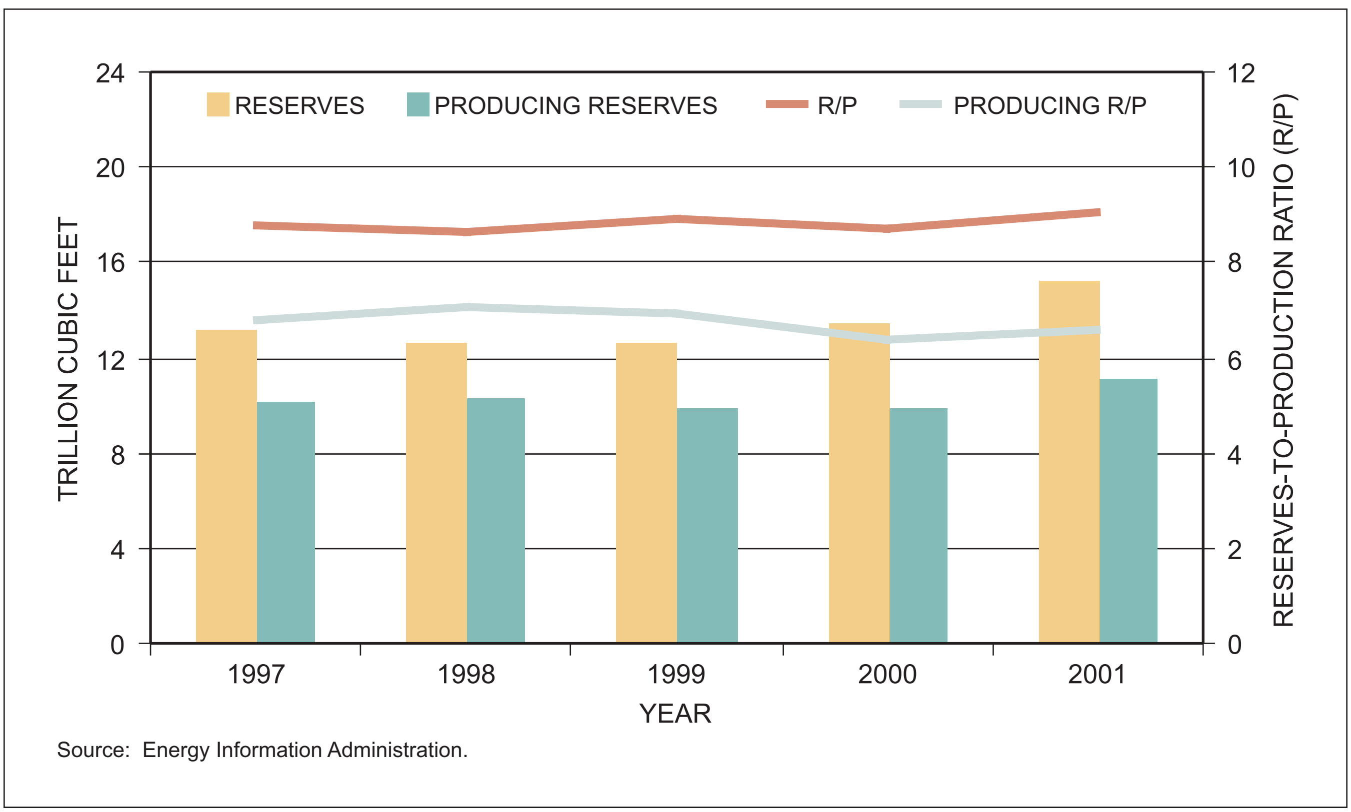


Figure S4-76. East Texas/North Louisiana – Wet Gas Reserves decade, despite sustained drilling at an average rate of 2,000 gas well connections per year. Even as connections increased to 2,350 in 2001, gas production rolled over and started to decline. This decline accelerated in 2002 as drilling levels fell. Total production loss from the end of 2000 to the end of 2002 totaled approximately 700 MMCF/D. (See Figure S4-77.)

Following decline in the earliest part of the decade, in the mid-1990s the basin experienced relatively robust production growth after 3-D seismic surveys were shot covering the major producing trends. High resolution 3-D seismic allowed the industry to shift exploration to deeper Vicksburg, Frio, and Wilcox traps. In addition to allowing the industry to explore deeper in the basin, the high resolution seismic coverage allowed the industry to more accurately identify and develop smaller reservoir targets in existing fields, lowering the risk of drilling uneconomic wells.

The South Texas annual average rig count has varied from 100 to 180 in the period since 1990. Between 1999 and 2001, the South Texas rig count averaged well over 130 rigs, and peaked at 177 rigs in 2001. Even at high activity levels, South Texas production actually began to fall in 2001 and continued falling in 2002. The inability of the industry to raise production with the high rig count reveals the increasing maturation of the basin's 3-D seismically generated prospects. (See Figure S4-78.)

The majority of the recently discovered deep gas in the South Texas Gulf Coast is qualified as tight by the Texas Railroad Commission. Production from tight gas reservoirs in South Texas more than doubled from 1990 to 1999 to 2.5 BCF/D. (See Figure S4-79.)

As the industry continued to explore and find deeper and tighter reservoirs, advancing fracture stimulation technology was applied to exploit the resource. In 2000 and 2001 almost 50% of completions were sand fracture stimulated, whereas in 1990 only 10% of completions were stimulated in this manner. (See Figure S4-80.)

2. Well Performance

The average South Texas gas well was analyzed in terms of vintage, formation, and depth drilled.

Rate vs. Time and Rate vs. Cumulative Production plots indicate that, on average, recent completions

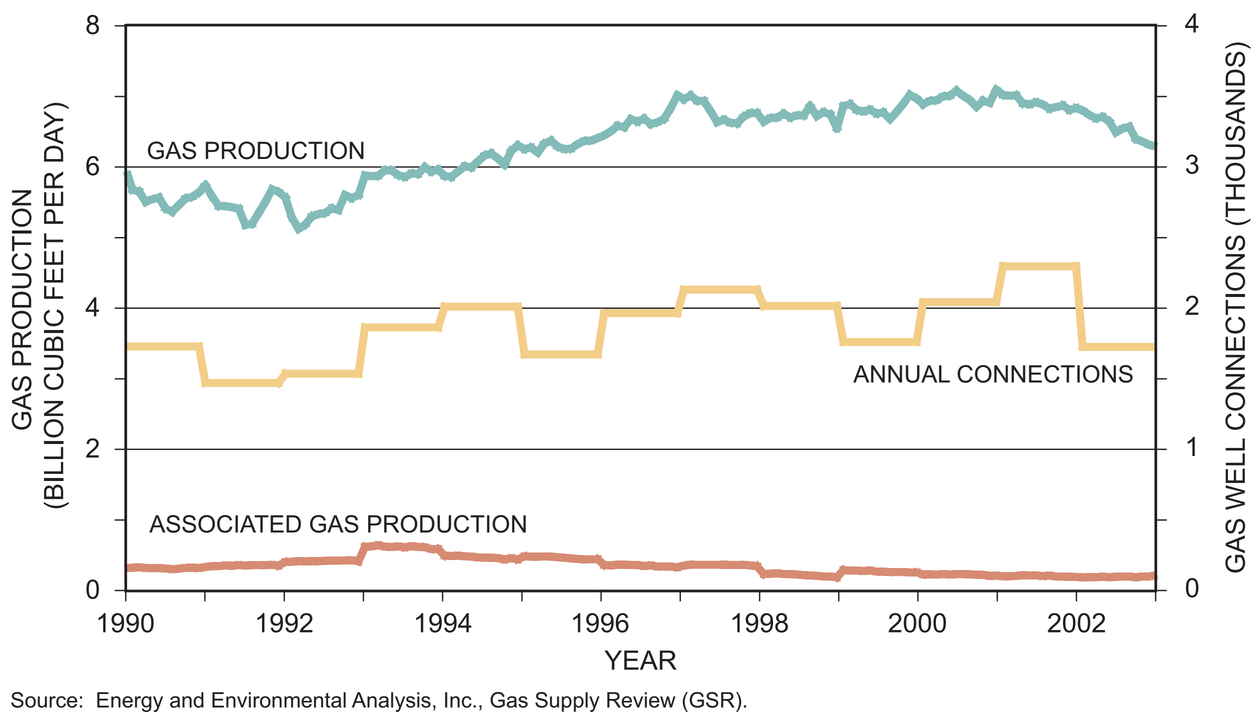


Figure S4-77. South Texas Gulf Coast – Production and Gas Well Connections

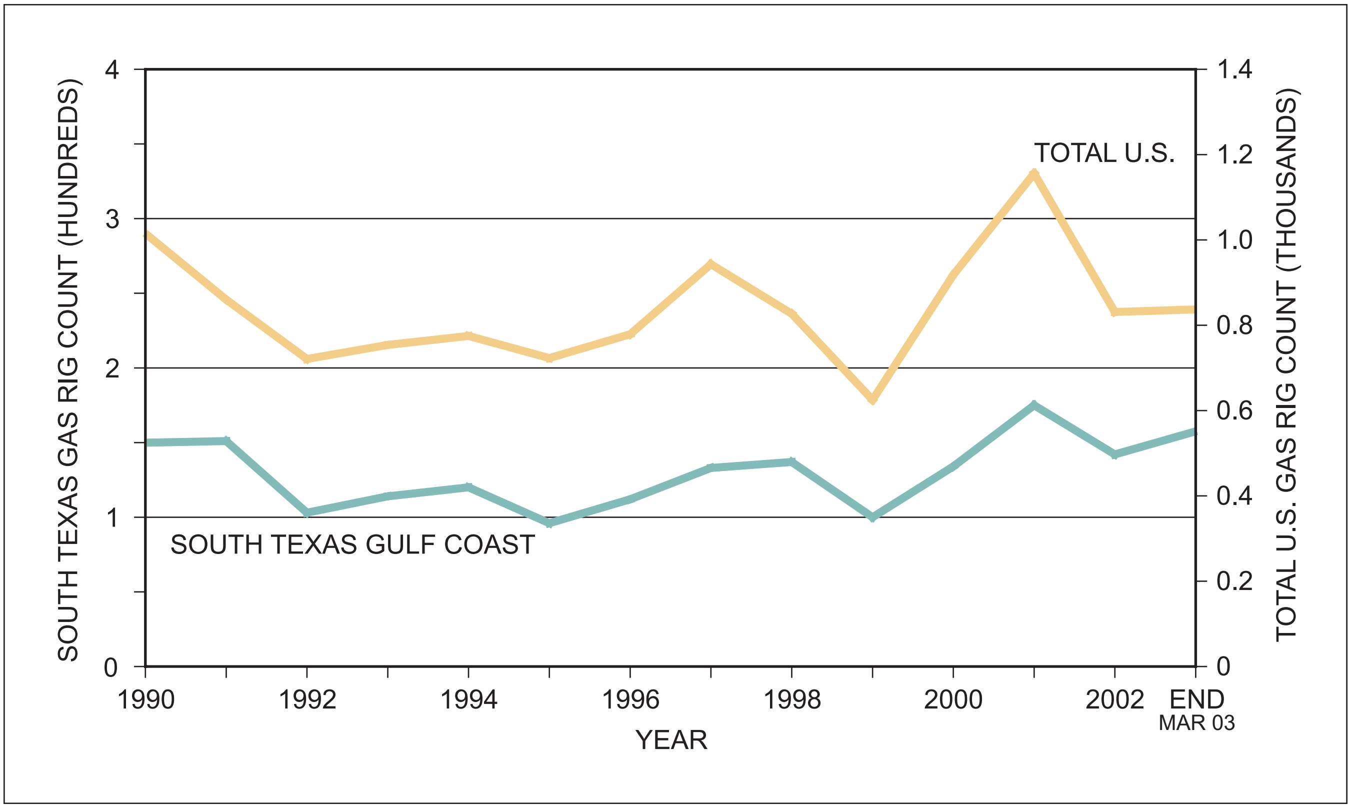


Figure S4-78. South Texas vs. Total U.S. Gas Rig Count

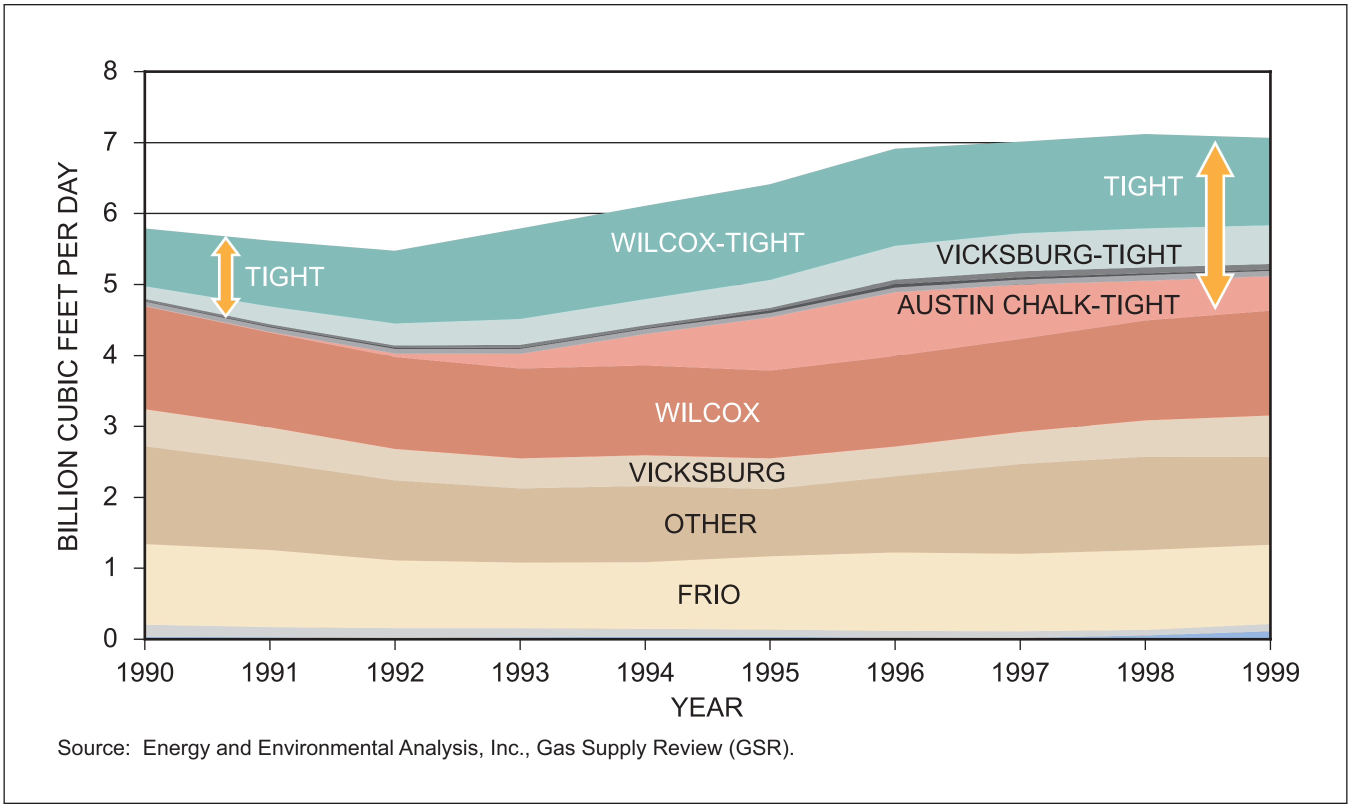


Figure S4-79. Production of Tight Gas from South Texas Gulf Coast Reservoirs

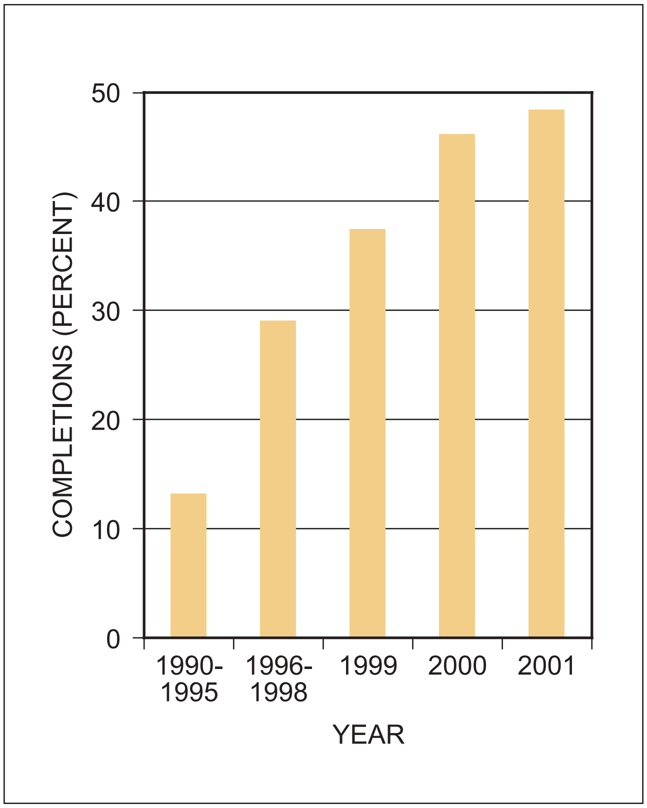


Figure S4-80. South Texas Gulf Coast – Percentage of Completions that were Fracture Stimulated

(1996-2001) have virtually doubled the initial rates of the 1990-1995 completions from approximately 1.2-1.3 MMCF/D to 2.1 MMCF/D. (See Figures S4-81 and S4-82.) However, the EUR increased only marginally though 1999. The 2000-2001 EURs have dropped substantially. (See Figure S4-83.)

When comparing production type curves by depth, the shallow targets (0-10,000 feet) drilled in recent years have higher IPs and similar EURs to the 1990-1995 wells. The wells from 10,000 to 13,000 feet also have higher IPs, but have lower EURs than the 1990-1995 wells. However, gains in both production IPs and EURs were significant at greater than 13,000 foot completion depth. Monobore completions, reservoir commingling, and sand fracture stimulation are some of the fundamental drivers of the increases. (See Figures S4-84, S4-85, S4-86, S4-87, S4-88, and S4-89.)

The majority of the new deep gas arises from the Frio, Vicksburg, and Wilcox formations. The average IPs for the 1999-2000 Frio completions is 1.5 MMCF/D as compared to 0.6 MMCF/D in 1990-1995. The average IPs for the 1999-2001 Vicksburg completions is approximately 4 MMCF/D versus 1.9 MMCF/D in 1990-1995. Finally, the Wilcox 1999-2001 completions average near

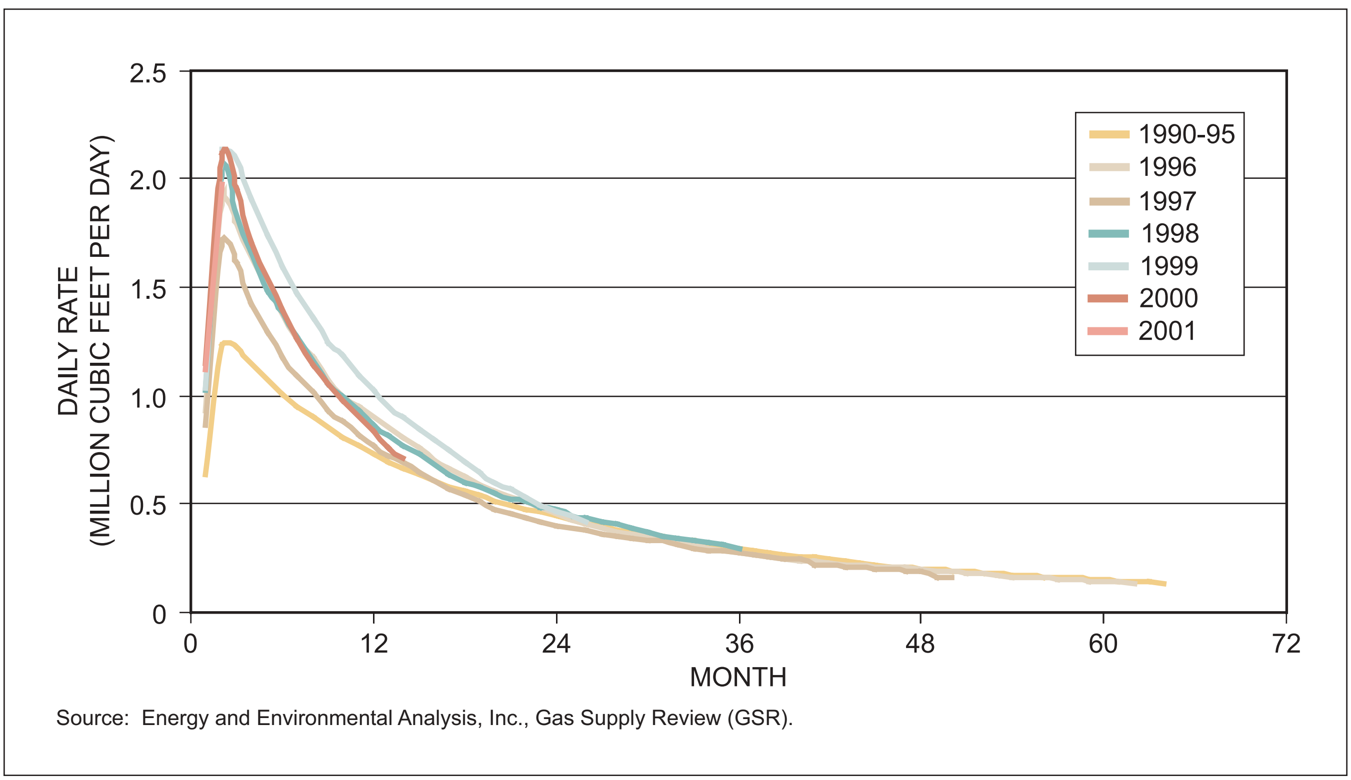
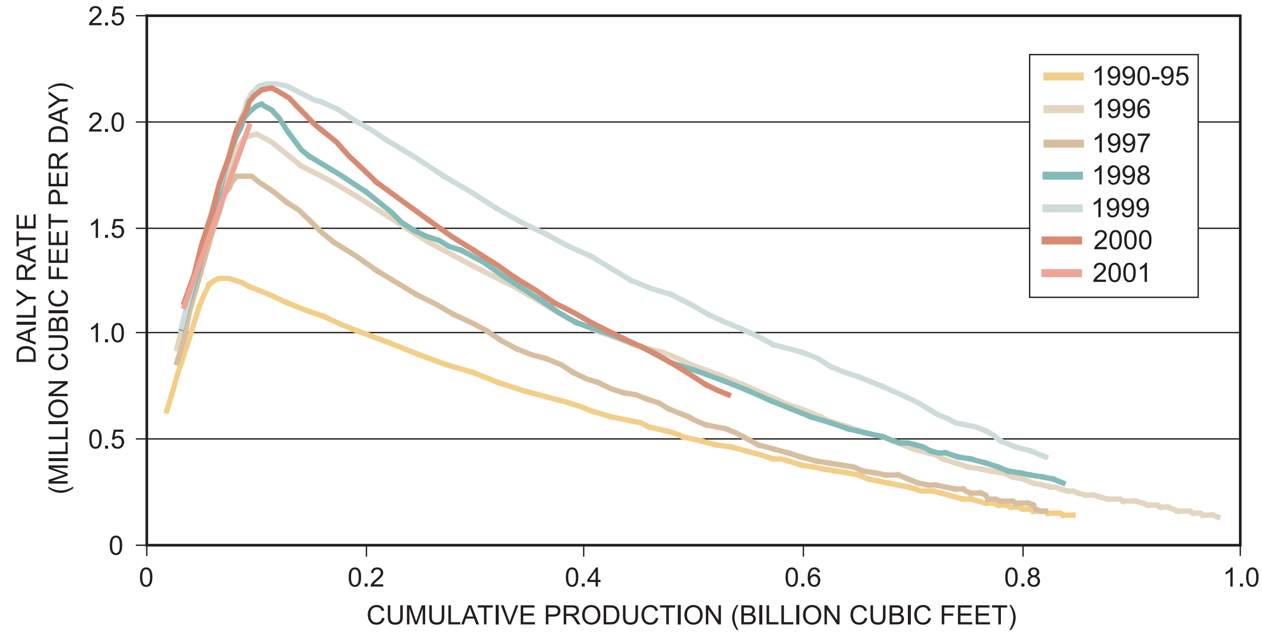
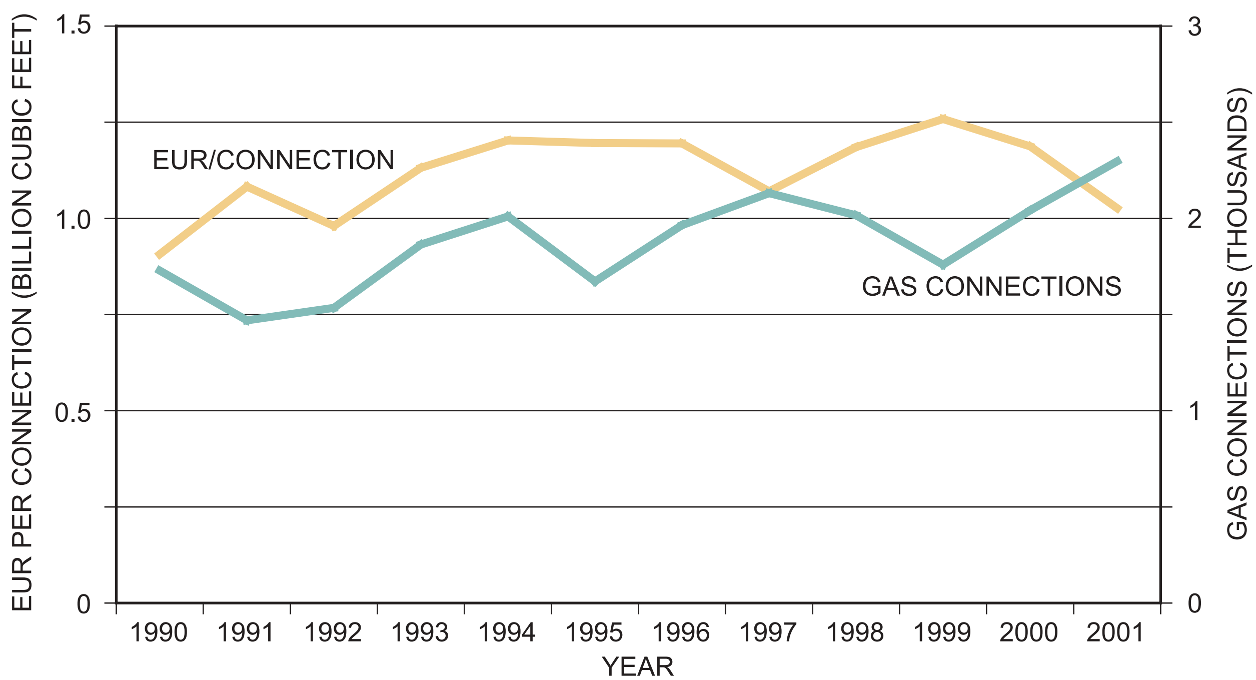


Figure S4-81. South Texas Gulf Coast – Average Daily Gas Well Production vs. Time, by Year of First Production



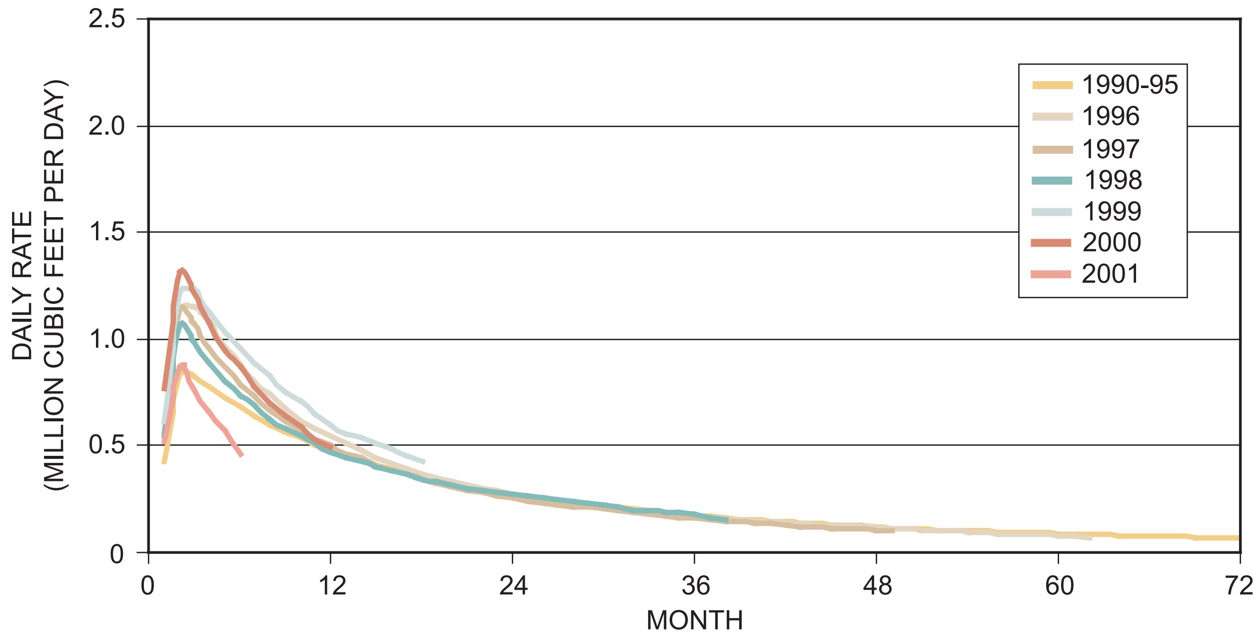
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-82. South Texas Gulf Coast – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production



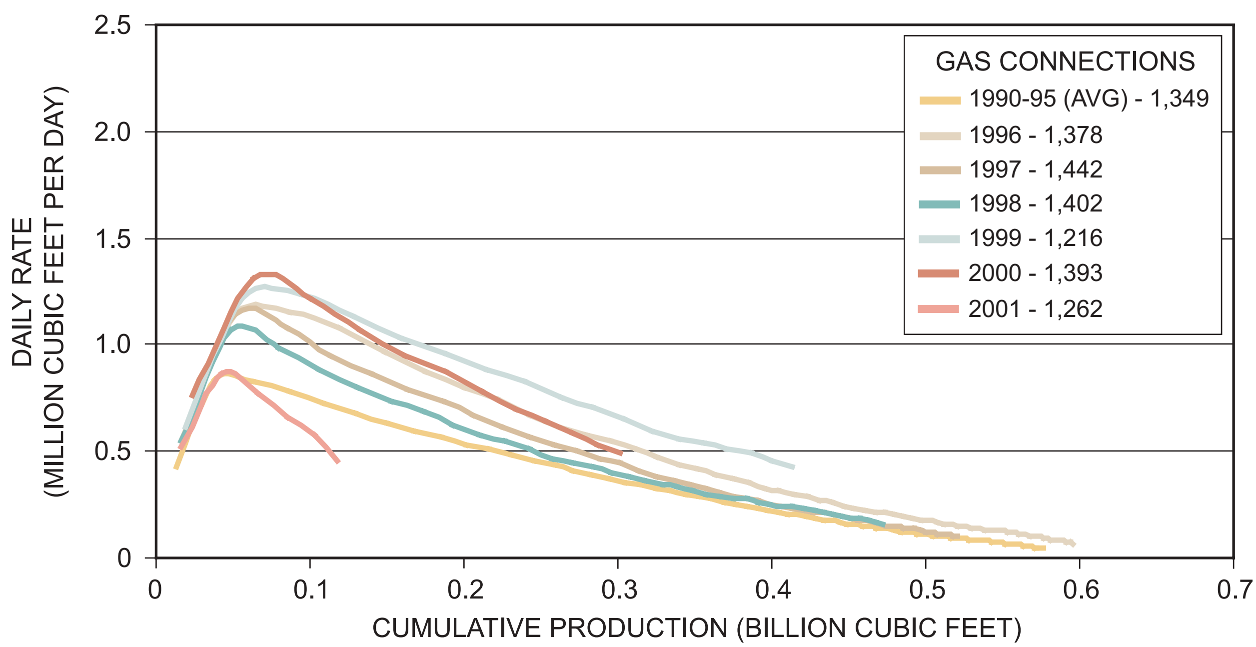
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-83. South Texas Gulf Coast – Estimated Ultimate Recovery per Gas Connection



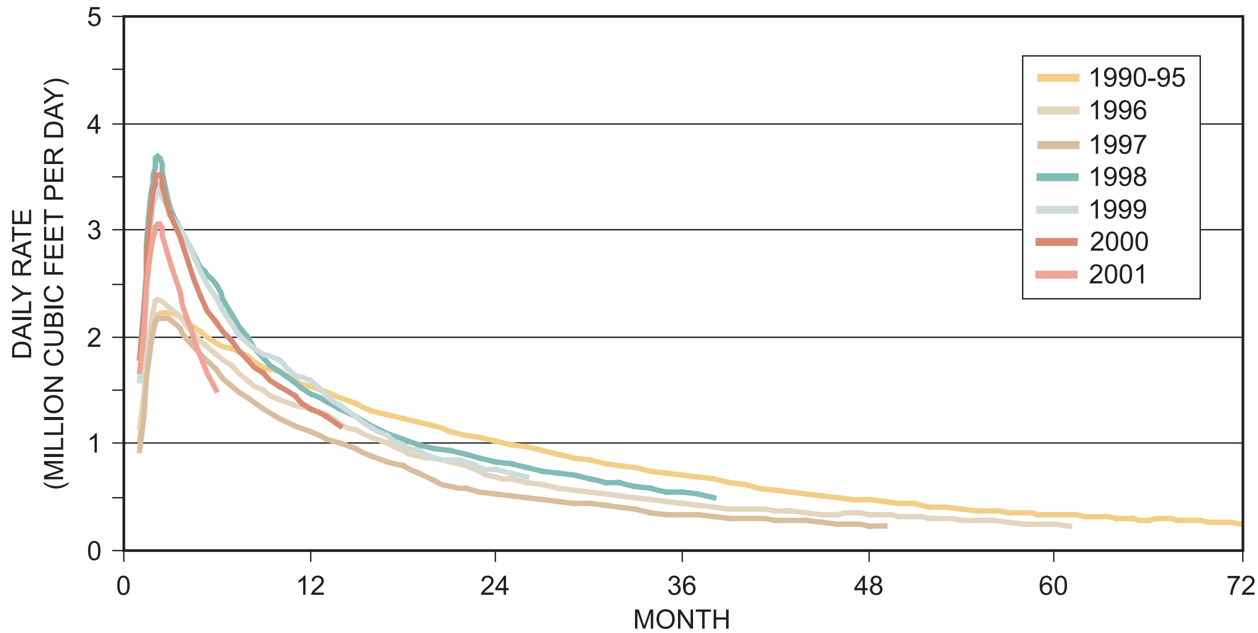
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-84. South Texas Gulf Coast – Average Daily Gas Well Production vs. Time, by Year of First Production (Wells from 0 to 10,000 Feet)



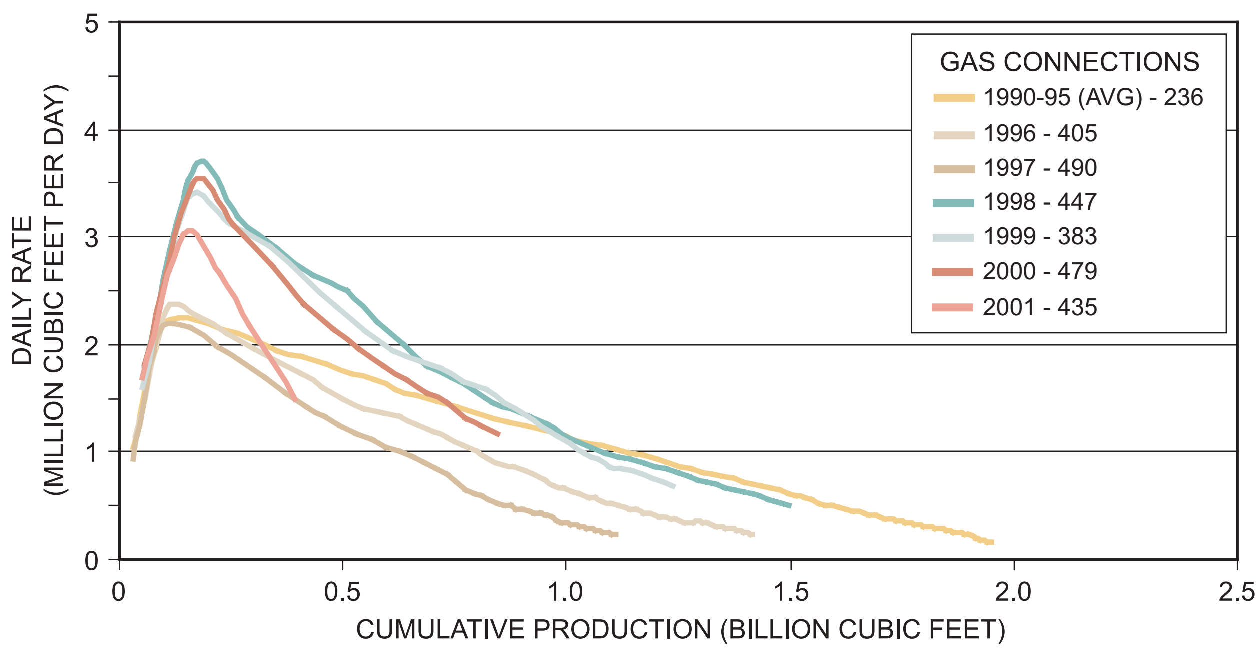
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-85. South Texas Gulf Coast – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production (Wells from 0 to 10,000 Feet)



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-86. South Texas Gulf Coast – Average Daily Gas Well Production vs. Time, by Year of First Production (Wells from 10,000 to 13,000 Feet)



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-87. South Texas Gulf Coast – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production (Wells from 10,000 to 13,000 Feet)

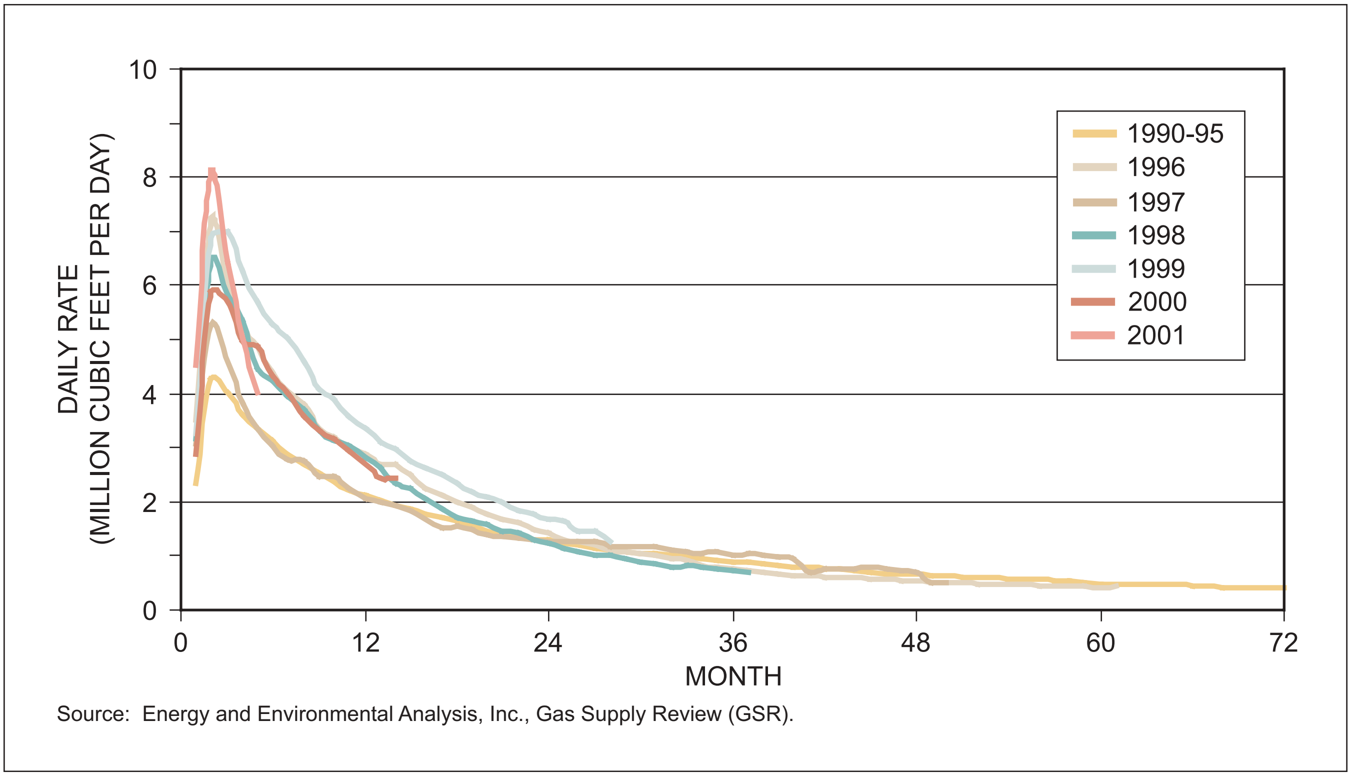


Figure S4-88. South Texas Gulf Coast – Average Daily Gas Well Production vs. Time, by Year of First Production (Wells greater than 13,000 Feet)

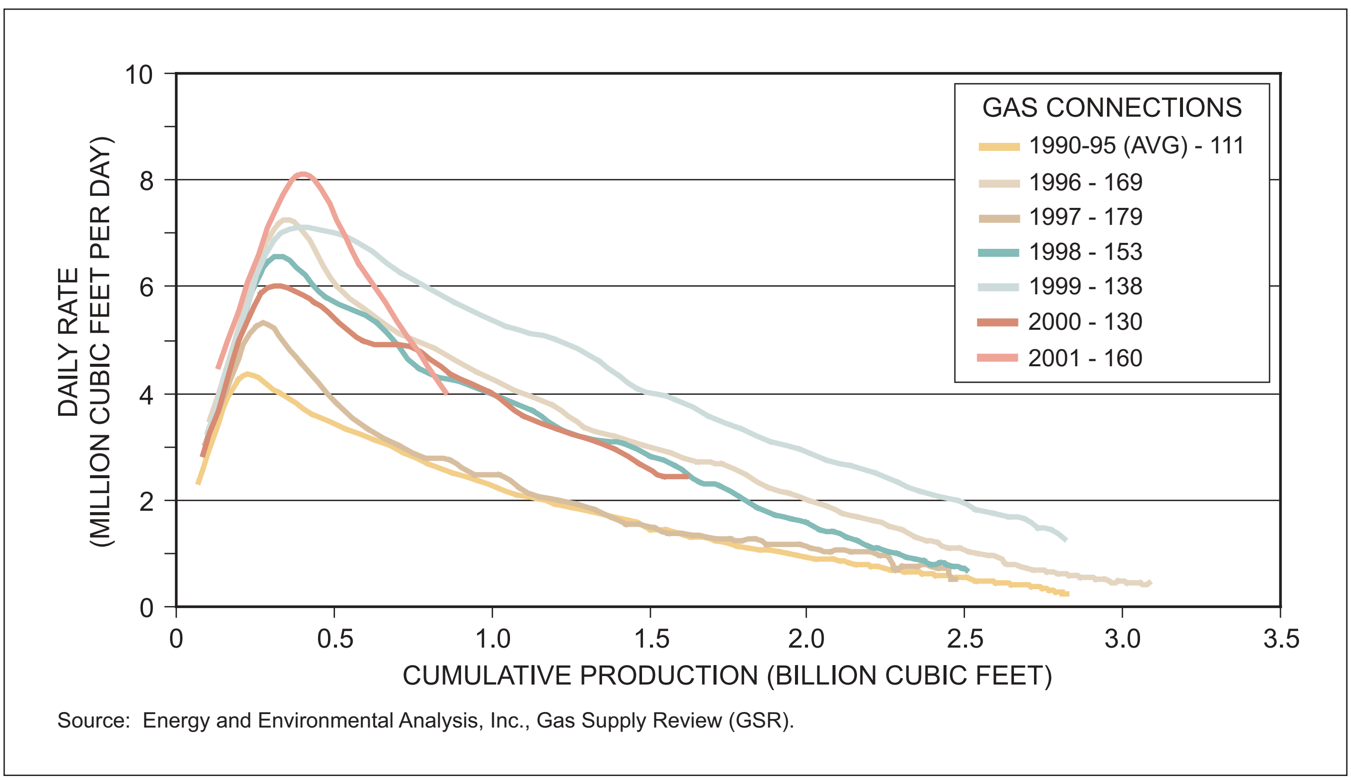


Figure S4-89. South Texas Gulf Coast – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production (Wells greater than 13,000 Feet)

3 MMCF/D versus 2 MMCF/D in 1990-1995. Due to reduced prospect size, 2001 production from these formations dropped from 5.5 BCF/D in January to 4.9 BCF/D by December. (See Figures S4-90, S4-91, S4-92, S4-93, S4-94, and S4-95.)

Specific examples of improved technology that has helped exploit South Texas include the following:

1. The advent of PDC bits and synthetic oil base mud has greatly increased the rate of penetration which has, in turn made well costs more commercial. Additionally, the number of wells a rig can drill per year for a given depth has increased by two fold.

2. Expandable casing is especially important in drilling deep sediments, because it allows for smaller casing sizes to start the well. This lowers the cost and decreases the time it takes to drill the well. The expandable casing is run at a smaller size and placed in the wellbore. Once placed, the casing uses a new technology to extrude the casing to a larger size that fits flush against the previous casing string. This allows the next bit size to be bigger and allows for larger production casing to be run once the well has reached total depth. Larger casing sizes allow for larger diameter tubing to be installed in the well. Larger tubing allows for higher production rates from the well.

3. Modern sand fracture stimulations provide for higher conductivity proppant and higher IPs due to larger amounts of proppant placement. New gels that carry the proppant, incur less damage to the gas reservoirs. The better fracture fluids increase the fracture length of the stimulation. It is common to pump over 1 million pounds of bauxite proppant in South Texas deep gas wells.

4. Improved coiled tubing metallurgy increased the use of the monobore completions. The monobore completion does not need tubing, so therefore, the completion can be done without a drilling rig. Additionally, the monobore can be used to perforate and stimulate multiple sands in one well bore. These sands can be isolated with composite material bridge plugs so the next interval can be tested and stimulated. Once all the intervals have been perforated and stimulated, the entire monobore can be cleaned out with a motor and bit place on coiled tubing. Once cleaned out, all the sands produce together which increases the IP of the well. Well life

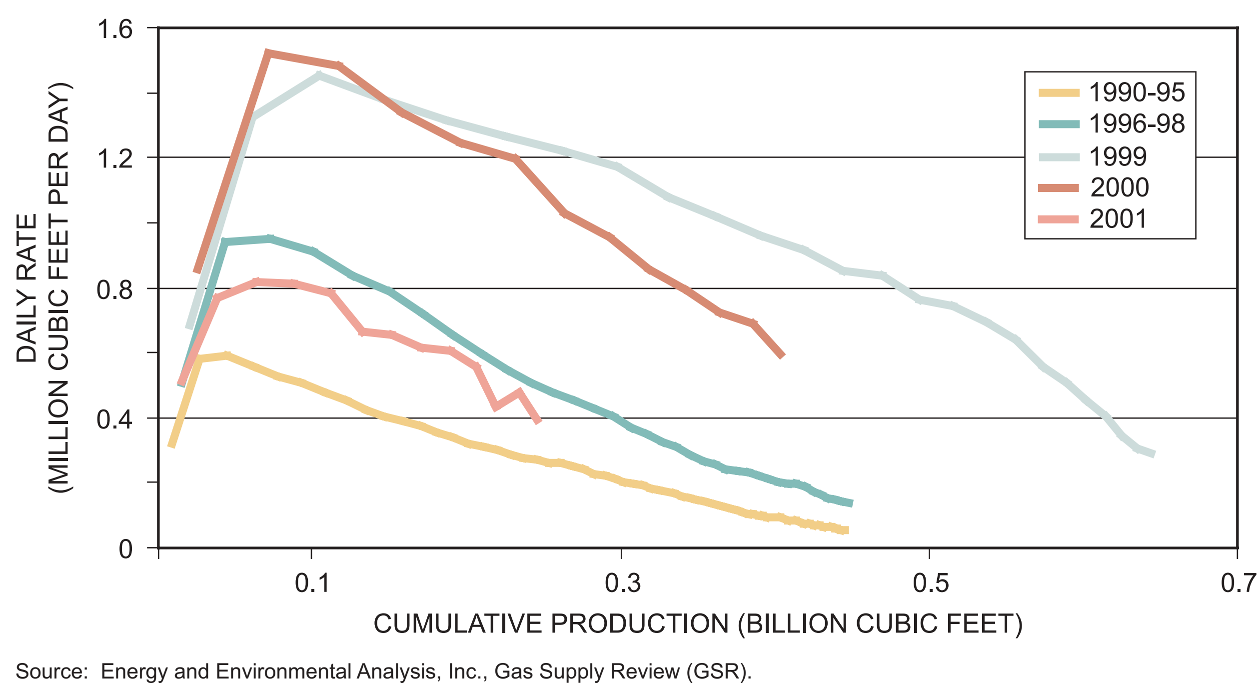


Figure S4-90. Frio Formation – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production

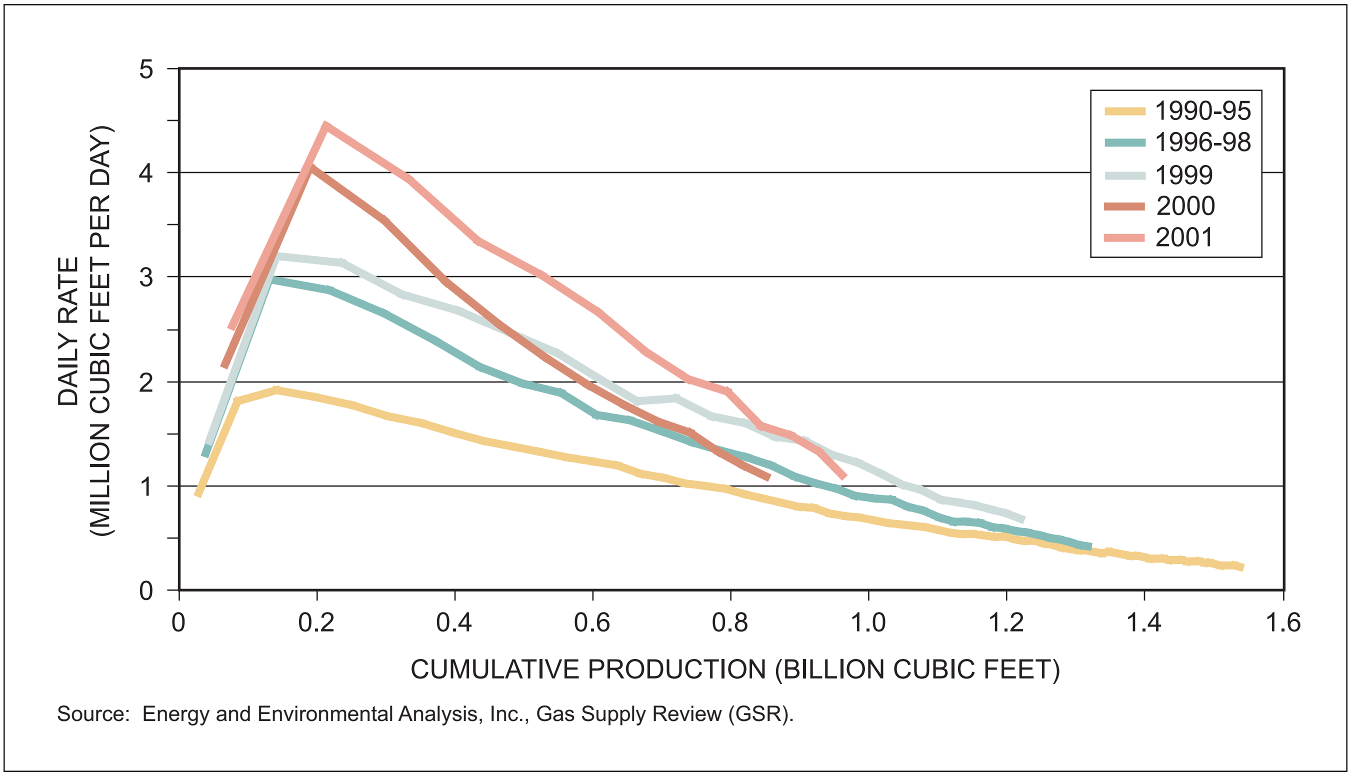


Figure S4-91. Vicksburg Formation – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production

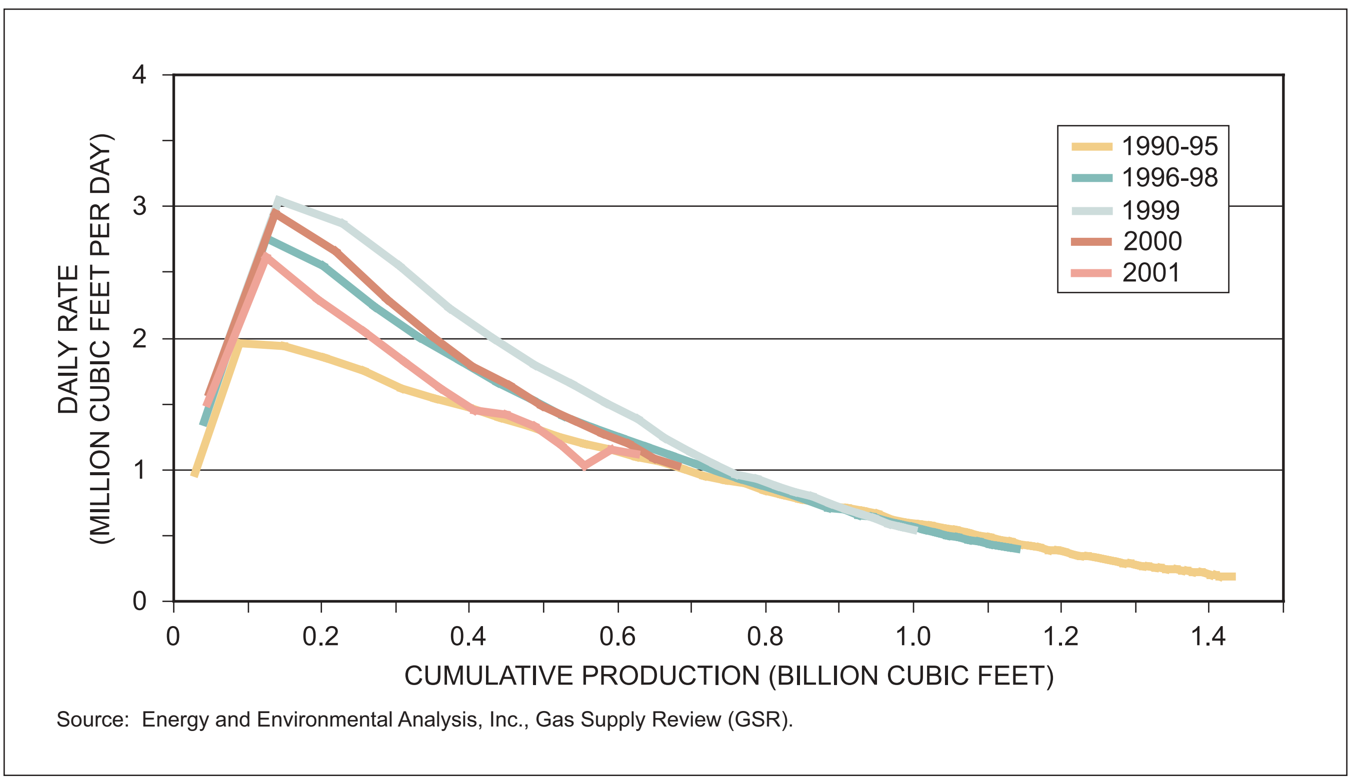


Figure S4-92. Wilcox Formation – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production

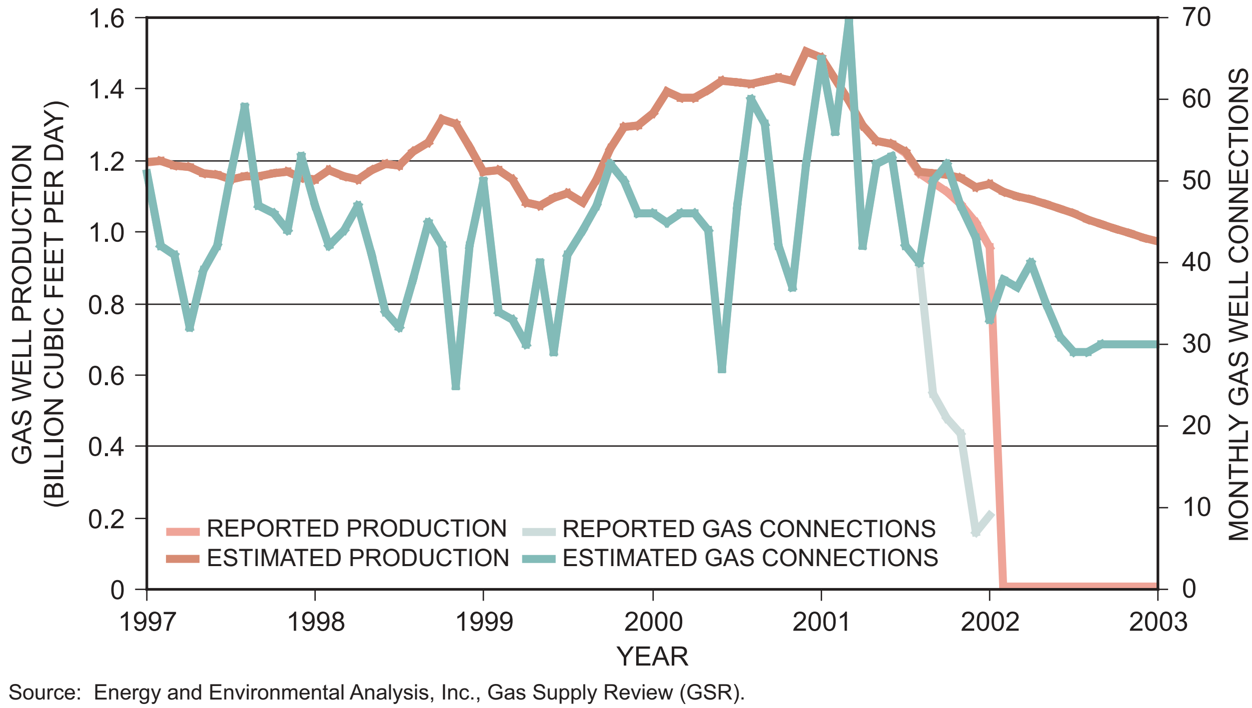


Figure S4-93. Frio Formation – Production and Gas Well Connections

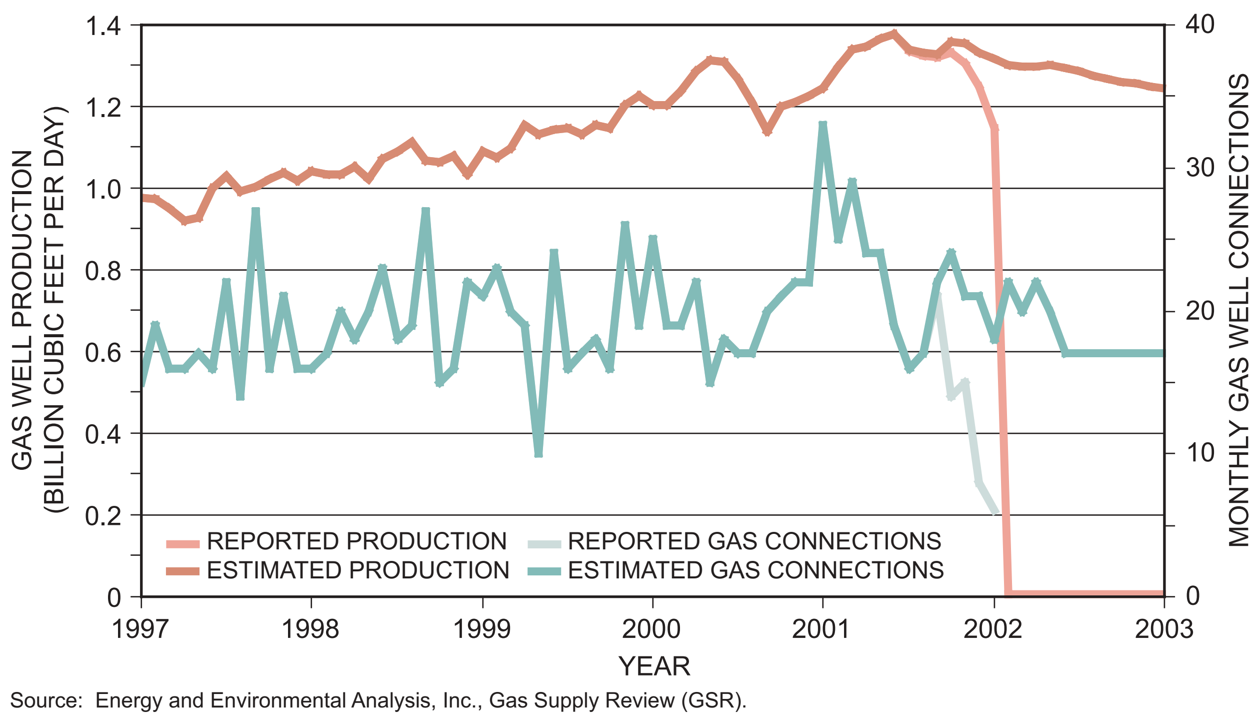


Figure S4-94. Vicksburg Formation – Production and Gas Well Connections

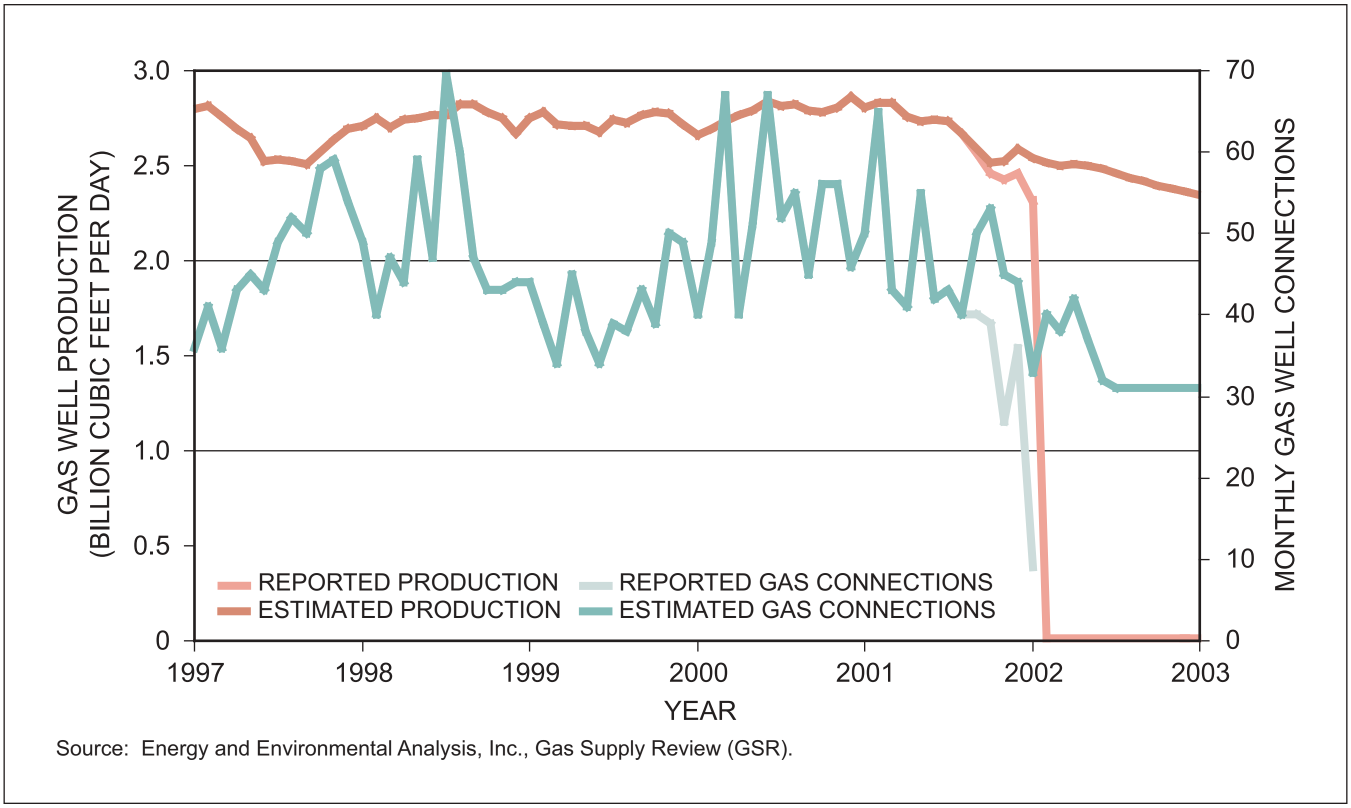


Figure S4-95. Wilcox Formation – Production and Gas Well Connections

required to produce the majority of the reserves has decreased.

5. Seismically, the use of hydrocarbon indicators (HCIs) besides the well known "bright spot" has led to increased exploration success. Pre-stack time migration, pre-stack depth migration, and AVO are all tools that have become readily available to help image deep structures and help locate gas accumulations. The structures in South Texas can be very complicated with many faults. The pre-stack time and depth seismic lead to a higher success rate on both exploratory and development wells.

3. Base Decline

As the industry has been allowed to commingle production from large production intervals, aggressively drilled to the deeper, tighter, and over-pressured parts of the basin, and has more aggressively utilized fracture stimulation technology, it has successfully accelerated per well production in South Texas. However, as EURs have only risen marginally, it has had to accept higher per well decline rates. As these wells have been incrementally added to base production, base decline has increased dramatically in South Texas. In 1990, base production declines were approximately 25%, and the industry needed to replace slightly under 1.5 BCF/D of production to keep production levels flat. By the mid to late 1990s and into the new decade, those figures had climbed to 35-40% and 2.5-3.0 BCF/D of production. (See Figures S4-96 and S4-97.)

4. Reserves

Proved Reserves in South Texas have risen from 15.2 TCF at the beginning of 1997 to 17.2 TCF at the beginning of 2002. Over the same time period, Proved, Producing Reserves have risen, albeit in a much more modest manner, from 11.5 TCF to 11.7 TCF. R/P has also risen, from 5.8 to 7.2 in 2002 (estimated). R/P for Proved, Producing Reserves has risen, also more gradually, from 4.4 to 4.9 (estimated). (See Figure S4-98.)

F. Permian Basin

1. Historical Performance

The Permian Basin contributed approximately 3.8 BCF/D of natural gas production at the end of

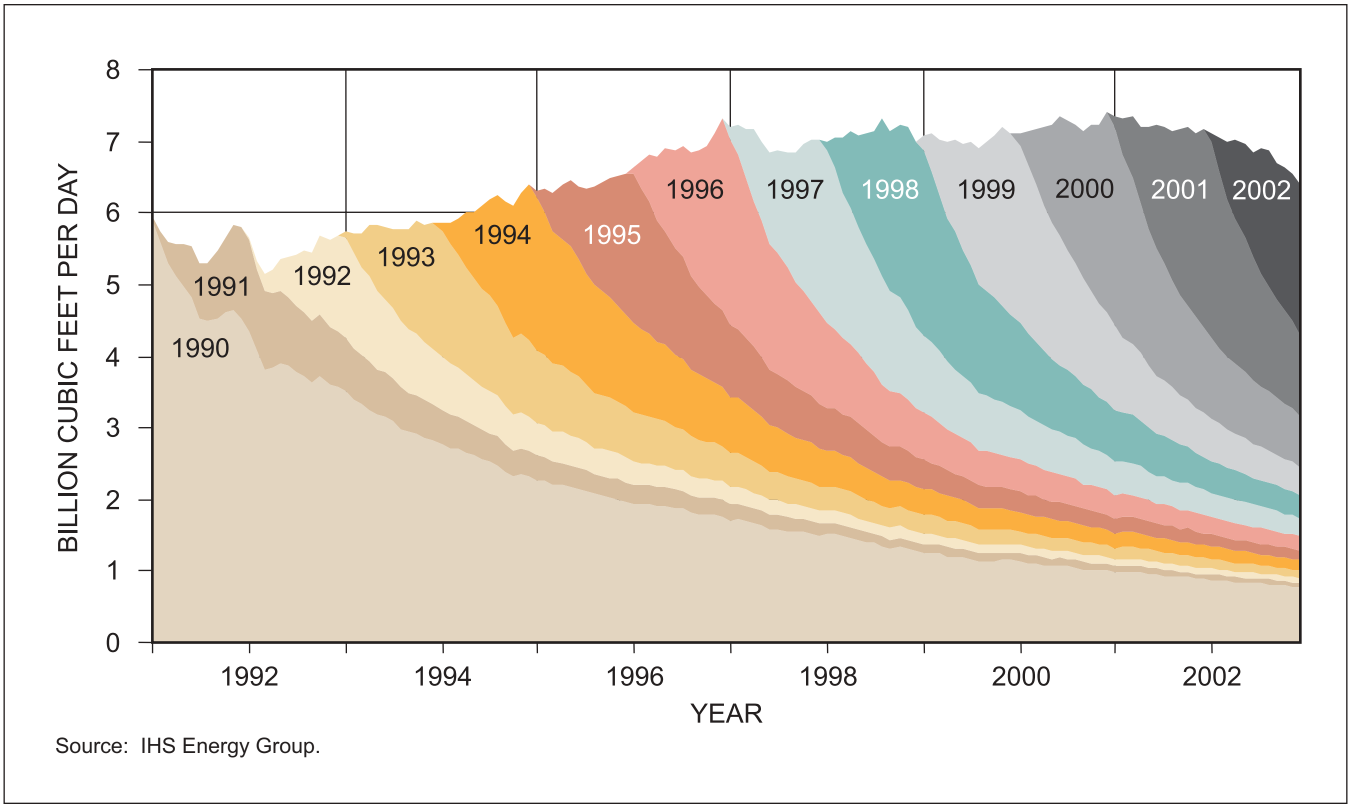


Figure S4-96. South Texas Gulf Coast – Daily Wet Gas Production from Gas Wells, by Year of Production Start

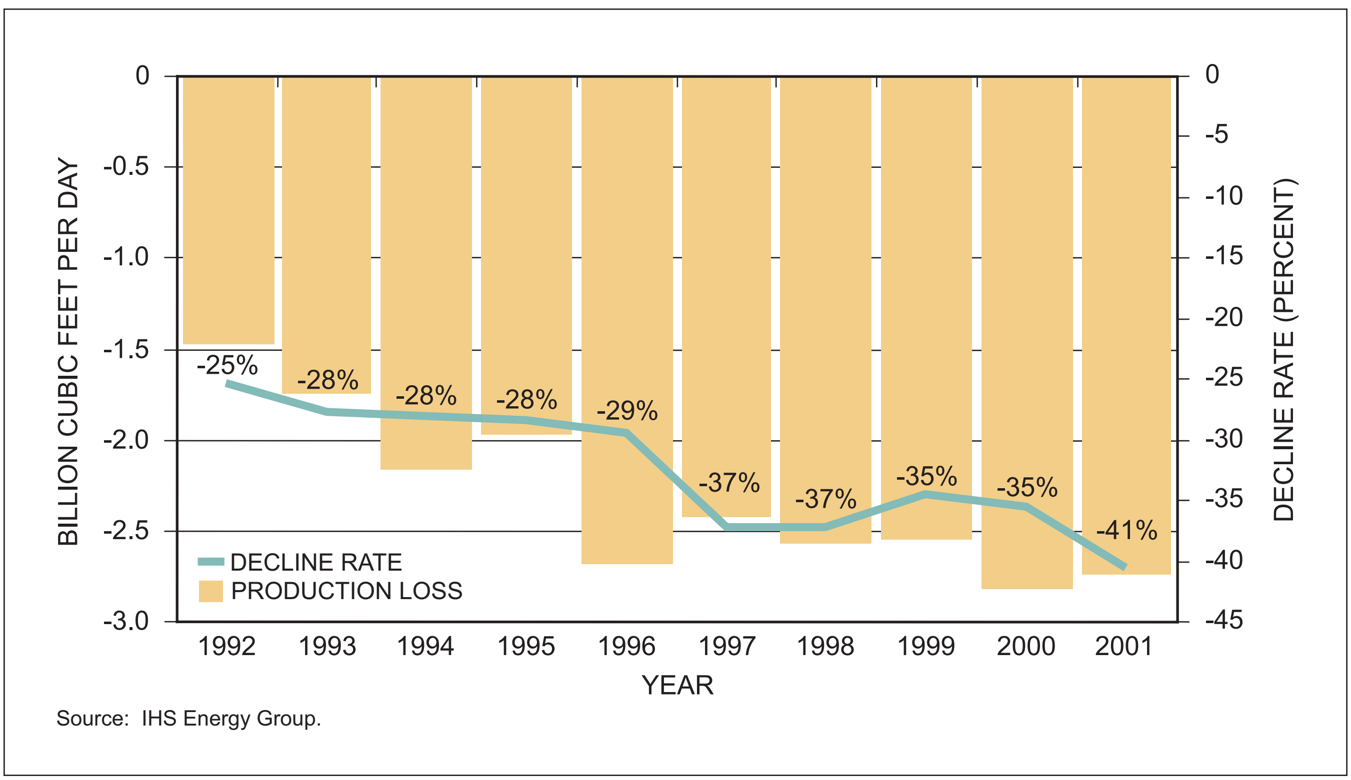


Figure S4-97. South Texas Gulf Coast – Decline Rate of Base Gas Production, if No New Wells had been Drilled, and Equivalent Production Loss

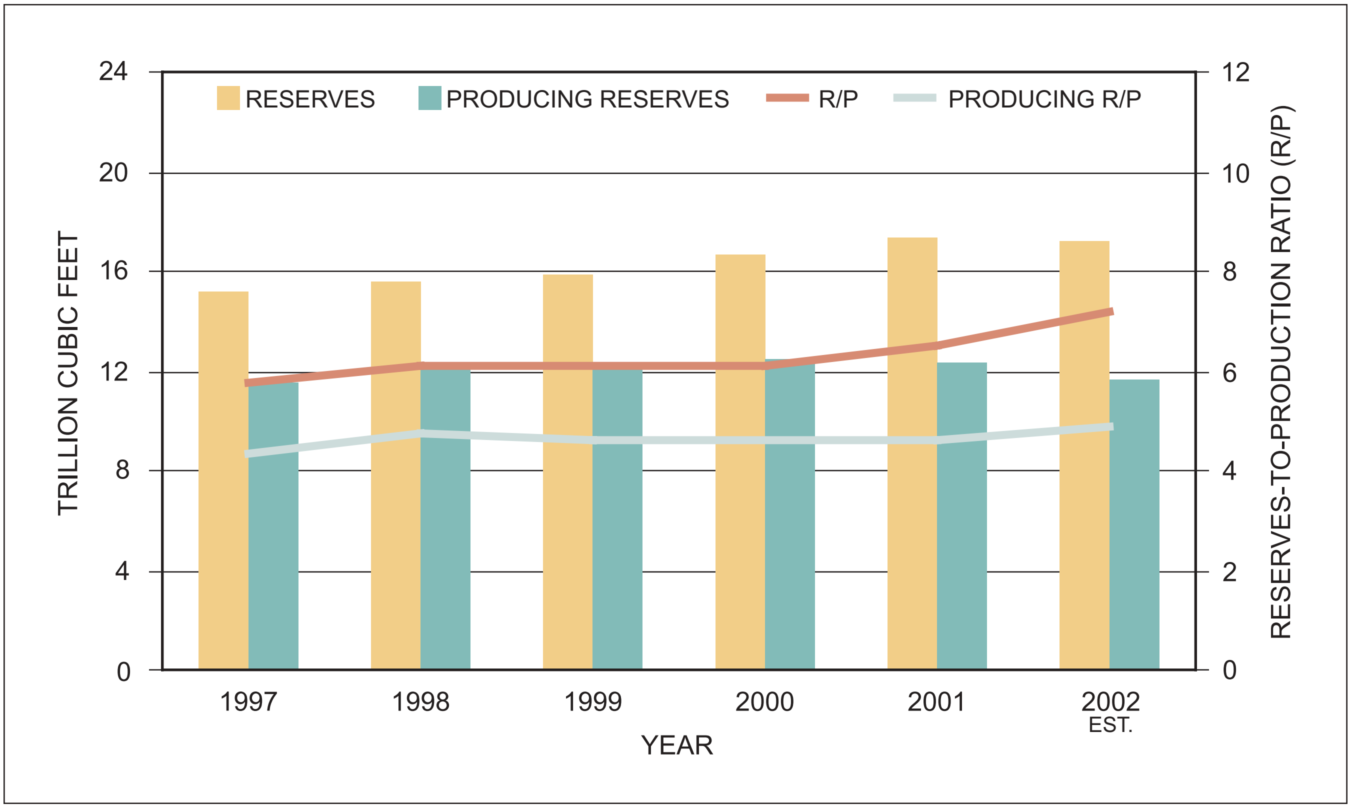


Figure S4-98. South Texas Gulf Coast – Wet Gas Reserves

2002. Production has fallen slowly from 1990, when annual average gas production was of 4.1 BCF/D and peak rates of 4.3 BCF/D. (See Figure S4-99.)

In the early part of the 1990s, rig count and gas well connections stayed fairly constant at about 80 rigs (Texas only) resulting in annual gas well connections of approximately 700. To hold gas production steady in the mid-1990s gas connections increased to approximately 1,150 per year. As gas prices fell in 1999, rig count and gas connections fell back to historical levels of approximately 700 connections per year and gas production fell. Gas connections increased back to 1,000 in 2000 and 1,300 in 2001, which flattened the basin's decline. As connection levels fell back to 1,100 in 2002, the basin again began to experience production declines.

The Permian Basin has a relatively significant proportion of associated gas production which contributes to the stability of overall production. Although the basin is considered mature, it has continued to attract development activity in the form of secondary recovery, horizontal drilling, and down-spacing of wells.

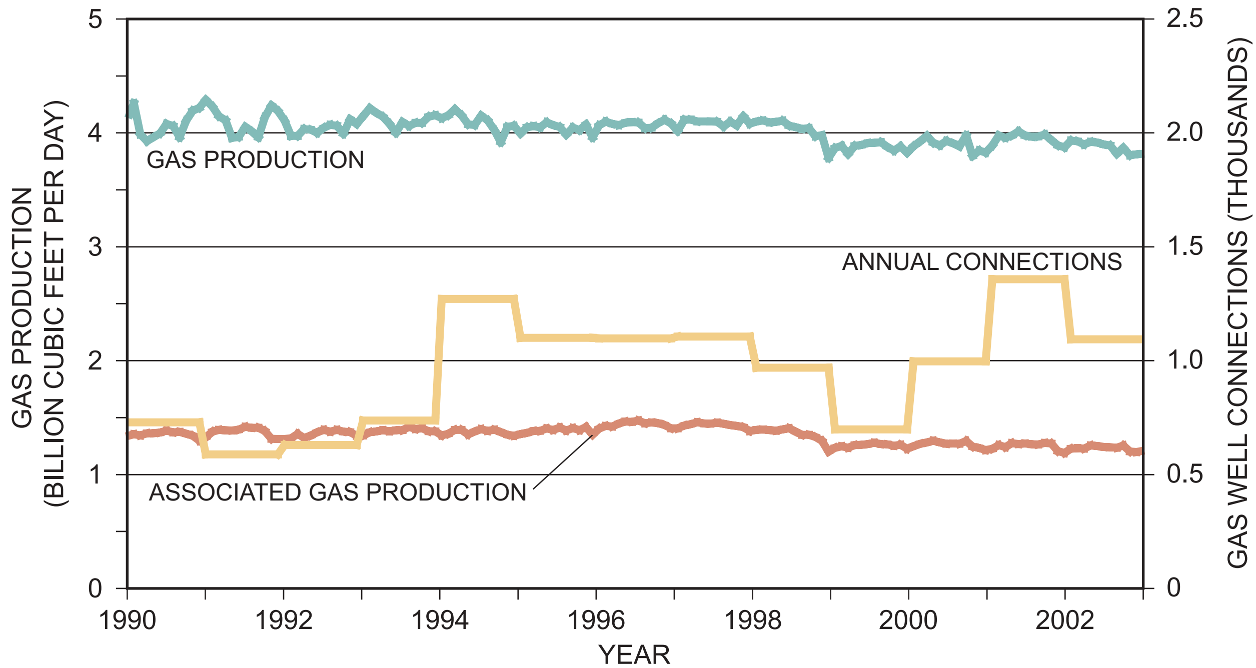
2. Well Performance

Average gas well performance in the Permian Basin was analyzed by vintage. (See Figure S4-100.)

Average EUR per connection, after holding steady in the early part of the decade, increased significantly in 1998, 1999, and 2000. The increase in well productivity in this period coincided with the beginning of horizontal drilling for gas resources in the basin, increasing average well productivity. As in other onshore basins, initial production rates rose during the 1990s, to around 0.85 MMCF/D in 2000 compared to about 0.45 MMCF/D in the early-1990s and 0.7 in the mid-1990s. However, initial decline rates are getting steeper, moving from around 40% to around 50%. (See Figures S4-101 and S4-102.)

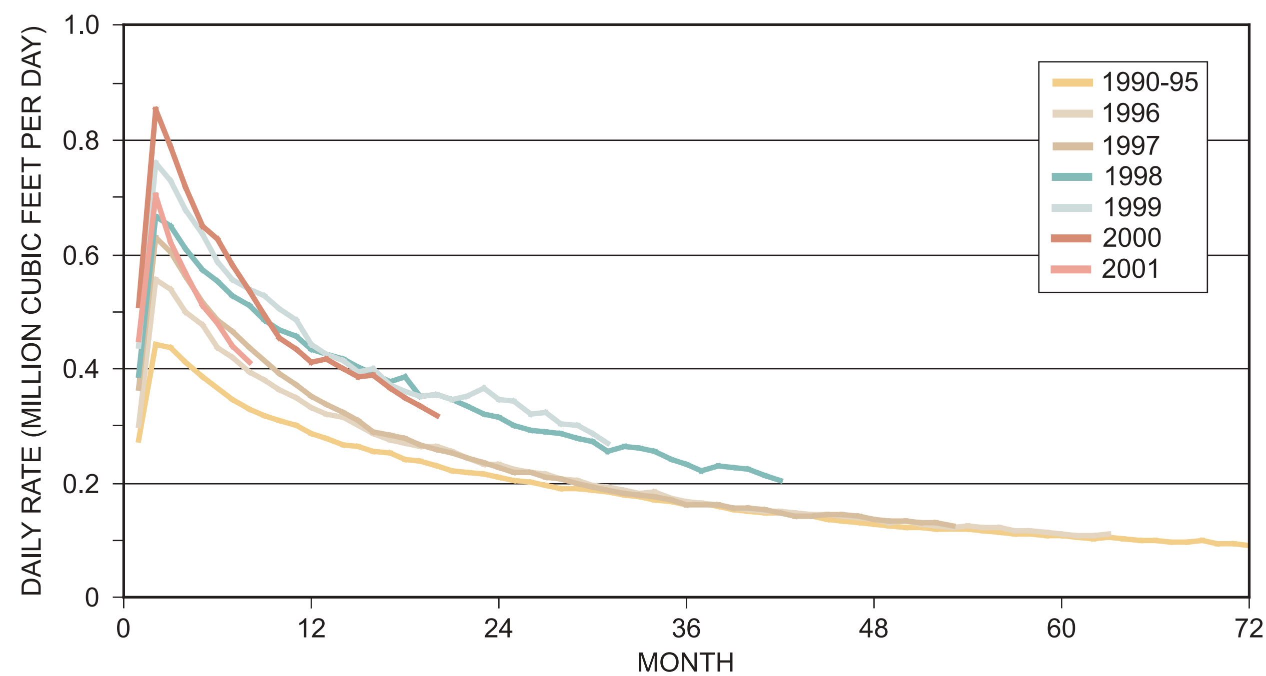
3. Base Decline

The base decline of the basin increased slightly between 1992 and 2001 from approximately 0.4 BCF/D in 1992 to about 0.5 BCF/D by 2001. (See Figures S4-103 and S4-104.)



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-99. Permian Basin – Production and Gas Well Connections



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-100. Permian Basin – Average Daily Gas Well Production vs. Time, by Year of First Production

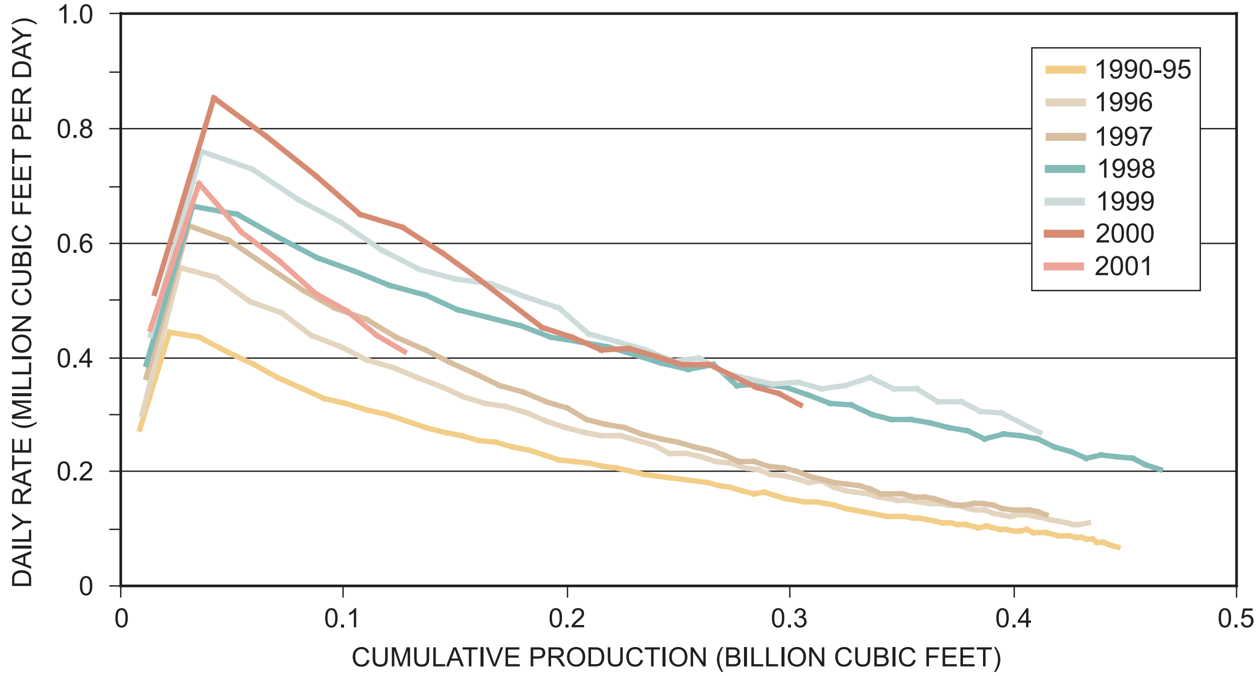


Figure S4-101. Permian Basin – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production

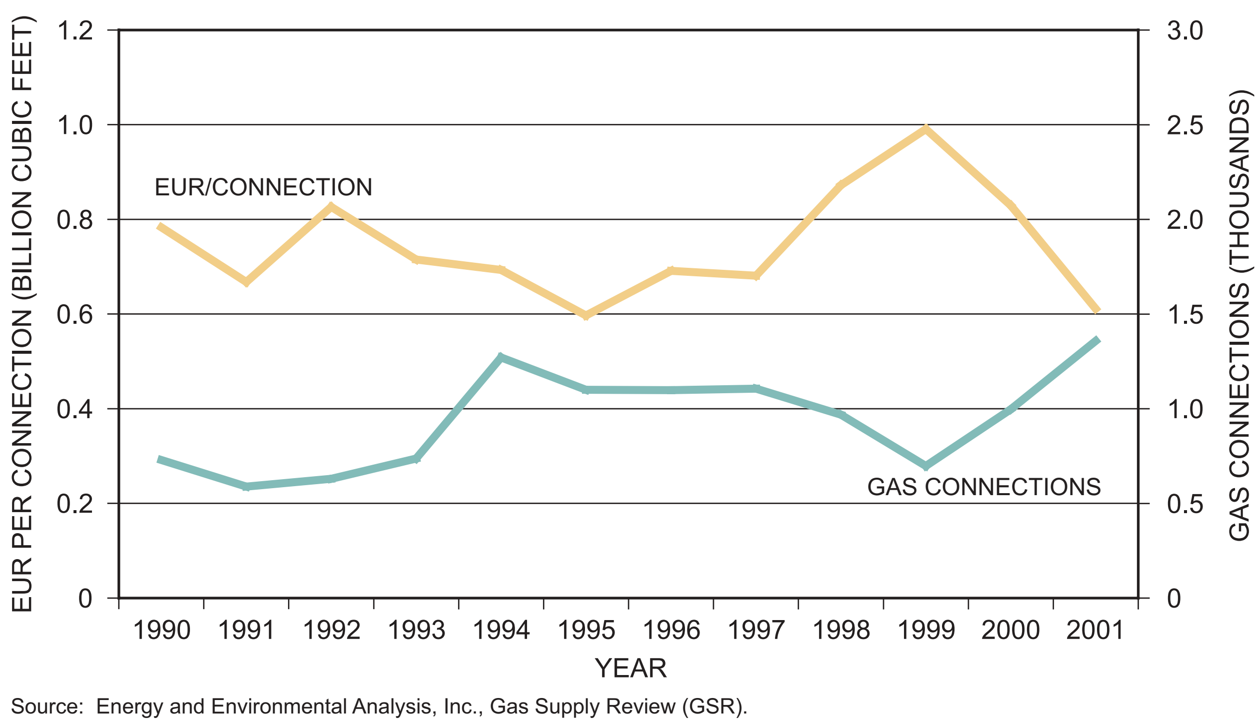


Figure S4-102. Permian Basin – Estimated Ultimate Recovery per Gas Connection

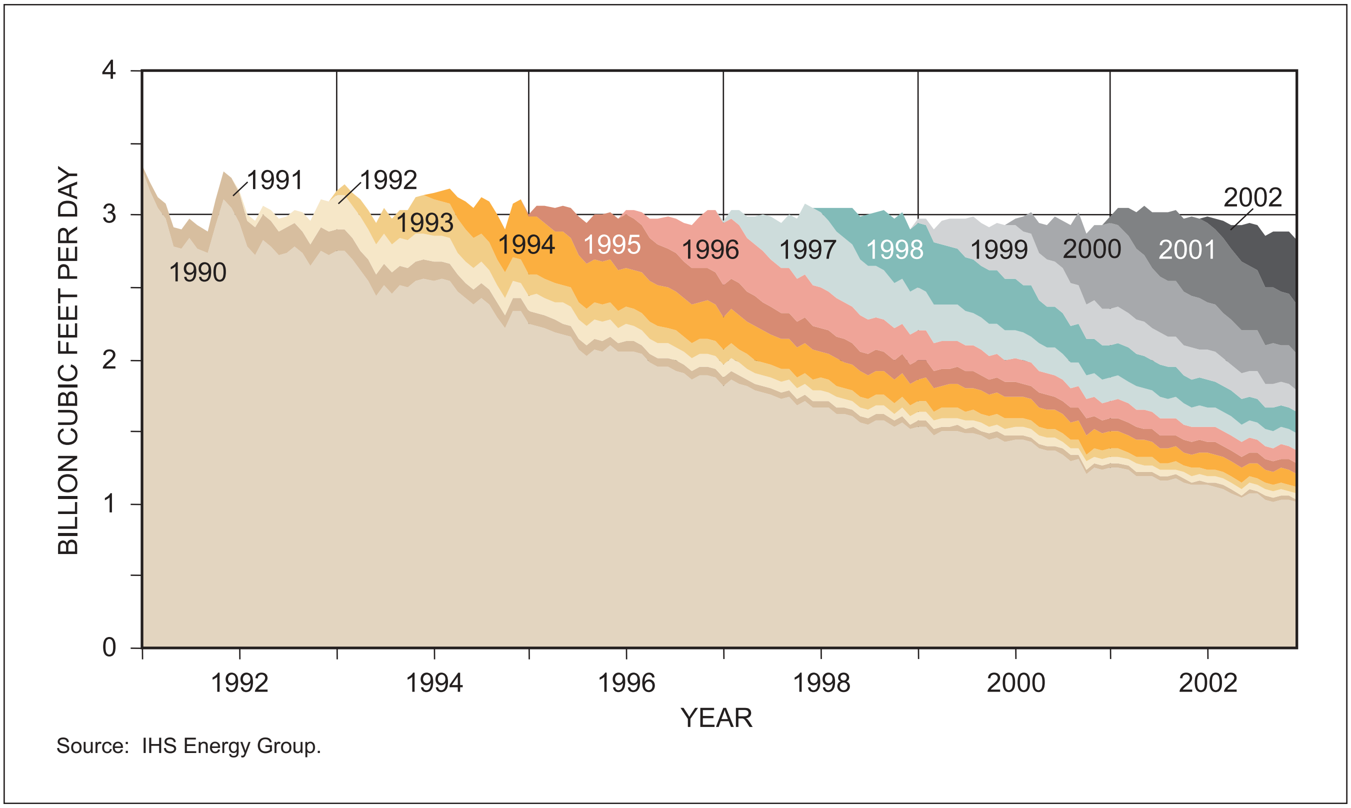


Figure S4-103. Permian Basin – Daily Wet Gas Production from Gas Wells, by Year of Production Start

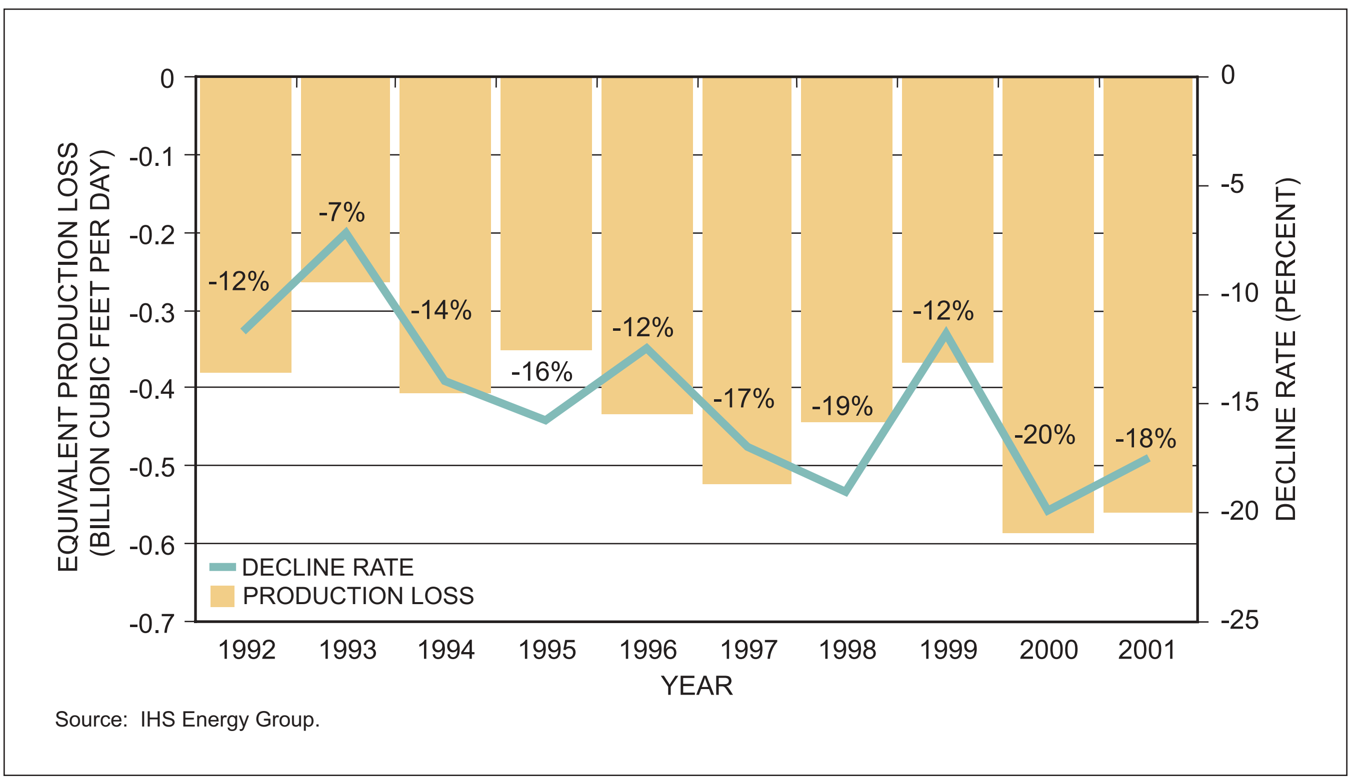


Figure S4-104. Permian Basin – Decline Rate of Base Gas Production if No New Wells had been Drilled, and Equivalent Production Loss

4. Reserves

Permian Basin Proved Reserves have increased from 14.5 TCF in 1997 to 15.5 TCF at the beginning of 2001. Reserves declined in 1998 and 1999. Since 1998, booked reserves have increased steadily, as a function of the higher price environment, increased drilling activity, and higher average well EURs. As a result, the total reserves-to-production ratio has risen to 9.5, above the average for the U.S. lower-48.

A rising proportion of new reserve bookings have been classified as non-producing, implying that additional development capital would need to be spent in order to transform these reserves into marketable gas. As the percentage of Proved Reserves in non-producing reservoirs has increased from 9% to 22%, the reserves-to-production ratio of producing reserves has actually fallen to below 8. (See Figure S4-105.)

G. Midcontinent and Anadarko Basin

1. Historical Performance

The Midcontinent consists of the Anadarko Basin together with a number of other smaller basins stretching from North Texas through Oklahoma and Kansas. Of the Midcontinent region, the Anadarko Basin comprises approximately 75-80% of natural gas production.

At the end of 2002, the Midcontinent was producing a total of 6.4 BCF/D of natural gas. The region has been in steady decline since 1990, when production peak rates totaled just under 10 BCF/D. The long-term trend of steady decline was interrupted in 2000 when increased activity in response to high gas prices flattened the production decline. In the later part of 2001 and 2002, the long-term decline trend resumed as drilling levels fell. (See Figure S4-106.)

This region is generally considered mature, and, as such, would be expected to continue a steady decline, except when periods of unusually high gas prices stimulate a step change in drilling and development activity. Since the region is well-served by pipeline infrastructure to the major markets of the northeast and Midwest, high prices can have a more rapid impact on production levels in this region than in some others such as the Rockies or the offshore.

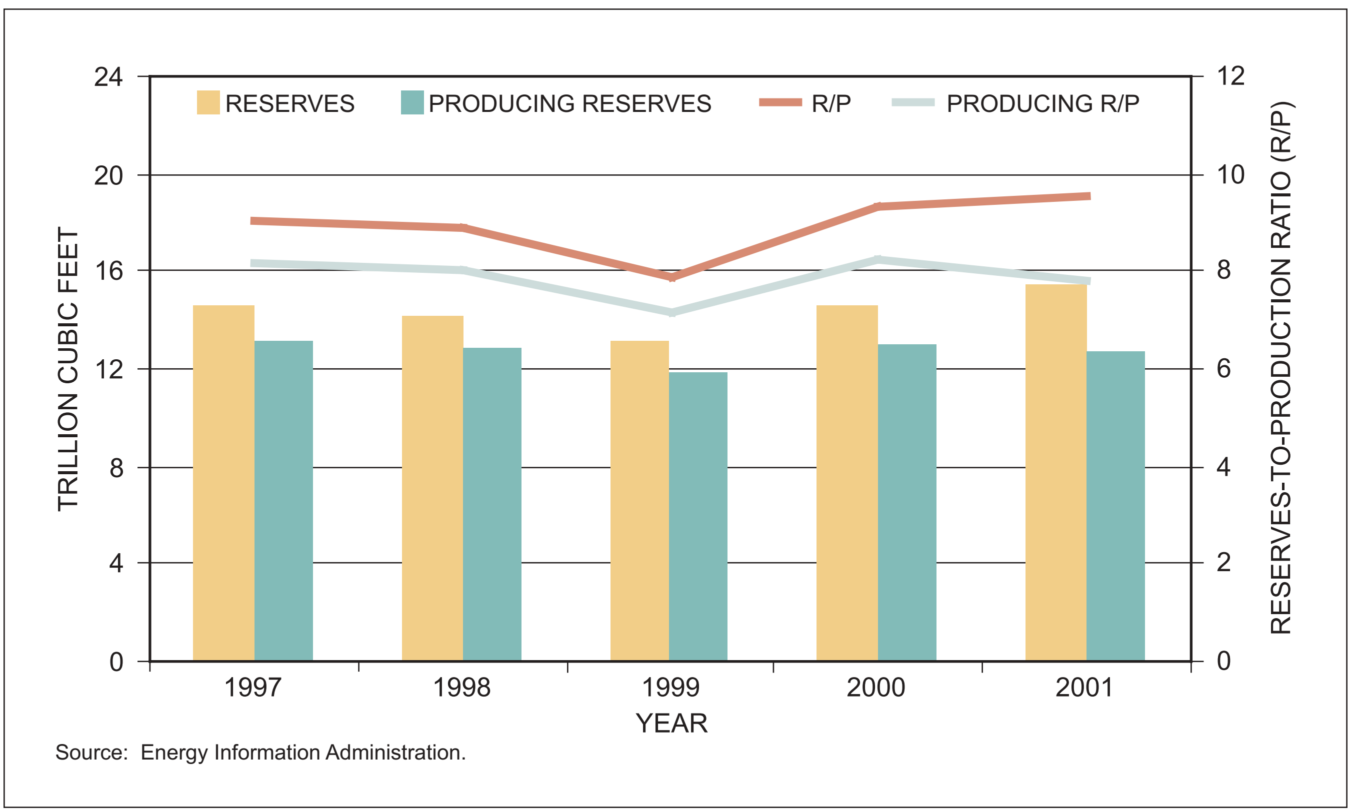


Figure S4-105. Permian Basin – Wet Gas Reserves

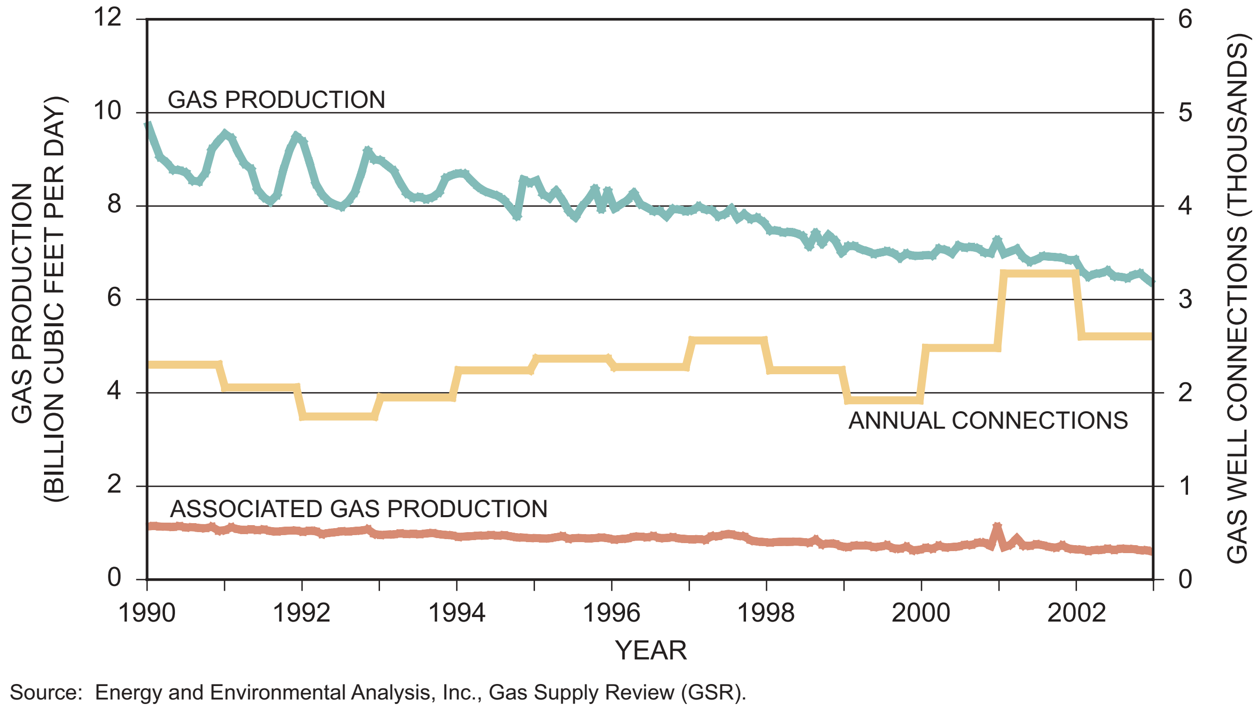


Figure S4-106. Midcontinent – Production and Gas Well Connections

2. Well Performance

Average gas well performance was analyzed by vintage. (See Figure S4-107.)

While average IPs climbed from 0.6 MMCF/D to 0.8 MMCF/D, there has been a steady decline in well EURs, from about 1.4 BCF in 1990 to about 0.7 BCF in 2001. (See Figures S4-108 and S4-109.)

3. Base Decline

Base decline of the Midcontinent has increase from the high teens in the early part of the decade to 20-25% later on in the decade. The decline represented about 1.6-1.9 BCF/D in early 1990s and has stayed near constant even as production has fallen. (See Figures S4-110 and S4-111.)

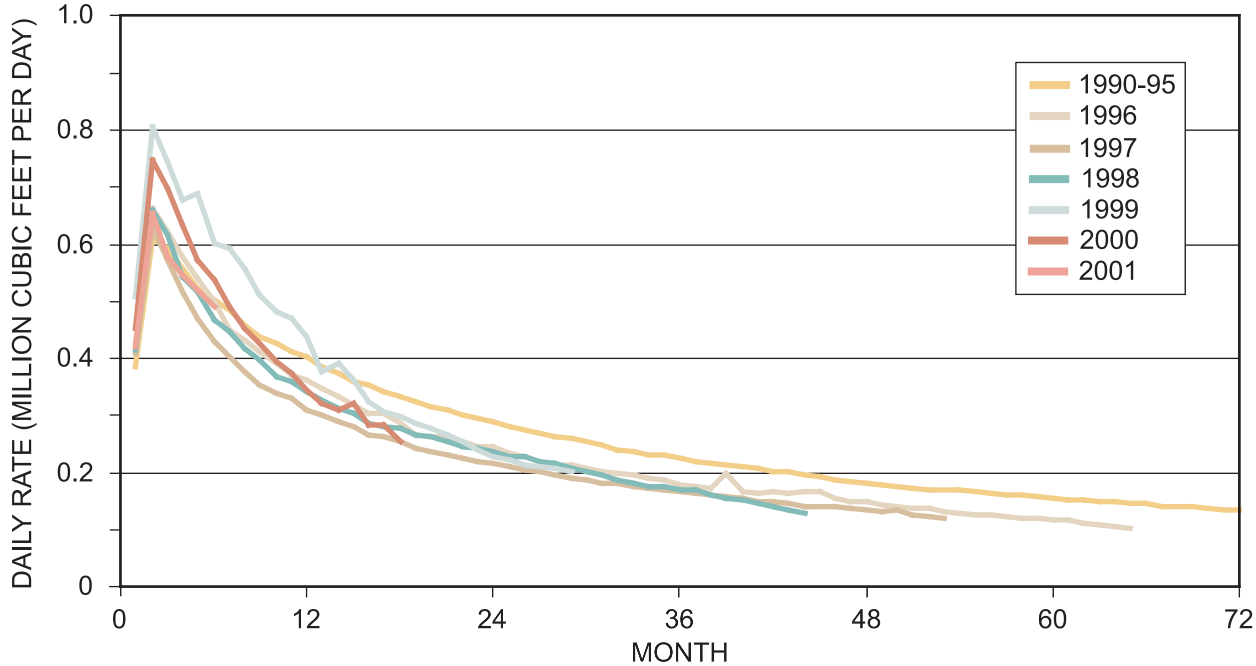
4. Reserves

Proved Reserves in the Midcontinent region have fallen from 28 TCF in 1997 to just under 26 TCF at the beginning of 2001. (See Figure S4-112.)

H. Rocky Mountain Region

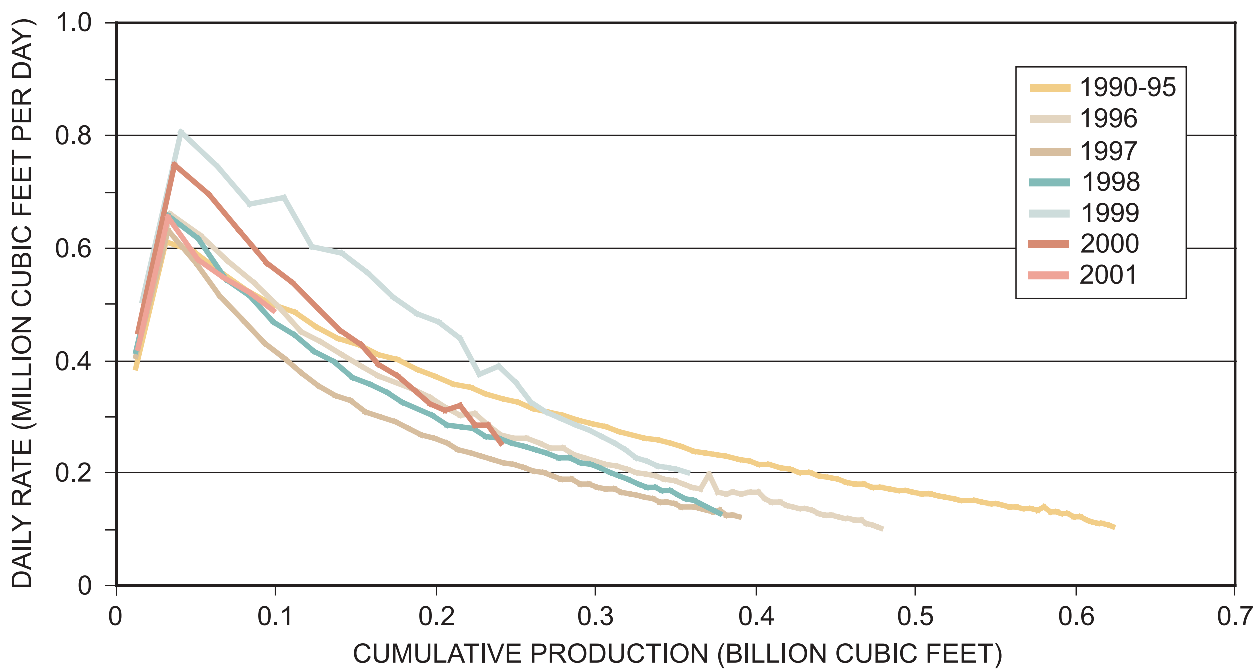
1. Historical Performance

Gas production from the Rocky Mountains, including Wyoming, Colorado, New Mexico, Utah, and Montana has been growing since the early 1980s. At the end of 2002, production from the Rockies was 10 BCF/D. Gas production and gas connections rose rapidly in the early 1990s, partially in response to the Section 29 Tax Credit on tight gas, coal bed methane, and other nonconventional gas production. Connection levels fell by almost 50% in the middle part of the decade as new drilling no longer qualified for the Tax Credit and insufficient pipeline take-away capacity constrained gas exports from the region, leading to significant price differentials for gas in the Rocky Mountains. Since 1999, activity in the Rockies has increased dramatically, with the number of drilling rigs rising from 80 to more than 150 and gas well completions rising from about 2,400 per year to over 6,000. In addition to insufficient export pipeline capacity, Rockies production growth has been impeded by restricted access and regulatory delays. (See Figures S4-113 and S4-114.)



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-107. Anadarko Basin – Average Daily Gas Well Production vs. Time, by Year of First Production



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-108. Anadarko Basin – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production

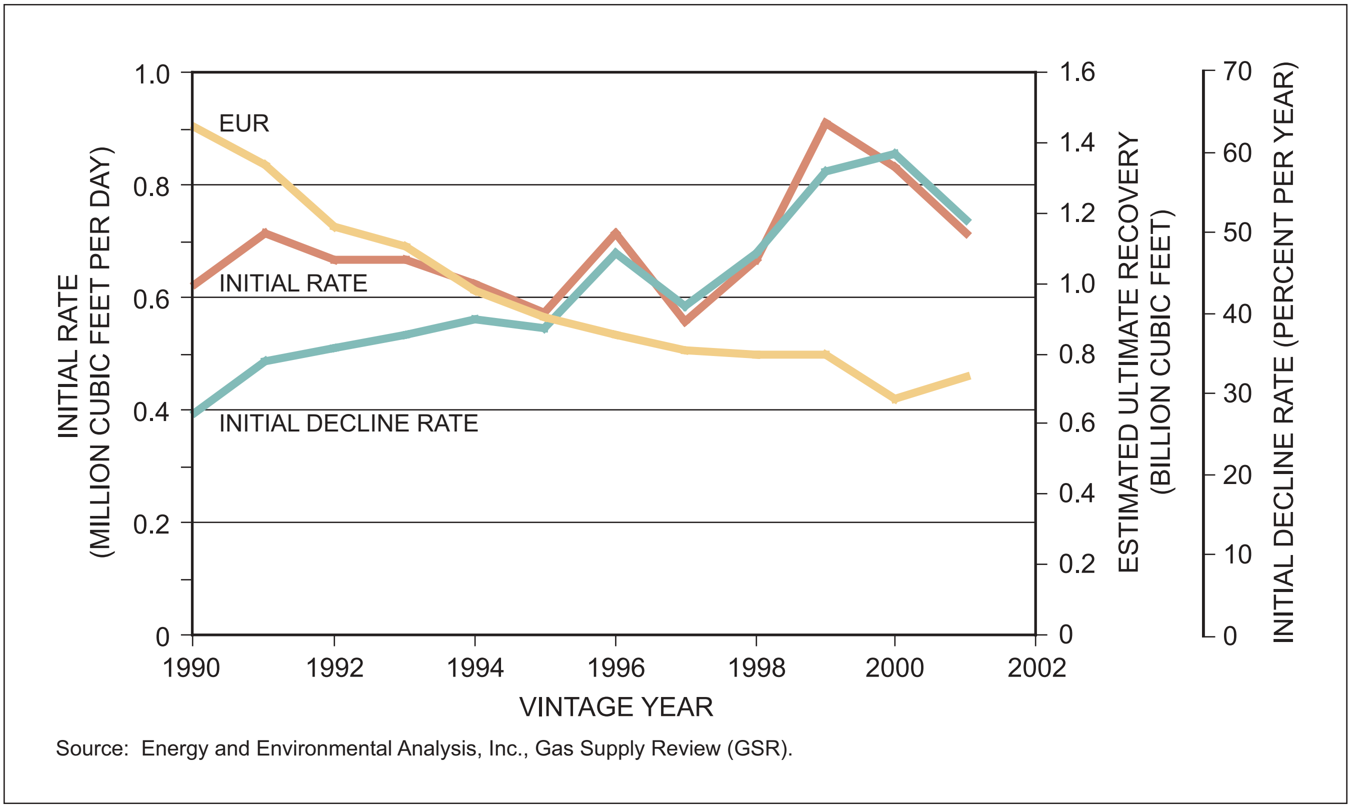


Figure S4-109. Anadarko Basin – Production Performance Trends

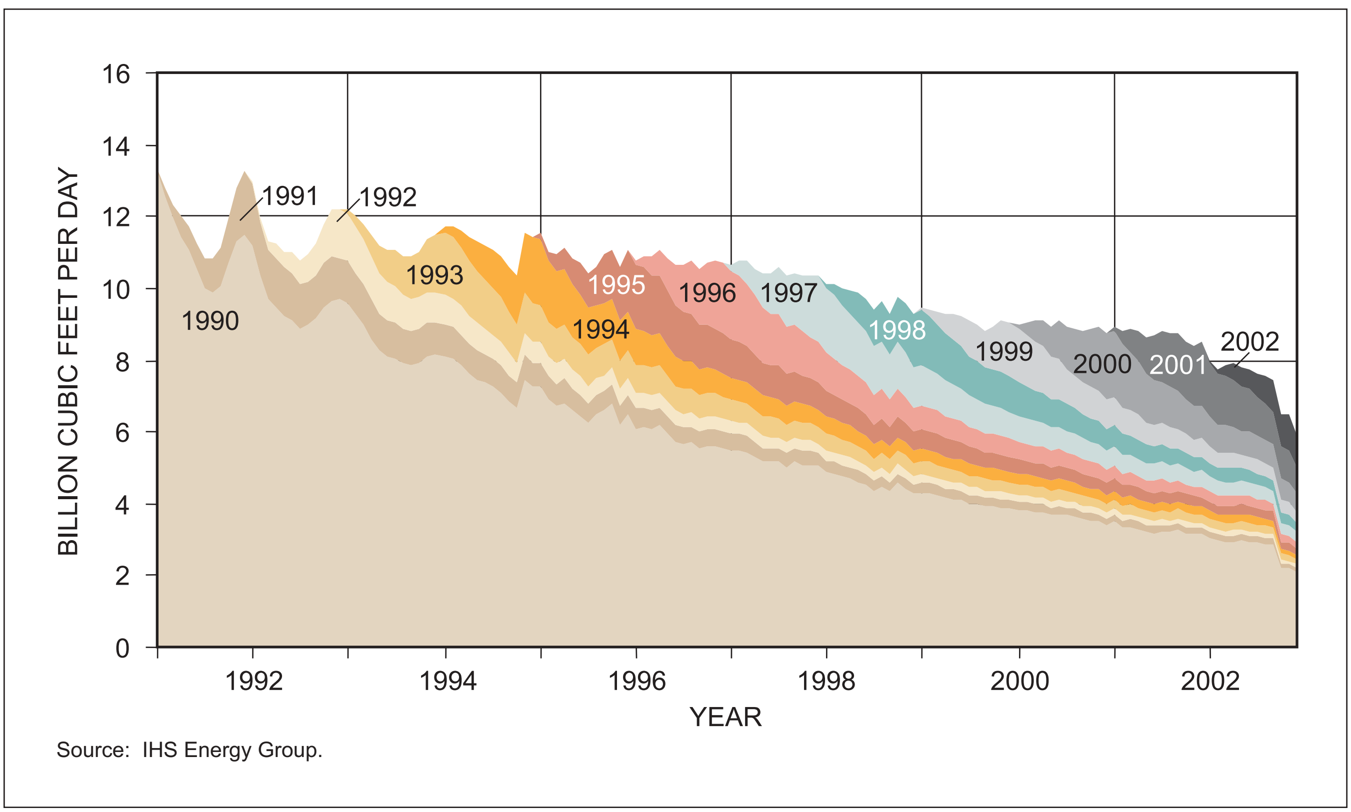


Figure S4-110. Midcontinent – Daily Wet Gas Production from Gas Wells, by Year of Production Start

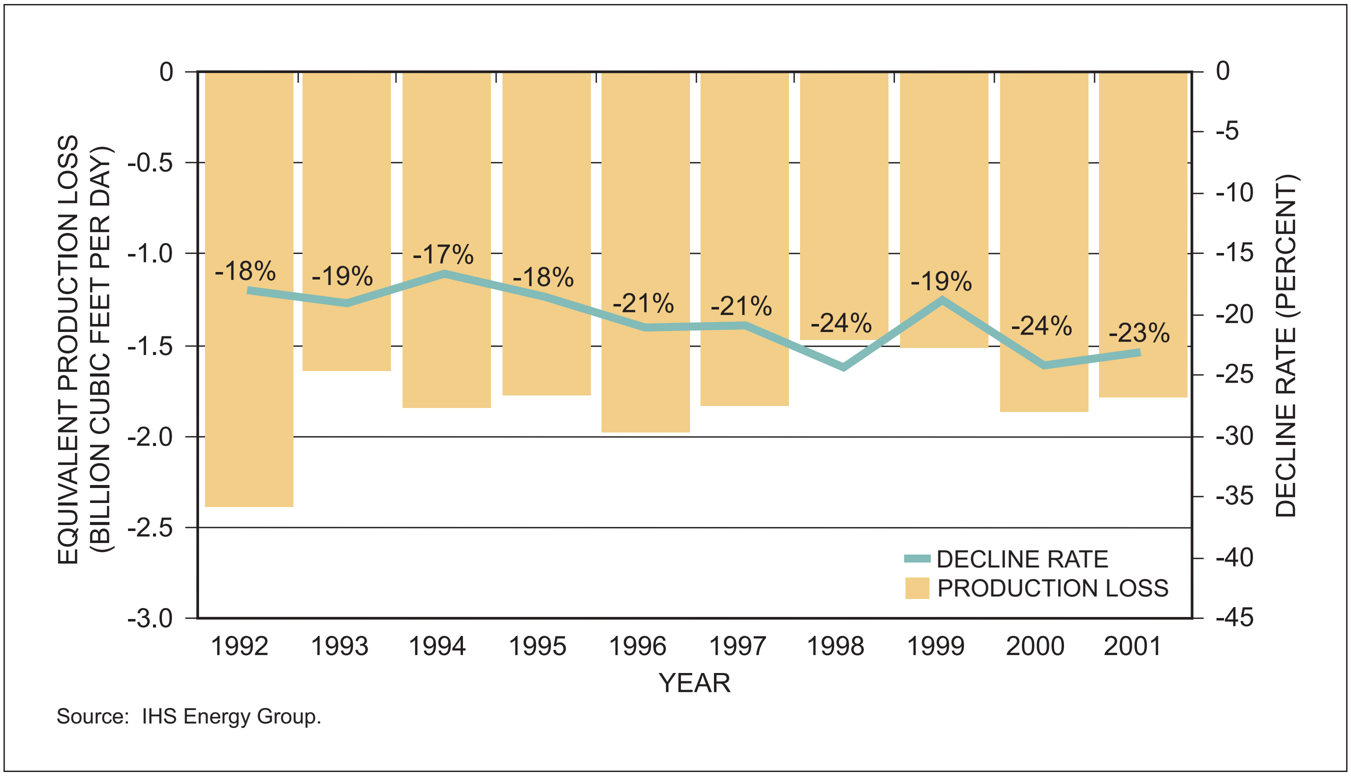


Figure S4-111. Midcontinent – Decline Rate of Base Gas Production if No New Wells had been Drilled, and Equivalent Production Loss

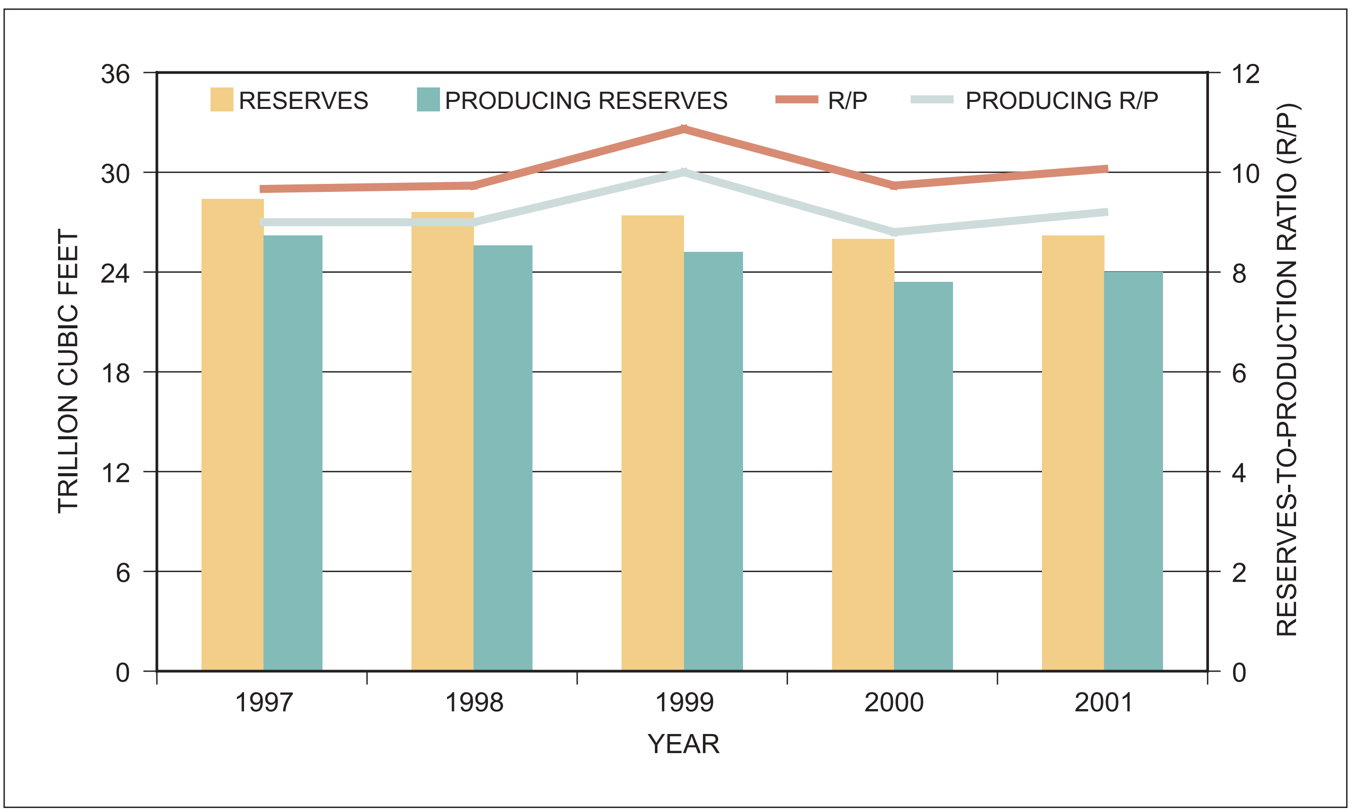


Figure S4-112. Midcontinent – Wet Gas Reserves

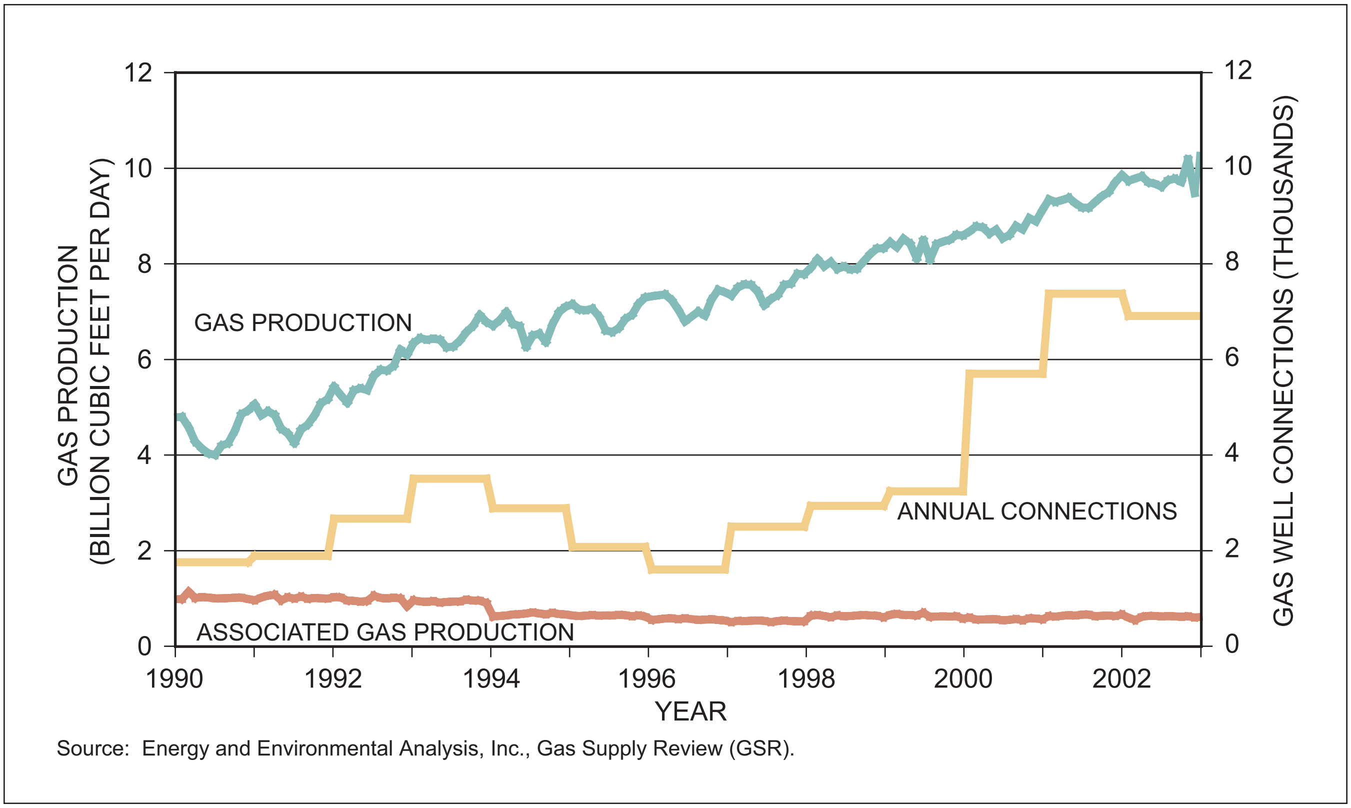


Figure S4-113. Rocky Mountains – Production and Gas Well Connections

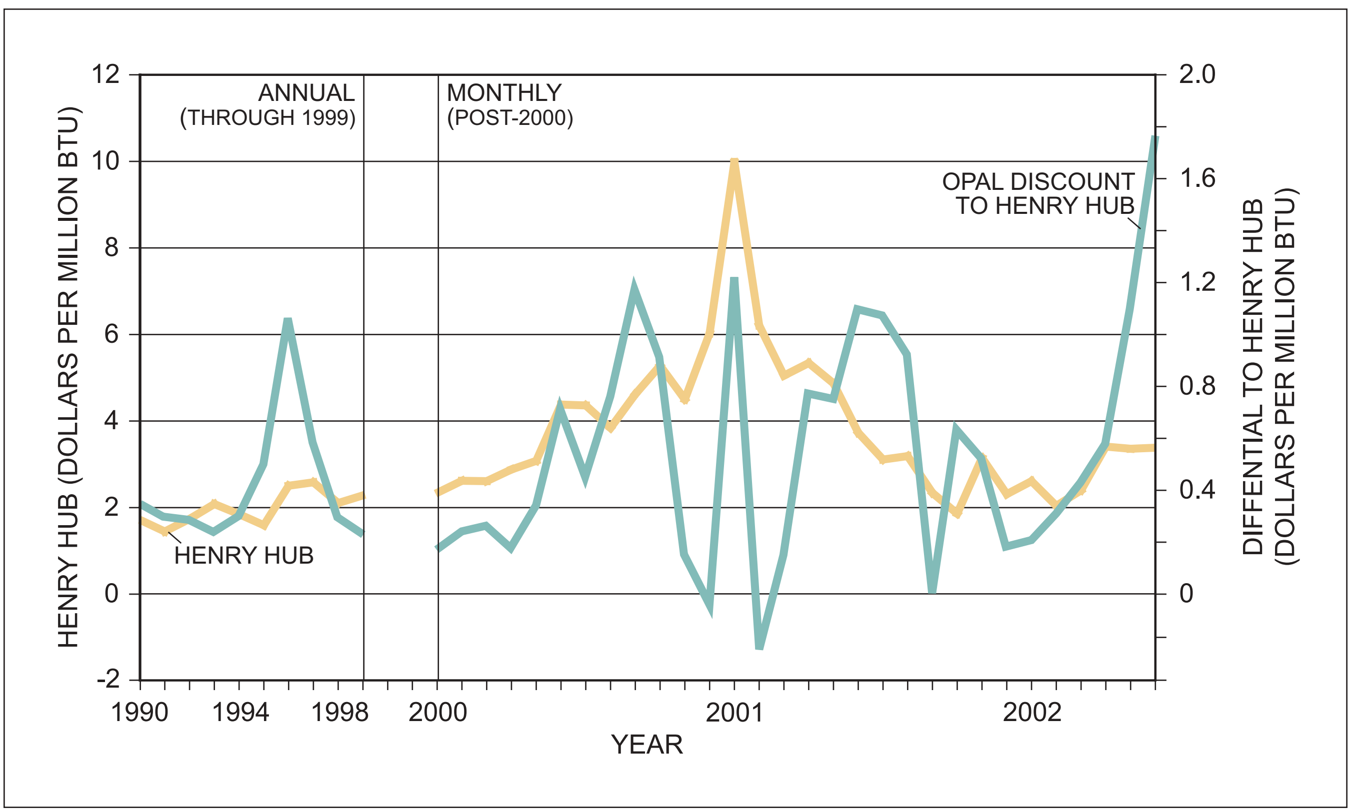
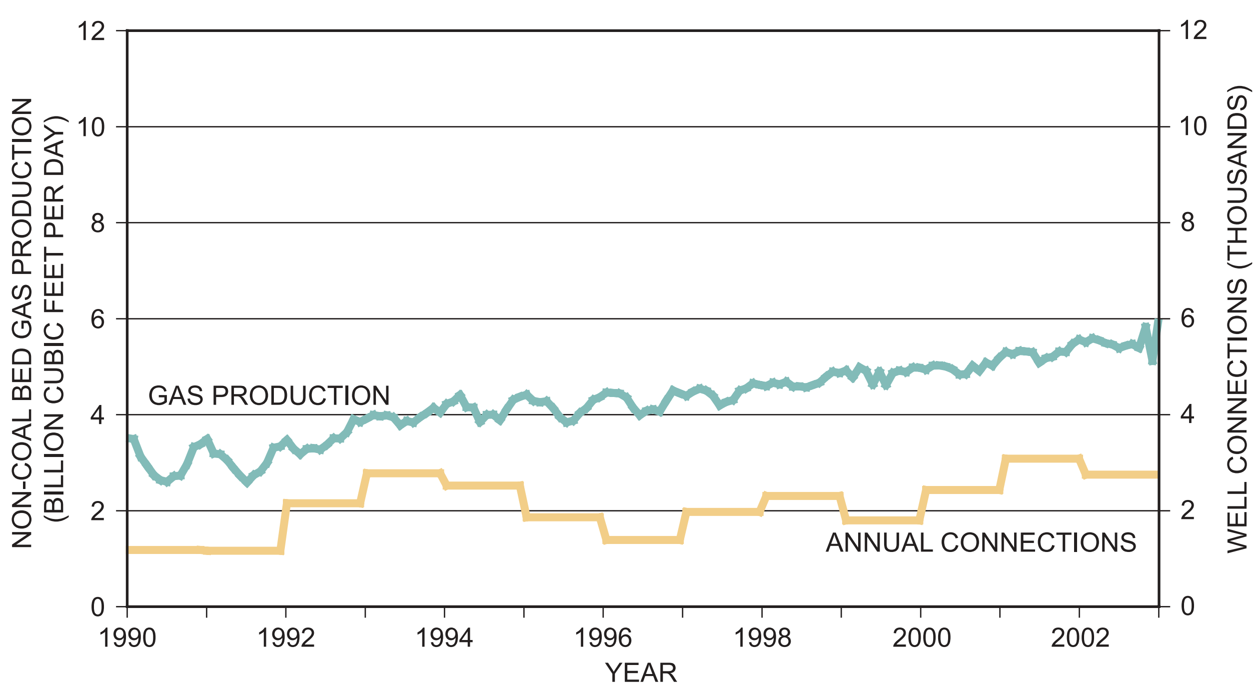


Figure S4-114. Rocky Mountains – (Opal) Hub Prices vs. Henry Hub

Because of different characteristics, conventional/tight gas production was analyzed separately from coal bed methane production. Conventional/tight gas production has increased from an average of 3.0 BCF/D in 1990 to approximately 5.5 BCF/D at the end of 2002. After flattening in the mid-1990s, conventional/tight gas production has increased by 1 BCF/D between 1999 and the end of 2002 on increasing tight gas production, concentrated at the Jonah Field and Pinedale Anticline in the Green River Basin. New well completion/stimulation technology, in which thousands of feet of well bore is opened, stimulated, and produced, has led to an increase in tight gas activity and production. The trend is toward more fracture stages per well (approaching 20) and tighter well spacing (some tests to 20 and even 10 acre spacing). This yields higher initial rates (in some cases over 10 MMCF/D) and larger field EUR estimates. Activity peaked at almost 3,100 connections in 2001. (See Figure S4-115.)

Coal bed methane production in the Rocky Mountains has increased even more robustly, from 0.3 BCF/D in 1990 to approximately 3.8 BCF/D currently. Early 1990s Rocky Mountain coal bed production was dominated by production from the highly prolific (3-5 BCF/connection wells) Fruitland Fairway of the San Juan Basin. Helped initially by the Section 29 Tax Credits, coal bed production climbed rapidly, from 0.3 BCF/D in 1990 to more than 2.0 BCF/D by the end of 1994, from the initial development phase of the San Juan Basin coals. Activity levels slowed in the mid-1990s upon the expiration of the tax credit and low Rocky Mountain gas prices, and turned to more in-fill type drilling. The number of coal bed gas connections fell from 600-700 in the early part of the decade to a little over 200 in 1995 and 1996. EURs fell rather dramatically but production from the basin continued to rise due to the unique production profile of coal bed production. (See Figure S4-116.)

The focus of coal bed activity switched to the Powder River Basin and to a lesser extent the Raton Basin in the late 1990s as the San Juan Basin matured. Connections in the Fruitland Coal, which numbered over 600 in 1991, were averaging 180 in the late 1990s and early part of the 2000s. In contrast, coal bed methane connections in the Powder River Basin, have grown twelve-fold, from 250 in 1997 to over 3,000 in 2001. While the Powder River coal bed methane has much lower EURs (0.2-0.4 BCF/connection) than the Fruitland, production comes from much shallower depths, generally less than 750 feet deep, versus 2,500



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-115. Rocky Mountains – Non-Coal Bed Gas Well Gas Production and Well Connections

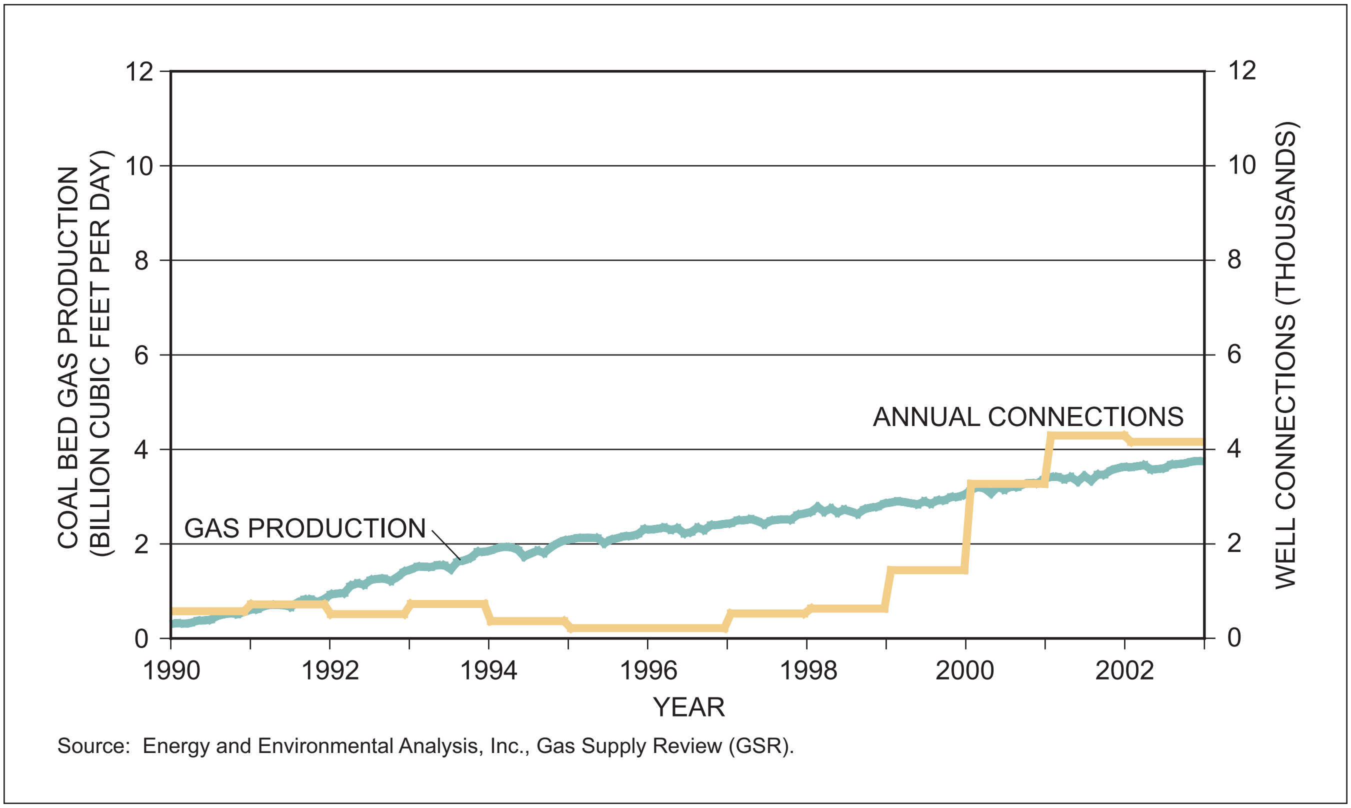


Figure S4-116. Rocky Mountains – Coal Bed Methane Gas Production and Well Connections

feet deep in the San Juan Basin. (See Figures S4-117 and S4-118.)

The San Juan Basin, the largest producing basin in the Rockies, rose marginally over the period 1997-2001, from 3.9 BCF/D to 4.1 BCF/D. The next largest producing basin, the Green River Basin, rose from 2.0 BCF/D to 2.5 BCF/D on growing tight gas production. The largest increase in production came from the coal bed methane production in the Powder River Basin, which accounted for 0.9 BCF/D of overall Rockies growth. The Wind River, Uinta, Denver, and Piceance Basins all recorded increases in production, while production from the Overthrust Belt fell. (See Figures S4-119 and S4-120.)

2. Well Performance

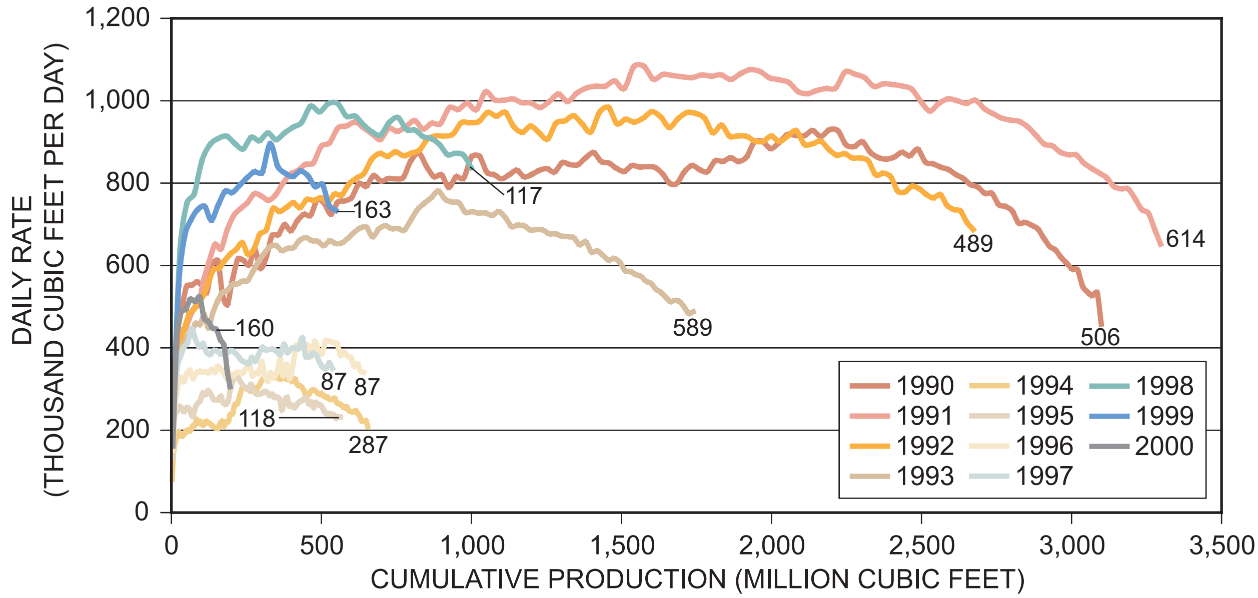
Coal bed methane and non-coal bed methane gas wells were analyzed by vintage. (See Figures S4-121 and S4-122.)

Rockies' well deliverability has been improving over the last decade, with average non-coal bed wells achieving higher peak rates and maintaining roughly the same decline. In the first twelve months of production, the average Rockies non-coal bed gas well will decline by about 60%, and thereafter decline hyperbolically at a shallower rate.

Non-coal bed methane EUR per connection has been steadily increasing to 1.2 BCF/connection in 2001, in part driven by technology increases in drilling and well stimulation techniques. For coal bed methane wells, average EUR per well has been declining, reflecting the lower well quality of the Powder River vis-a-vis the San Juan Basin. (See Figures S4-123, S4-124, and S4-125.)

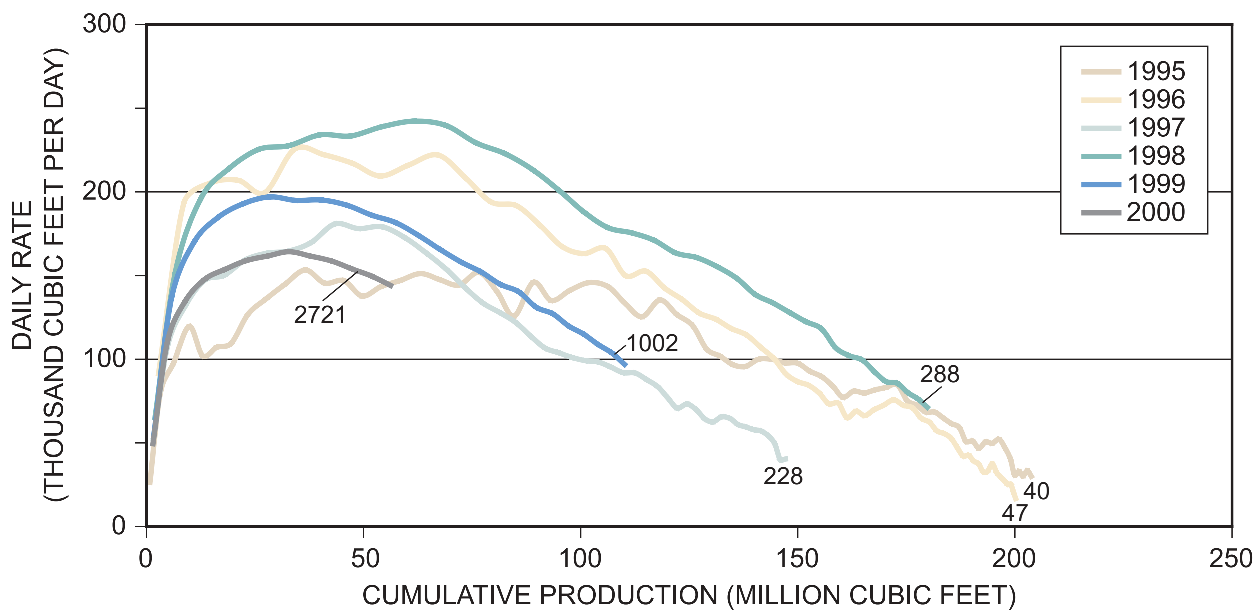
3. Base Decline

Base decline rates in the Rocky Mountains region were very shallow in the early 1990s as (1) gas export was constrained by insufficient pipeline capacity and wells were commonly shut-in or reduced in summer months, and (2) coal bed methane production with its slow decline well profile, was rapidly becoming a significant percentage of Rockies gas production. In 1992, production would have actually grown despite halting activity. As take-away infrastructure reduced summer shut-in the later part of the 1990s, decline



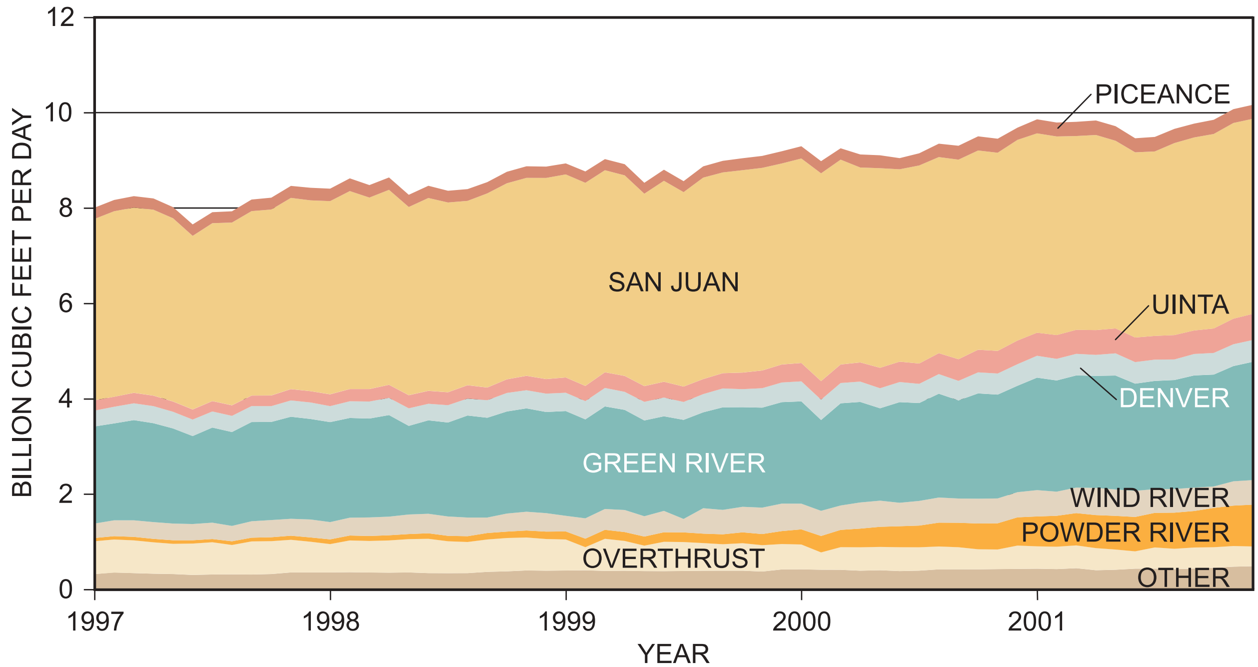
Note: Numbers in body of graphic are number of wells brought on to production during that year.
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-117. San Juan Basin Coal Bed Methane Wells – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production



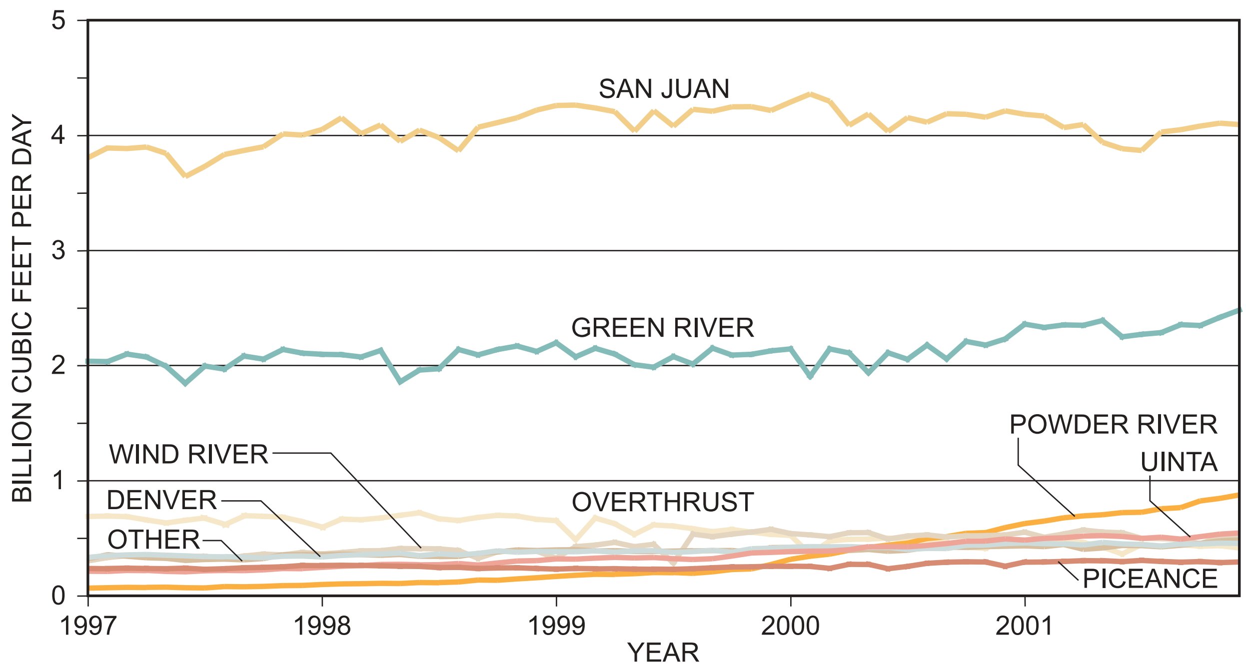
Note: Numbers in body of graphic are number of wells brought on to production during that year.
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-118. Powder River Basin Coal Bed Methane Wells – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production



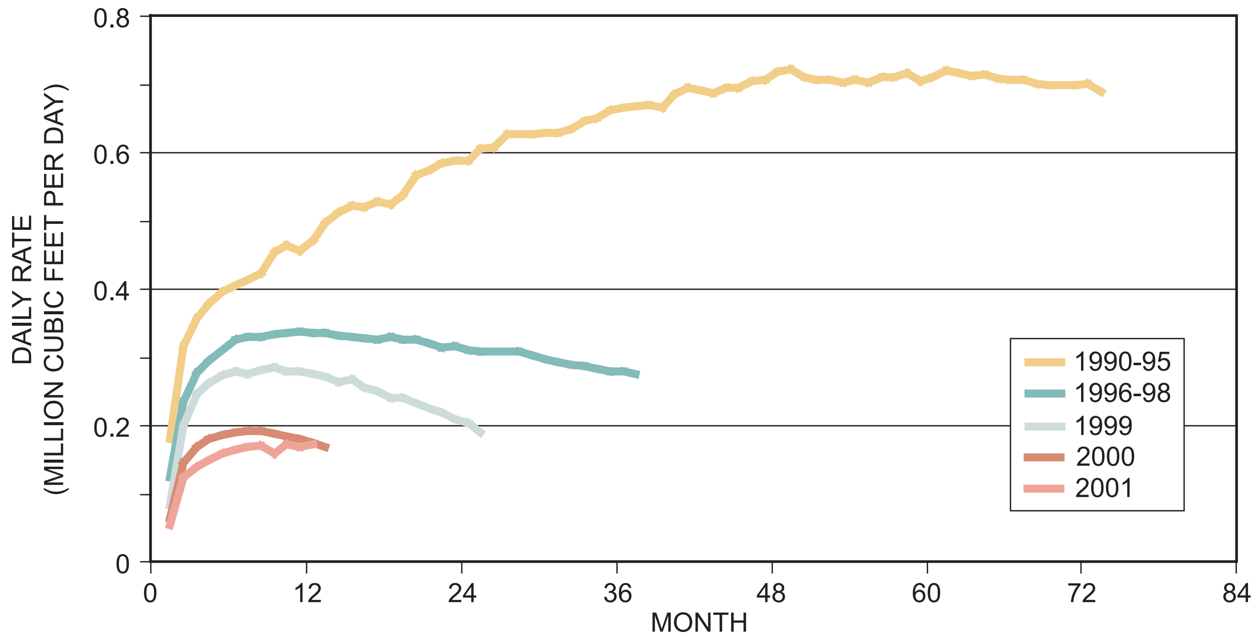
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-119. Rocky Mountain Gas Well Production, Cumulative (Raw, Wet Gas)



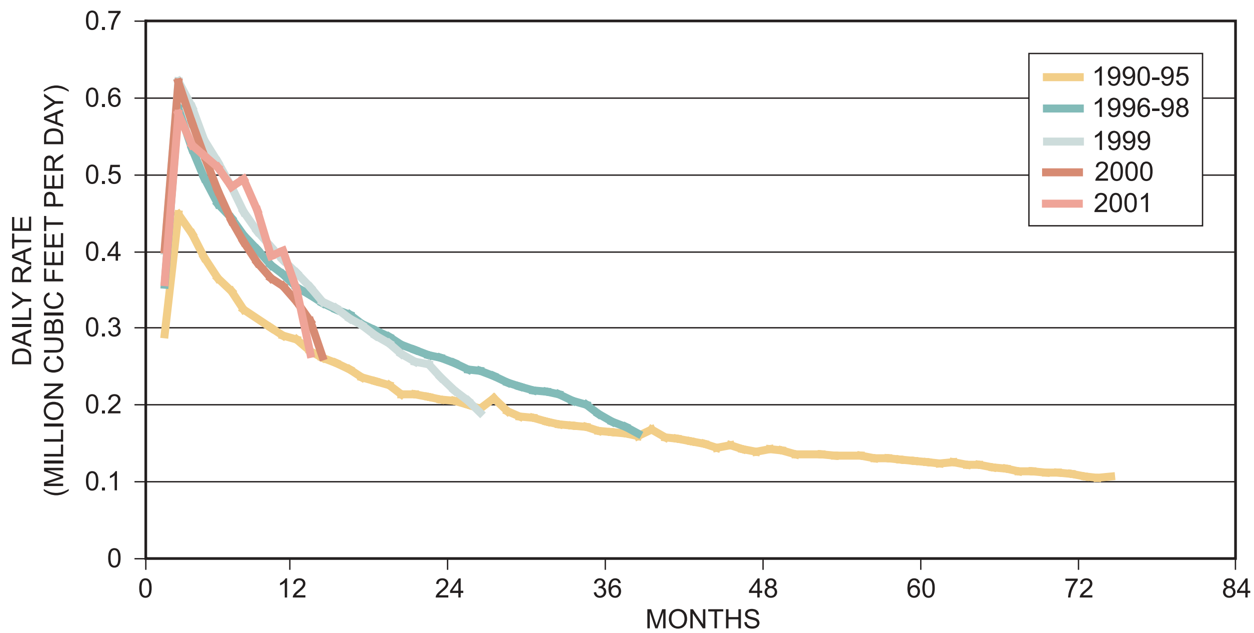
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-120. Rocky Mountain Gas Well Production, by Basin (Raw, Wet Gas)



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-121. Rockies Coal Bed Methane – Average Daily Gas Well Production vs. Time, by Year of First Production



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-122. Rockies Non-Coal Bed Methane – Average Daily Gas Well Production vs. Time, by Year of First Production

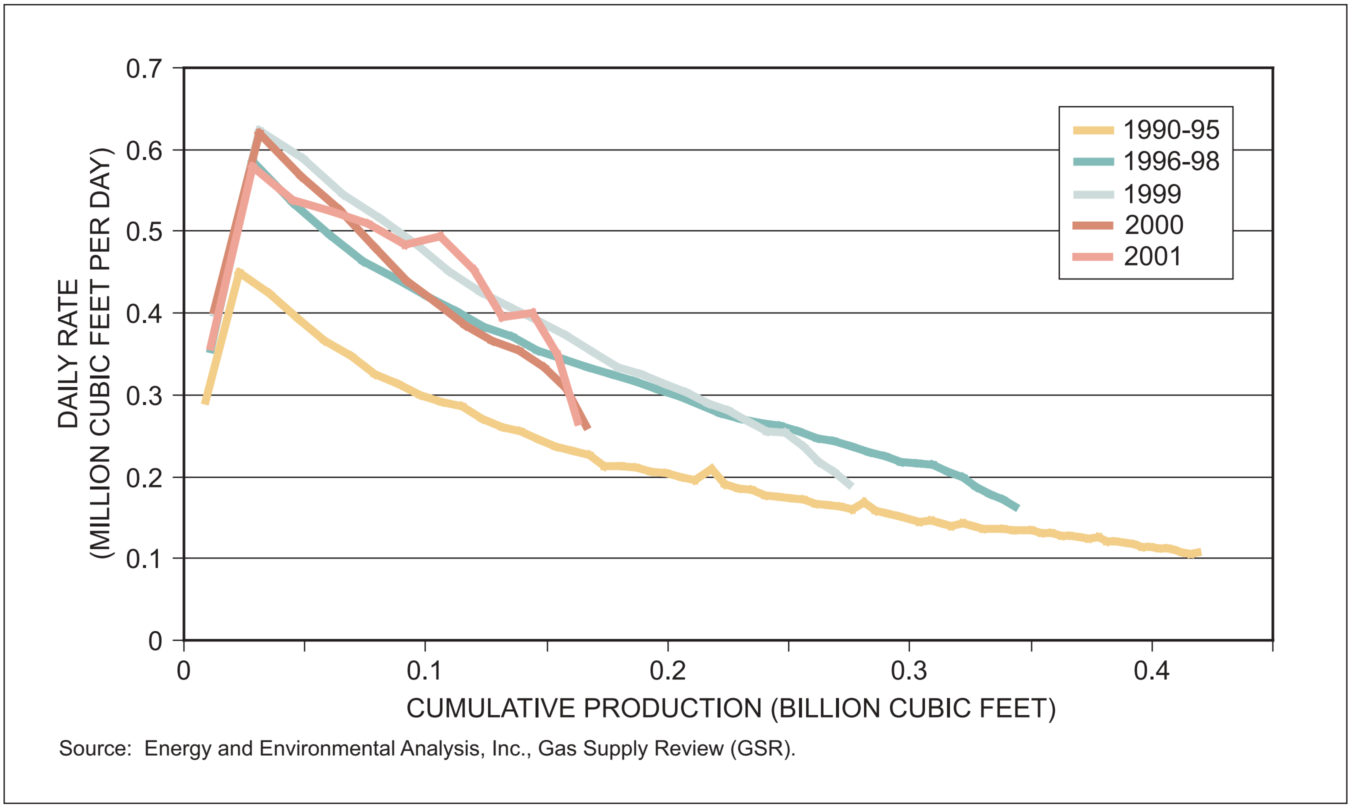


Figure S4-123. Rockies Non-Coal Bed Methane – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production

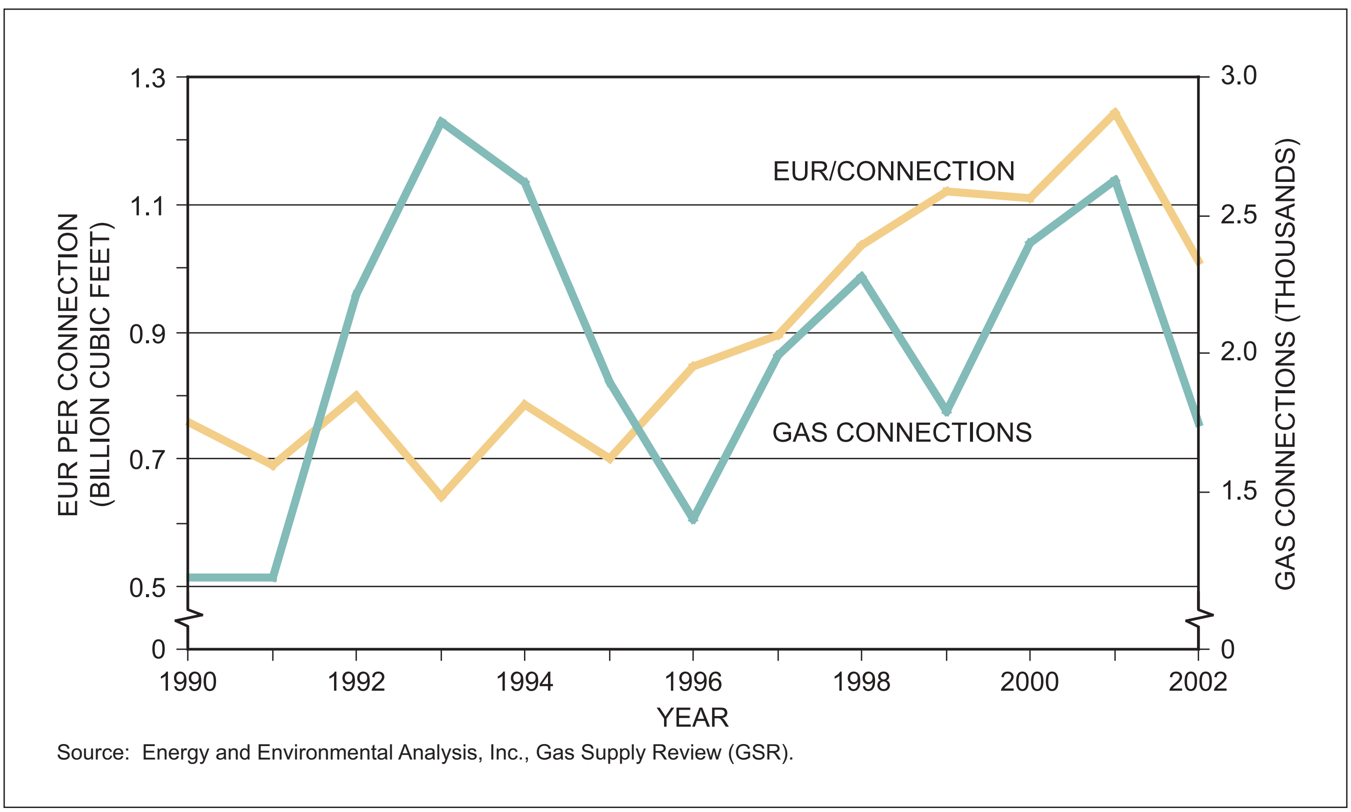


Figure S4-124. Rockies Non-Coal Bed Methane – Estimated Ultimate Recovery per Gas Connection

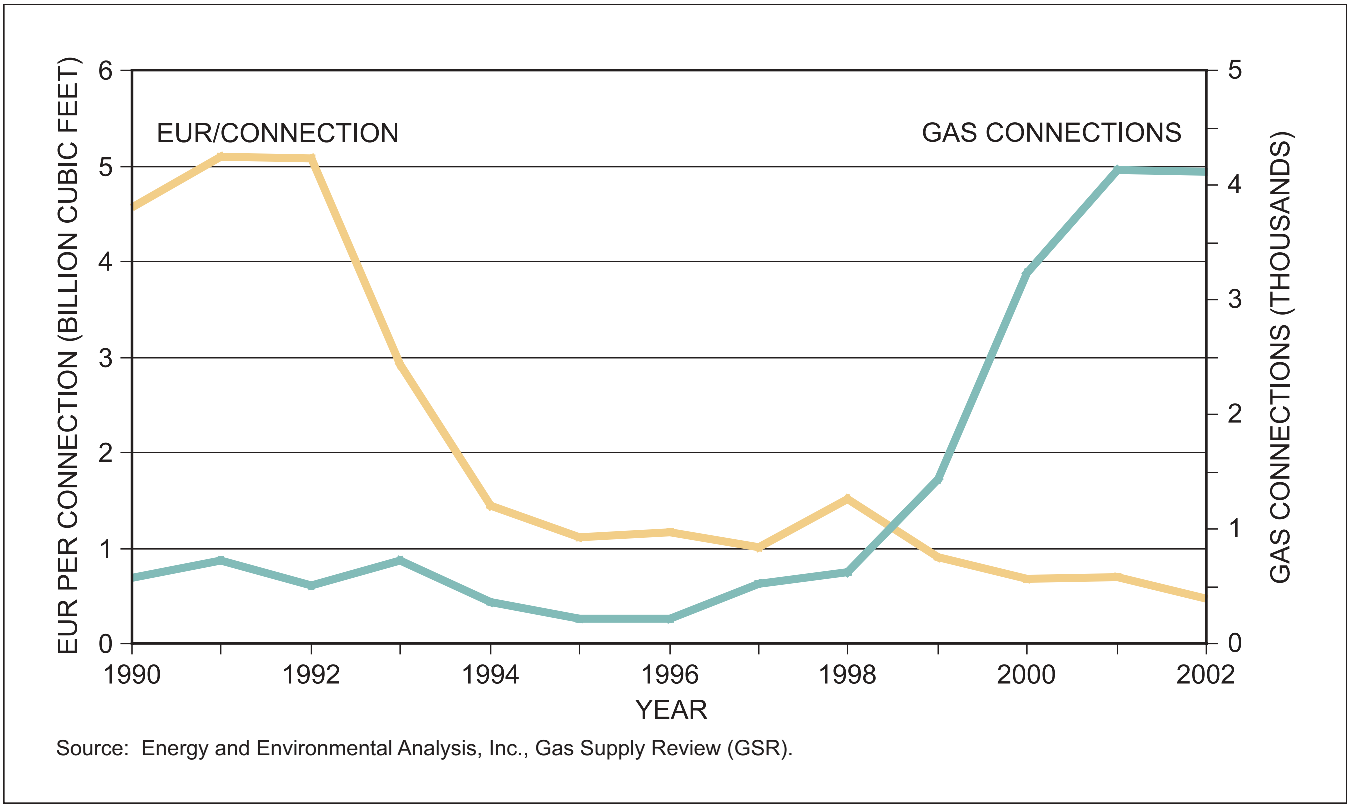


Figure S4-125. Rockies Coal Bed Methane – Estimated Ultimate Recovery per Gas Connection

rates began to increase. By 2001, base decline had grown to approximately 15%. New drilling needs to replace approximately 1.7 BCF/D for production to remain flat. (See Figures S4-126 and S4-127.)

4. Reserves

Gas reserves in the Rockies have continued to climb from 31 TCF in 1990 to 51 TCF in 2001. Rockies' reserves comprise 29% of total U.S. lower-48 reserves, up from 19% in 1990. The reserves-to-production ratio in the Rockies is about 12.8 years. Reserves from non-producing reservoirs has climbed from 7 TCF in 1997 to 14 TCF in 2001. (See Figure S4-128.)

I. Western Canada Sedimentary Basin

1. Historical Performance

Since 1990, 65% of the incremental supply of North American gas has come from increasing Canadian production, primarily from the Western Canada Sedimentary Basin. However, production growth in Western Canada has slowed dramatically, and 2002 was the first year that the Western Canada Sedimentary Basin experienced declining production. (See Figure S4-129.)

In the early 1990s, as gas export infrastructure was expanding, Western Canadian production grew rapidly, increasing 4.5 BCF/D from 1990 to 1995, from gas well completions averaging 3,000 per year. Production growth rates slowed through the rest of the 1990s, even as gas completions ramped up rapidly. Gas completions reached a peak of over 10,500 gas completions in 2001, or over three times the completions in the beginning of the decade. The 2001 and 2002 production rates were boosted by significant production volumes from the Ladyfern Field in British Columbia. This field is now on decline. (See Figure S4-130.)

On a regional basis, Northeastern Alberta production has been on steady decline since the middle 1990s. While over 50% of production comes from the western Alberta, after ramping up significantly in the late 1990s, production growth has leveled off and begun to decline. Southeastern Alberta production has recently been increasing, boosted by a large increase in shallow, development drilling. British Columbia production has recently increased sharply, as Ladyfern production has come on line.

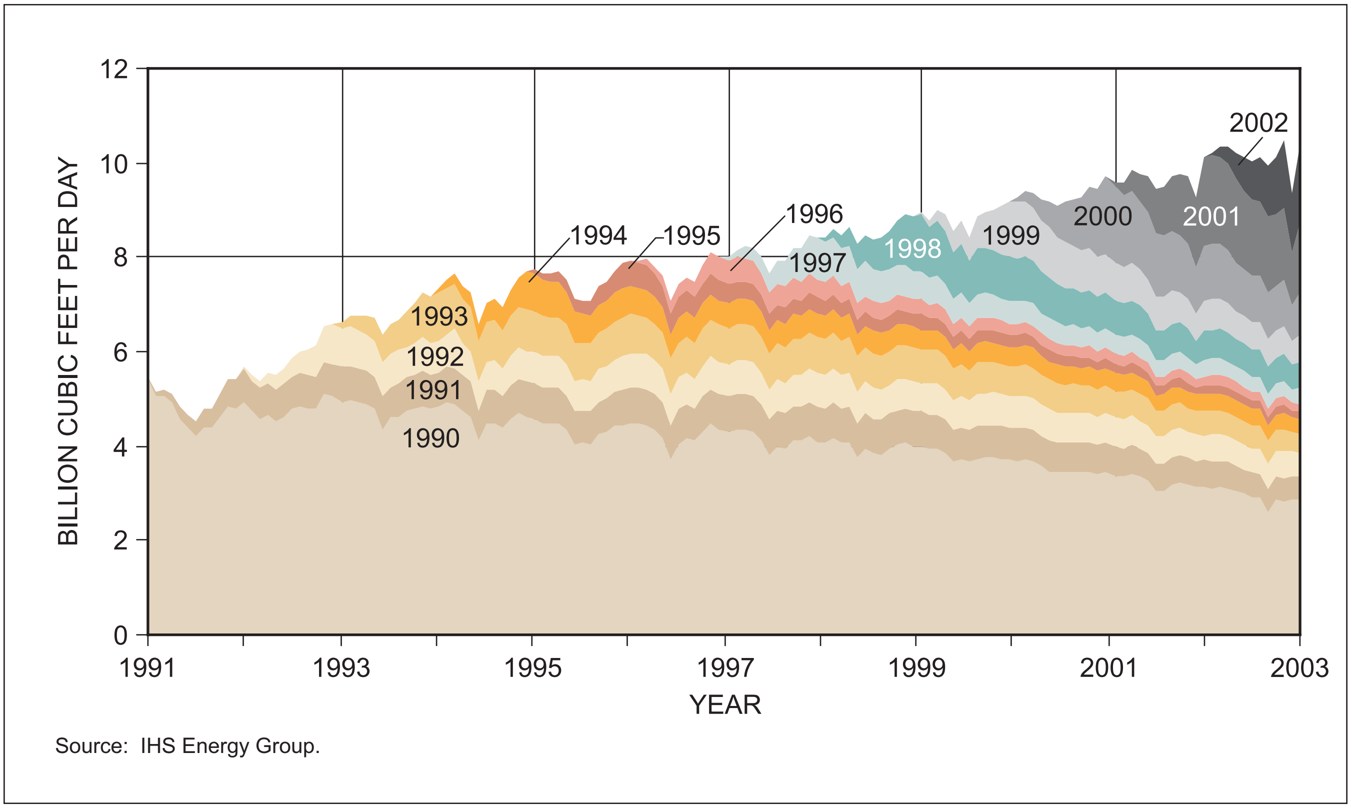


Figure S4-126. Rocky Mountains – Daily Wet Gas Production from Gas Wells, by Year of Production Start

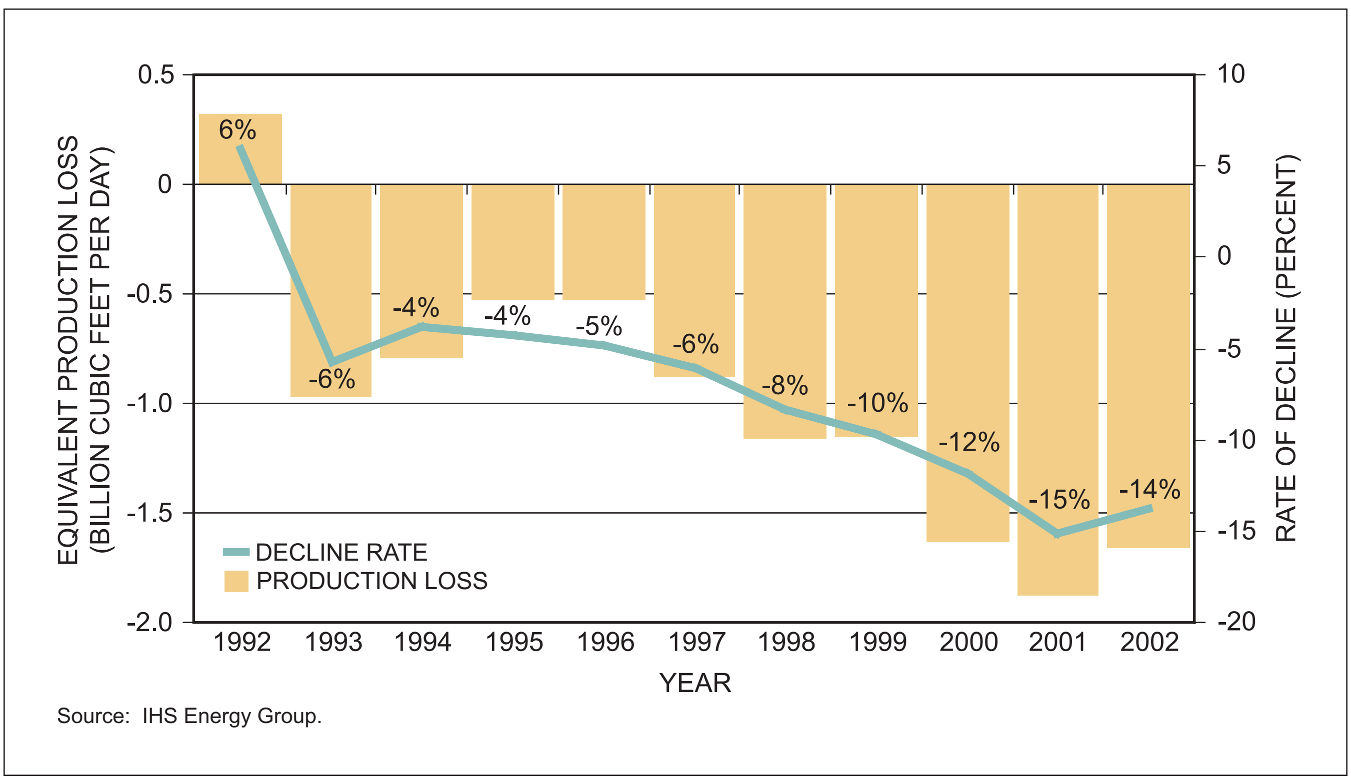


Figure S4-127. Rocky Mountains – Decline Rate of Base Gas Production if No New Wells had been Drilled, and Equivalent Production Loss

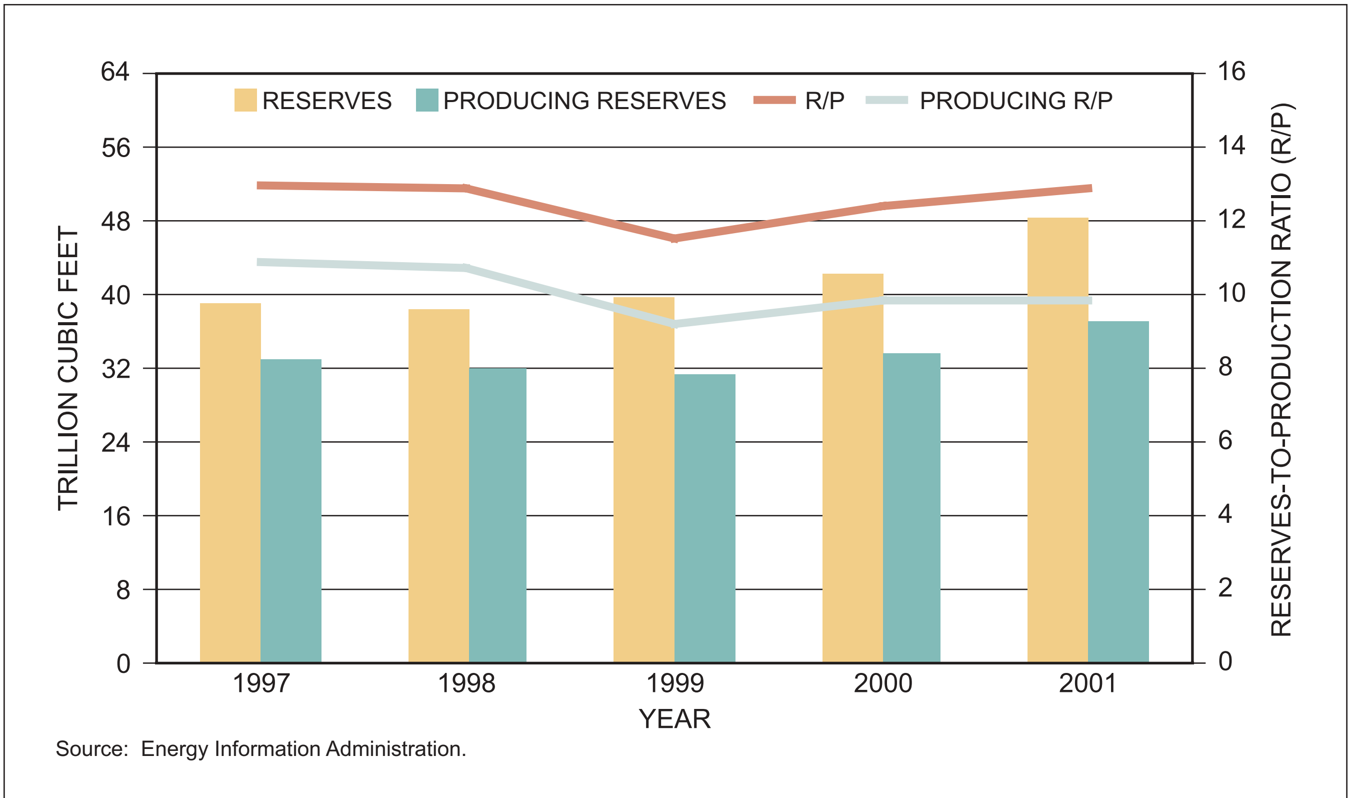


Figure S4-128. Rocky Mountains – Wet Gas Reserves

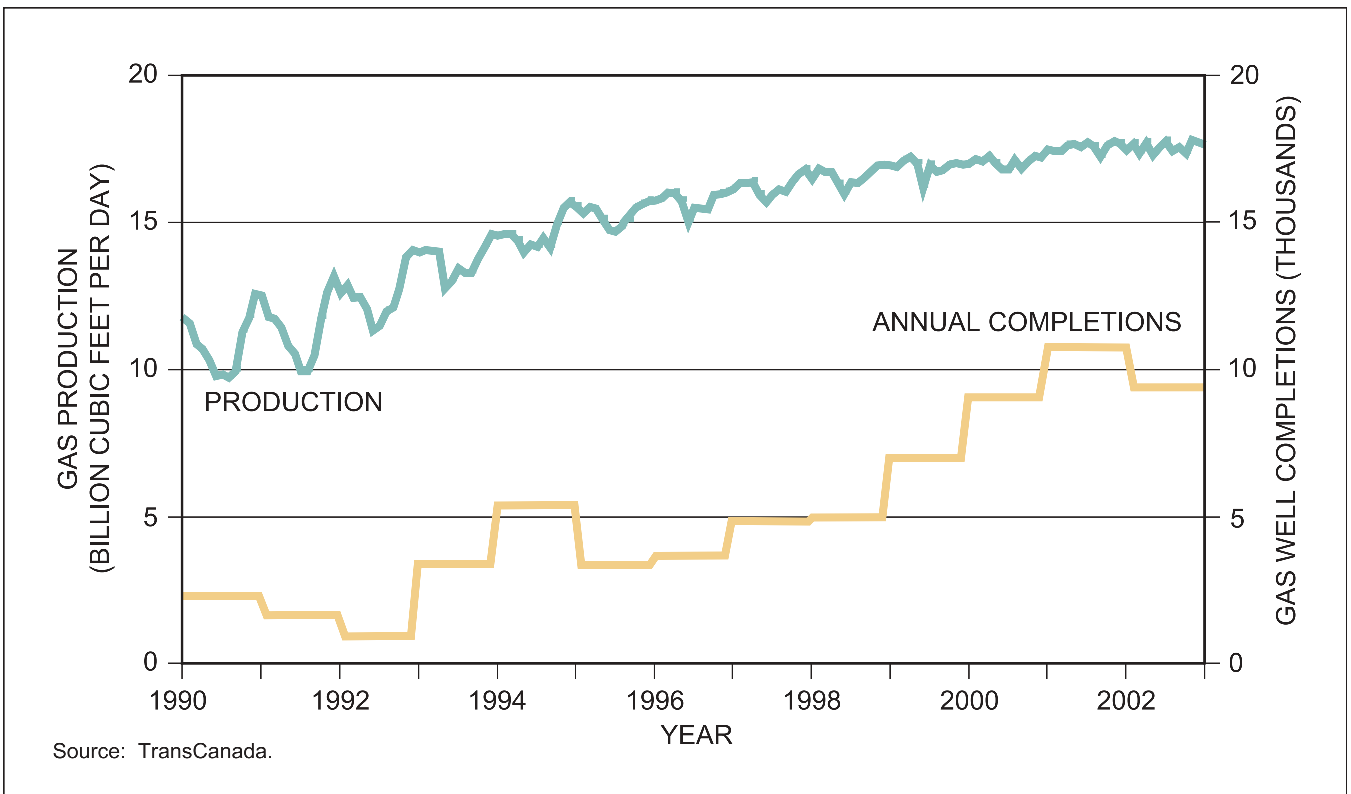


Figure S4-129. Western Canada Sedimentary Basin – Production and Gas Well Completions

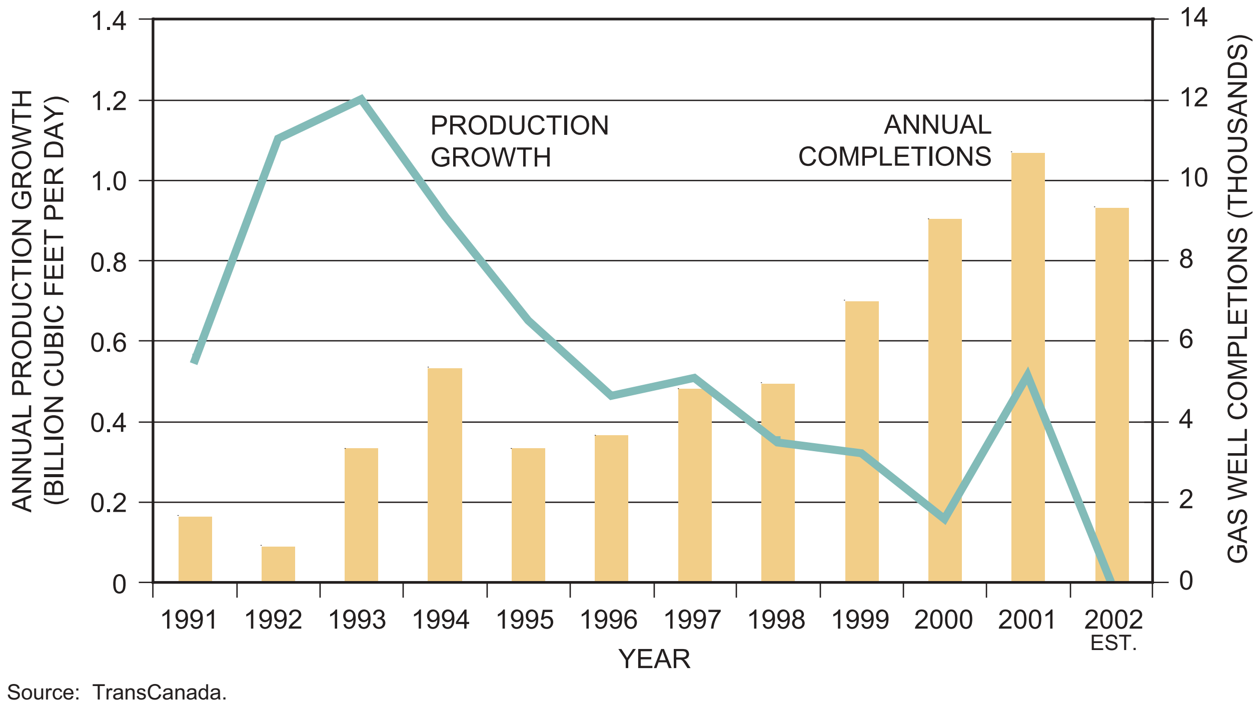


Figure S4-130. Western Canada Sedimentary Basin – Production Growth and Gas Well Completions

The basin is generally split into three geologic/producing regions, (1) the Cretaceous, (2) the Foothills, and (3) the Devonian. Supply in the Western Canada Sedimentary Basin is dominated by a very large number of small, Cretaceous pools, which are currently producing approximately 9 BCF/D. Through 2001, Cretaceous production had been growing under an aggressive development program targeting low-risk, shallow wells. As drilling rates dropped almost 20% in 2002, Cretaceous production fell for the first time in recent history. Foothills and Devonian pools are potentially larger, but are more technologically challenging and carry higher risk. While Foothills production has been steady at 2 BCF/D, Devonian production has grown recently from Ladyfern. (See Figure S4-131.)

The biggest current uncertainty for future production from the Western Canada Sedimentary Basin concerns coal bed methane and other nonconventional gas sources. 2002 marked the year in which the first coal bed methane reserves and production were booked. There are currently 10 to 15 coal bed methane pilot projects, and approximately 300 wells have been drilled, but as yet, production is minimal. It will take several years before the potential of coal bed methane in the Western Canada Sedimentary Basin can be evaluated.

2. Well Performance

Per well productivity in the Western Canada Sedimentary Basin has fallen significantly over the last decade, as a combination of smaller targets and well mix has negatively impacted EURs, IPs, and decline rates. (See Figures S4-132, S4-133, and S4-134.)

Average EURs in Western Canada have fallen from between 1.8 BCF/connection in 1990 to approximately 0.3 BCF/connection in 2001. While producers have progressively targeted low-risk shallow gas development drilling, with the exception of the Devonian which was positively impacted by Ladyfern drilling, both the Cretaceous and Foothills regions showed significant erosion in EURs over time. In conjunction with reserves per well having fallen dramatically, initial rates have also fallen from approximately 0.82 MMCF/D in the mid-1990s to approximately 0.47 in 2001. Accordingly, to achieve similar new well build-up required significantly more wells. First year decline rates have risen from approximately 20% in the early

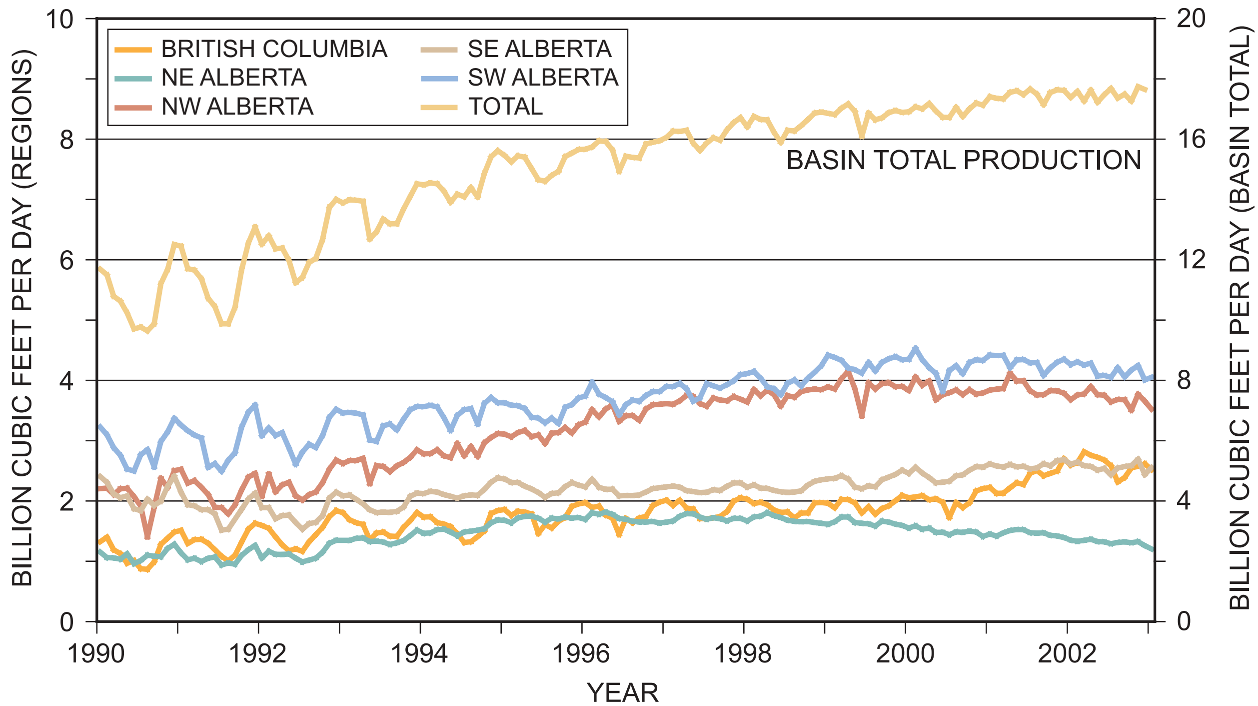
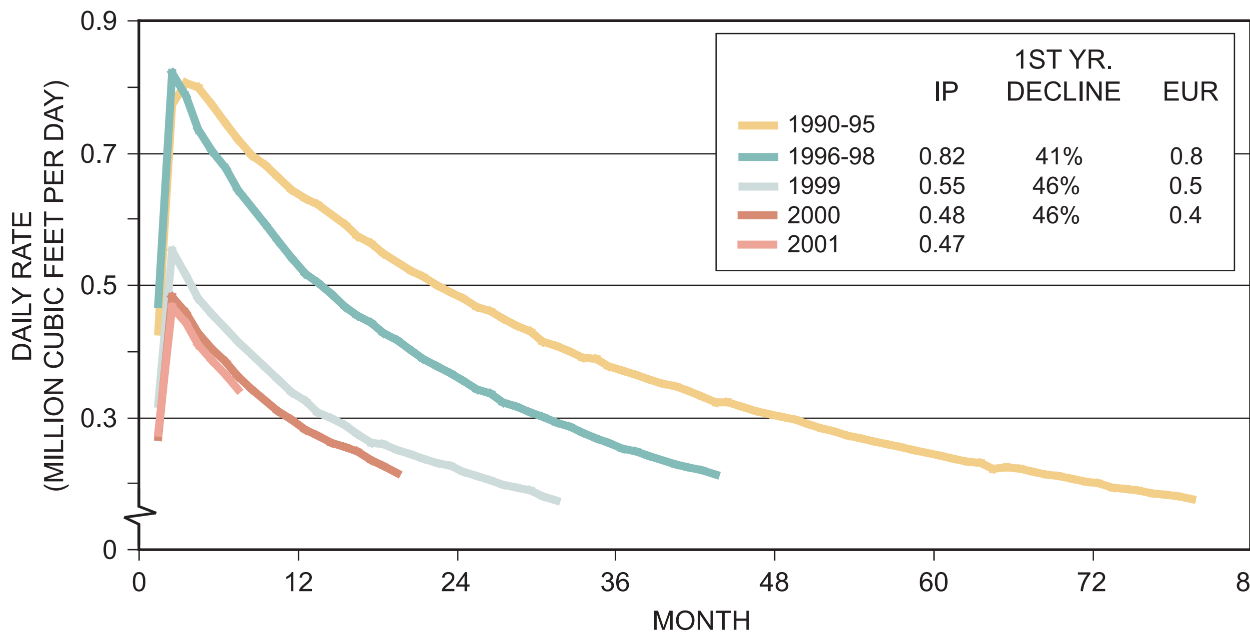
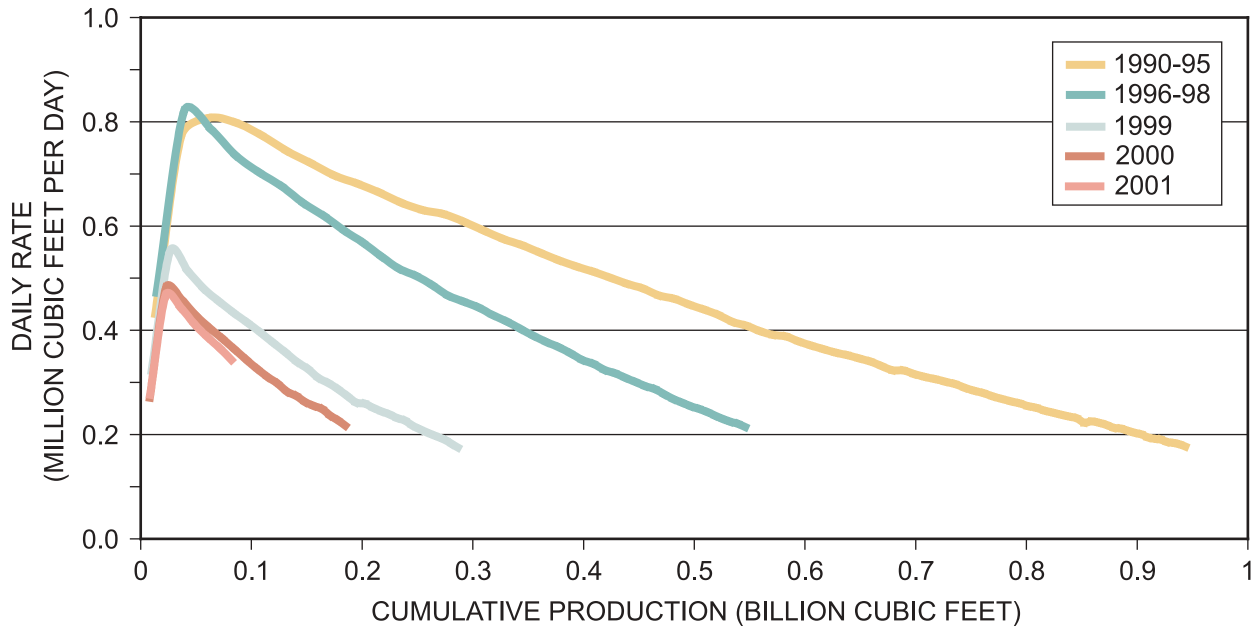


Figure S4-131. Western Canada Sedimentary Basin – Regional Production



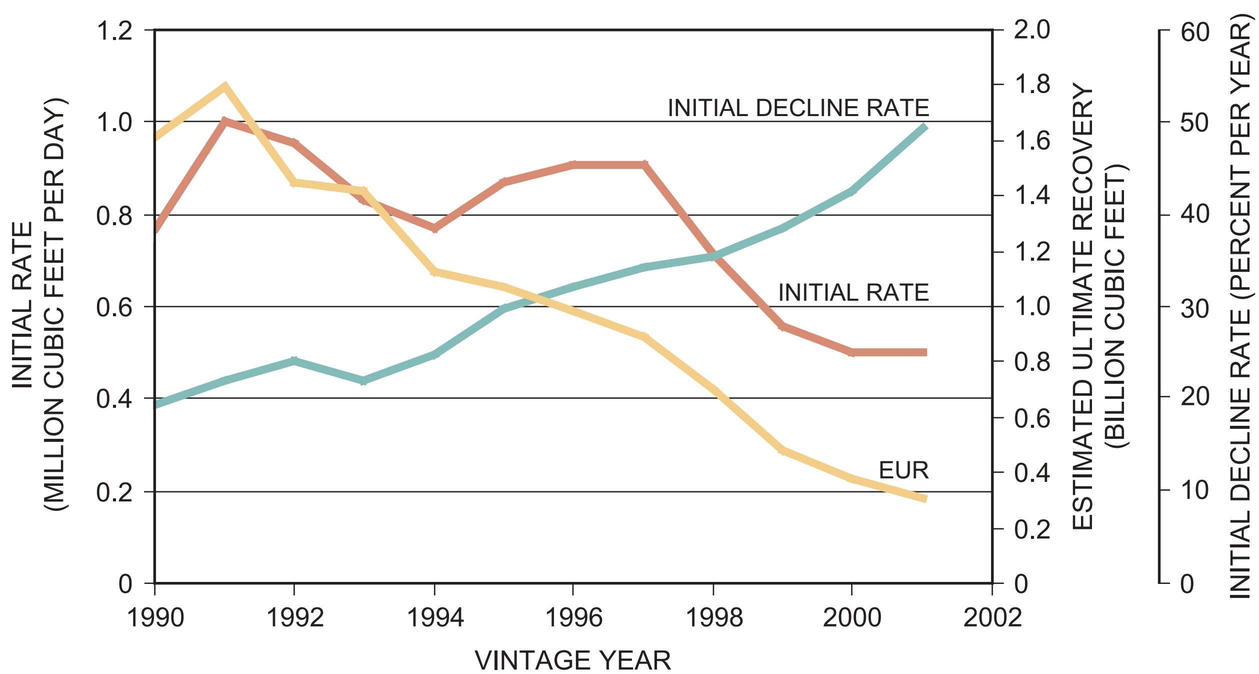
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-132. Western Canada Sedimentary Basin – Average Daily Gas Well Production vs. Time, by Year of First Production



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-133. Western Canada Sedimentary Basin –
Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-134. Western Canada Sedimentary Basin – Production Performance Trends

1990s to 45-50% in recent years. (See Figures S4-135, S4-136, and S4-137.)

3. Base Decline

As incremental well decline rates have increased over the past decade and smaller and smaller reserves have been exploited, the base decline rate for the overall Western Canada Sedimentary Basin has increased dramatically. Over the past five years, base decline rates have increased from approximately 2.8 BCF/D in 1997 to over 3.5 BCF/D in 2001, or 21%. Just to keep production flat, drilling has to produce over 3.5 BCF/D in 2001, which is up from under 2 BCF/D in the early 1990s. (See Figures S4-138 and S4-139.)

4. Reserves

Proved reserves in the Western Canada Sedimentary Basin have been falling since 1990, from 70 TCF in 1990 approximately 58 TCF in 2001. 2001 marked the first year since 1995 that proved reserves have risen. As reserves have fallen steadily and production has increased, the R/P ratio has fallen from a high of 18 to just over 9 over the past decade. If unconnected reserves aren't included, the R/P falls to 8. (See Figure S4-140.)

III. Analysis Process and Model Calibration

A. Summary

In order to help understand factors driving past production trends, to estimate future well performance parameters and to calibrate HSM model results, an analysis of historical production performance was undertaken for the U.S. lower-48 and Western Canada. In order to put more recent trends into a longer-term context, data was analyzed for the period from 1990 to the end of 2002. The analysis focused on the last four years of production performance, and as one key objective, specifically attempted to understand the reasons behind the lack of significant, sustained production response following the large ramp-up of industry activity in 2000 and 2001.

Production performance was analyzed using four basic parameters in an attempt to describe key trends and to understand the root causes driving those trends. The four parameters were:

1. Activity vs. Production;
2. Individual Gas Well Performance
   a. Estimated Ultimate Recovery or EUR
   b. Initial Production Rate or IP
   c. Initial Decline Rate;
3. Base Decline;
4. Reserves and R/P ratios.

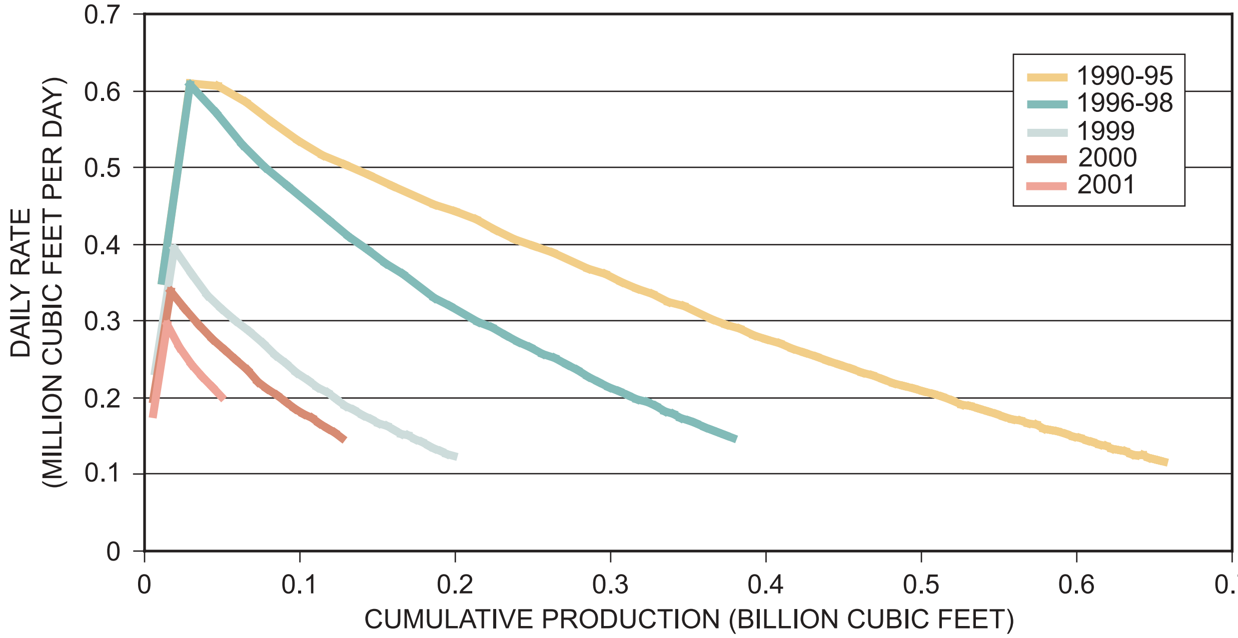
Energy and Environmental Analysis, Inc. (EEA) performed data compilation, manipulation, quality control, standardization, and analyses using a proprietary database system called the EEA Gas Supply Review, or GSR. EEA's GSR generally starts with IHS completion-level monthly production data. Raw, wet gas production is:

1. Adjusted for re-injected gas using IHS or state data;
2. Corrected for non-hydrocarbon gases (e.g., CO_2, H_2S, N_2) at the reservoir level using gas composition data;
3. Adjusted for NGL shrinkage using gas composition data or regional shrinkage factors; and
4. Adjusted for under-reporting of recent data using estimated production from existing completions and a forecast of future gas connections.

Performance parameters were summarized on a regional basis; however, most areas were analyzed on a more granular basis. The GSR is structured to allow production analyses at numerous levels:

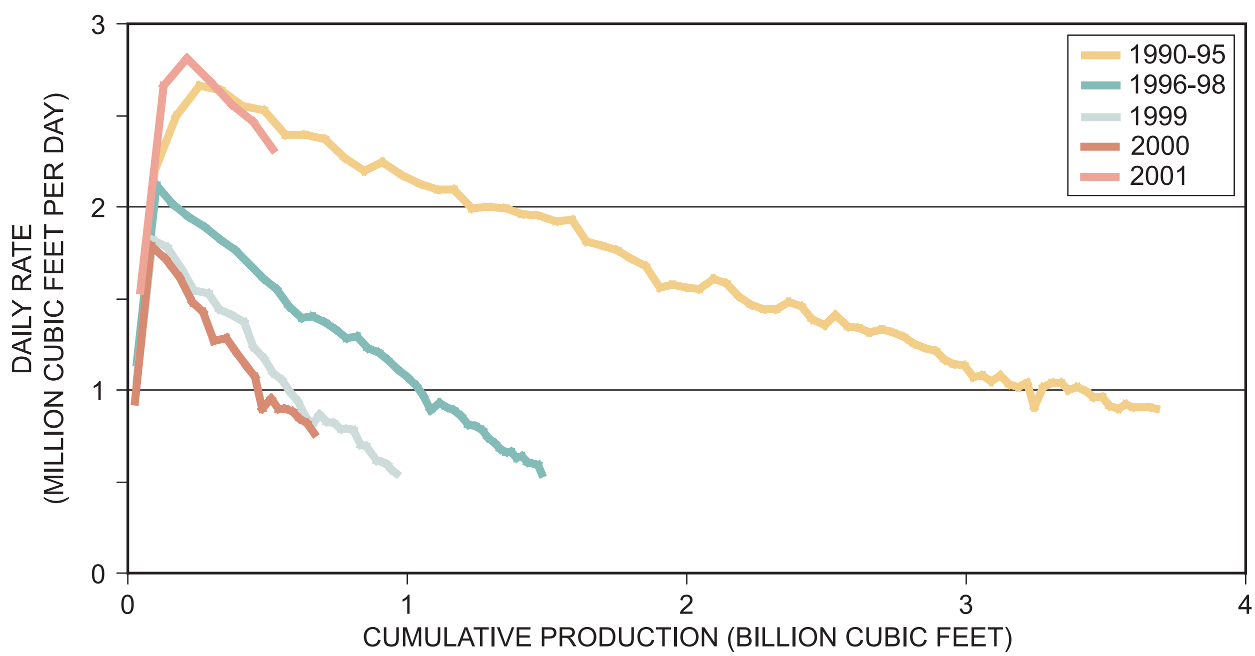
1. By Country – United States or Canada;
2. By Region – e.g., Permian Basin, South Texas Gulf Coast, Rocky Mountains, Alberta;
3. By Geologic Basin – e.g., Powder River Basin in Rocky Mountains, Foothills in Alberta;
4. By Geologic Formation – e.g., Frio, Vicksburg, and Wilcox in South Texas Gulf Coast.

Where necessary to understand production performance, analyses were also performed using other classification variables; for example, depth tranche (e.g., South Texas 10,000 feet to 15,000 feet) or resource type (e.g., coal bed methane vs. conventional performance).



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-135. Western Canada Sedimentary Basin, Cretaceous Pools – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-136. Western Canada Sedimentary Basin, Devonian Pools – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production

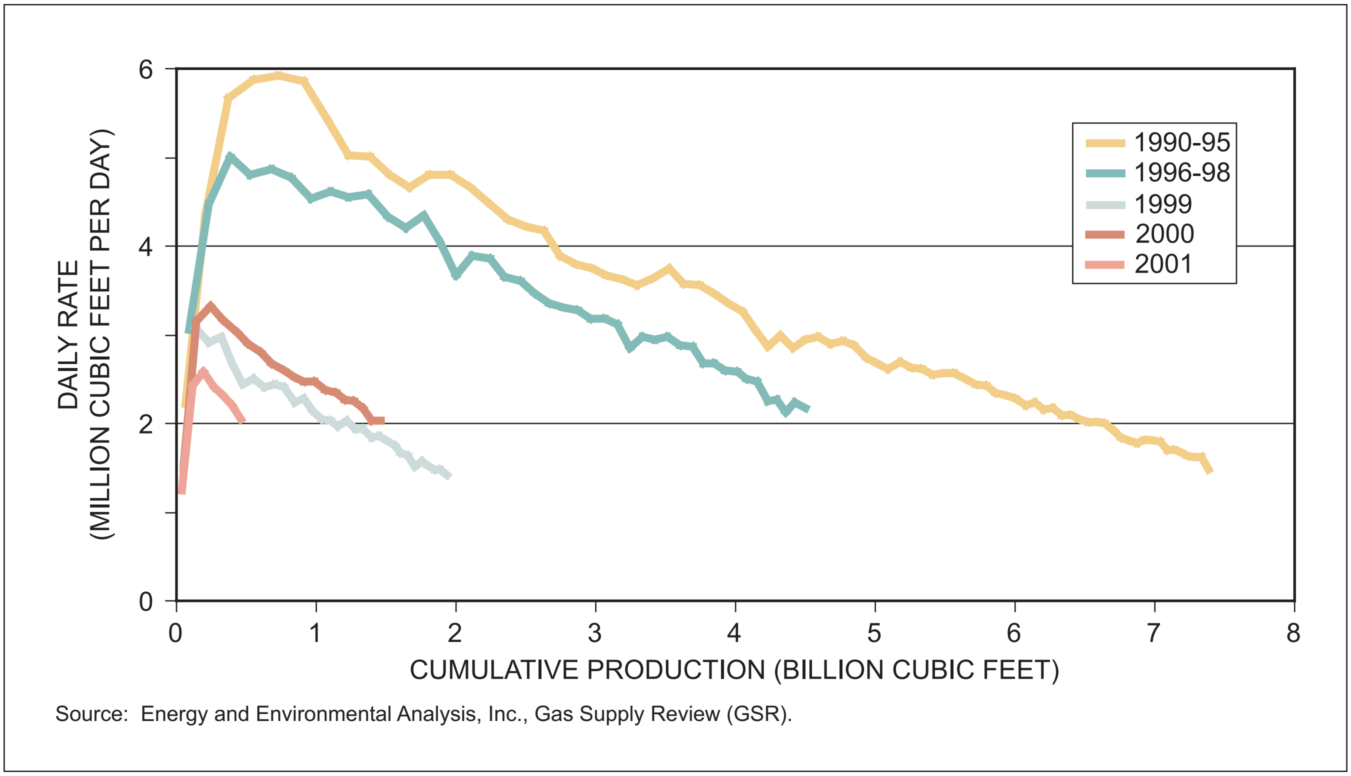


Figure S4-137. Western Canada Sedimentary Basin, Foothills Region –
Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production

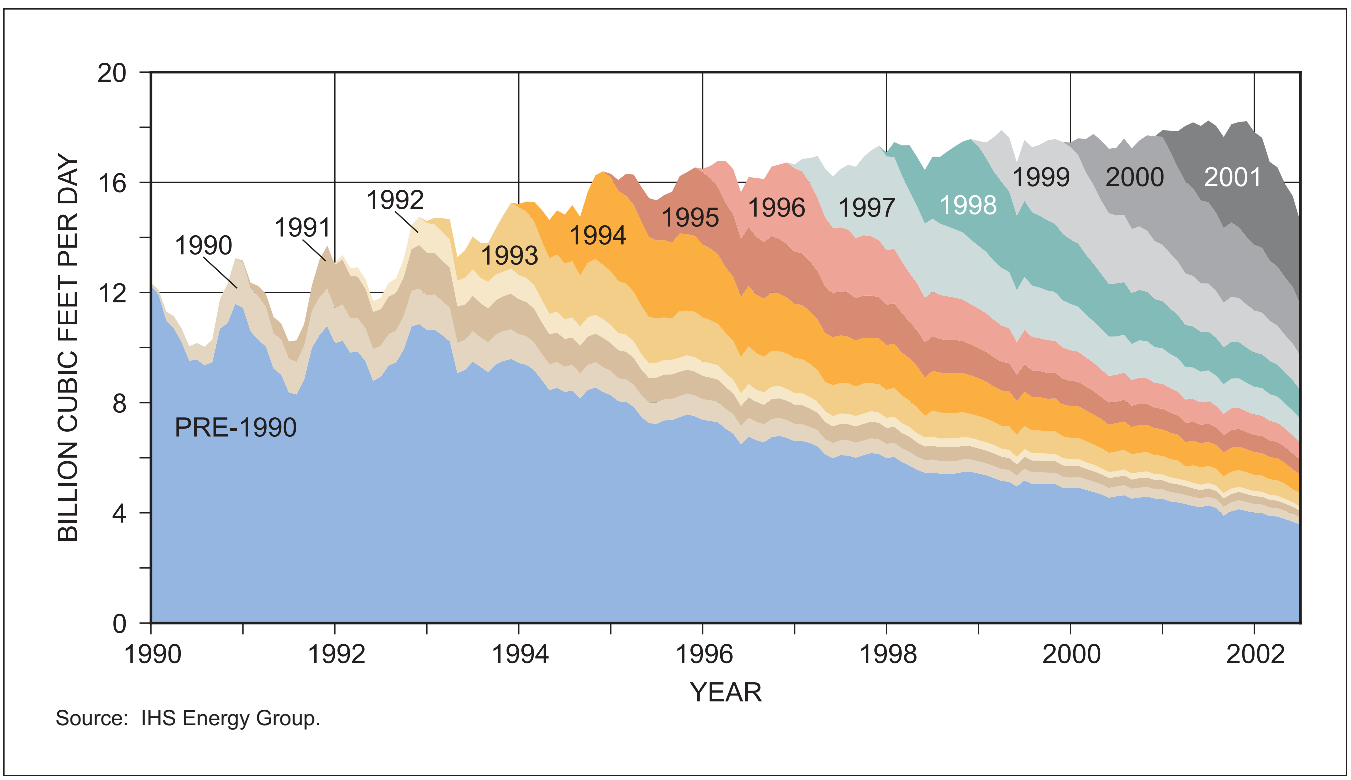


Figure S4-138. Western Canada Sedimentary Basin – Daily Wet Gas Production from Gas Wells,
by Year of Production Start

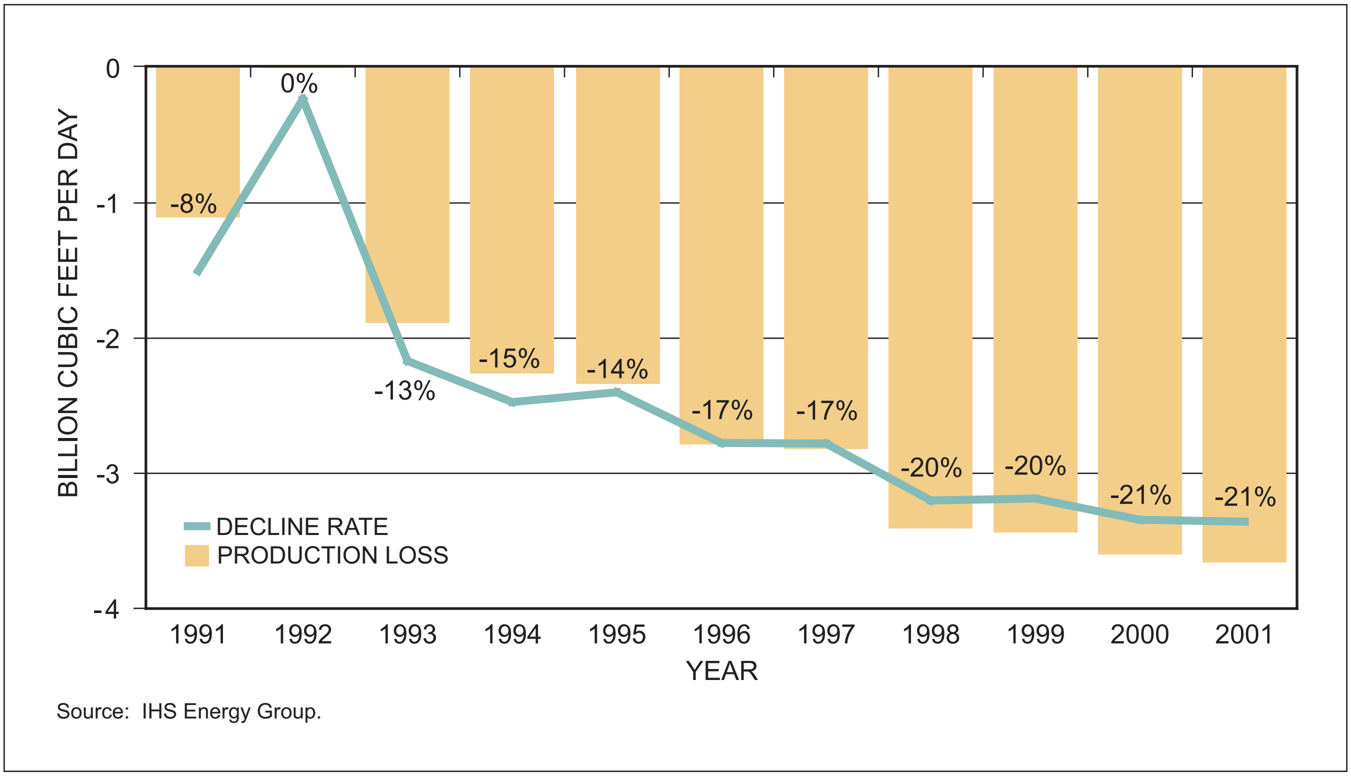


Figure S4-139. Western Canada Sedimentary Basin – Decline Rate of Base Gas Production if No New Wells had been Drilled, and Equivalent Production Loss (Non-Associated Gas)

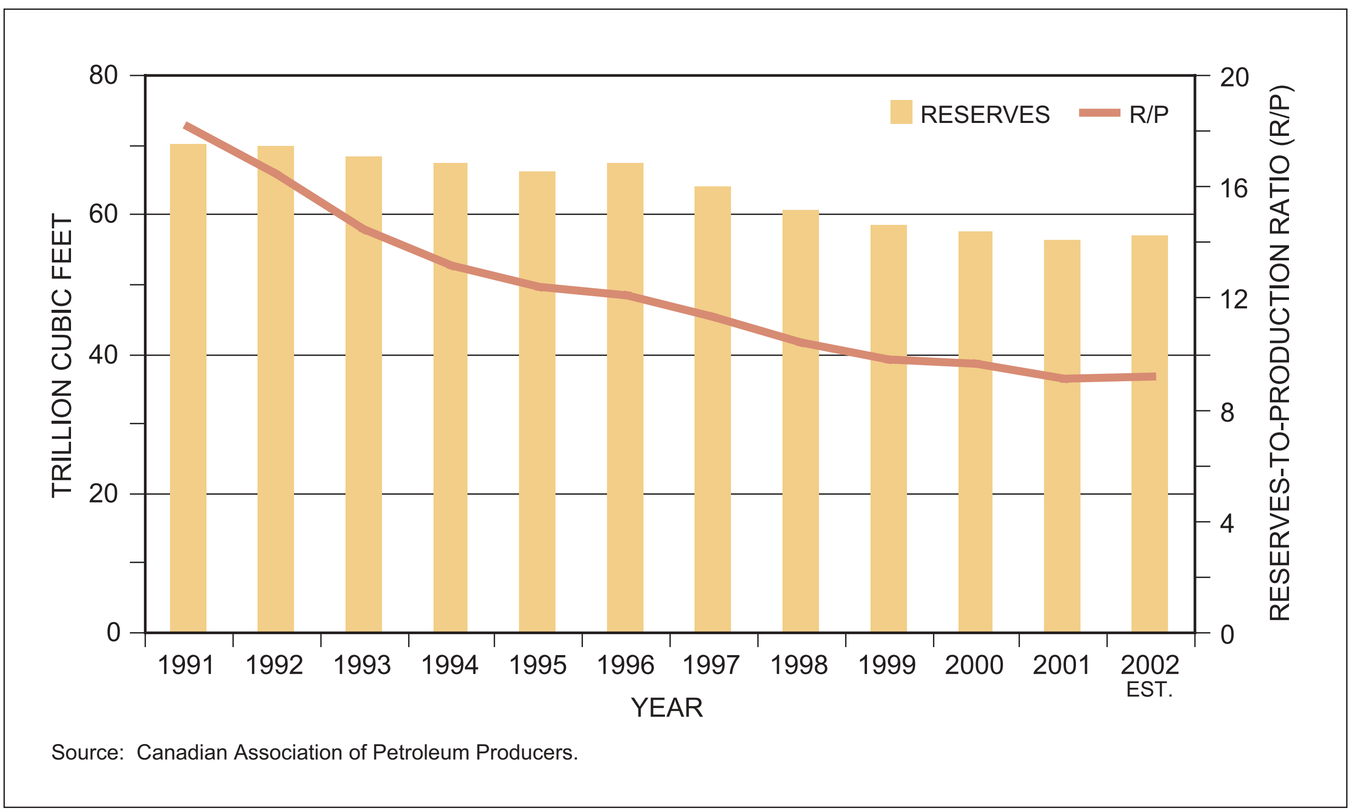


Figure S4-140. Western Canada Sedimentary Basin Proved Reserves

The Baker Hughes Rotary Rig Count and the API Quarterly Well Completion Report were utilized for certain analyses of activity levels. Proved Reserve estimates were taken from the EIA "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Annual Report," and for Canada from the Canadian Association of Petroleum Producers (CAPP).

The production performance parameters generated in the analysis were utilized either as direct inputs to the HSM, or to check HSM outputs.

B. Production vs. Activity

The first level of production analysis looked on a historical basis at gas production versus activity levels.

1. Gas Production

Gas production data, on a raw, wet basis emanated primarily from the IHS Production Database for U.S. production data and the IHS/Accumap Production database for Canada. Most of the analyses were performed on gas well production utilizing IHS data released in October 2002; however, regional production data were supplemented using more recent data released by IHS in May 2003. In certain areas the IHS production data was supplemented by production from state reporting agencies (e.g., Wyoming) and provinces (e.g., Nova Scotia). Appalachian production data was derived from the EIA "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Annual Report" and state agencies.

Production response was analyzed as appropriate on a number of different levels: (1) Country (2) Region, (3) Basin, (4) Formation. Figures S4-141, S4-142, S4-143, and S4-144 are charts of gas production vs. gas connections as granularity increases, from U.S. Lower-48, to Rocky Mountains (Region), to Green River Basin (Basin), and finally to Lance Formation (Formation). Well performance was also analyzed at this level of granularity.

2. Activity

Activity levels were generally analyzed using gas "connection" data. A gas connection is the occurrence of a new gas production entity in the IHS Production database. The date of first production in the IHS Production database is taken as the connection date. Connections can be the original drillwell, a sidetrack, or a re-completion. Unlike many other activity-based measures (i.e., the API Quarterly Completion Report,

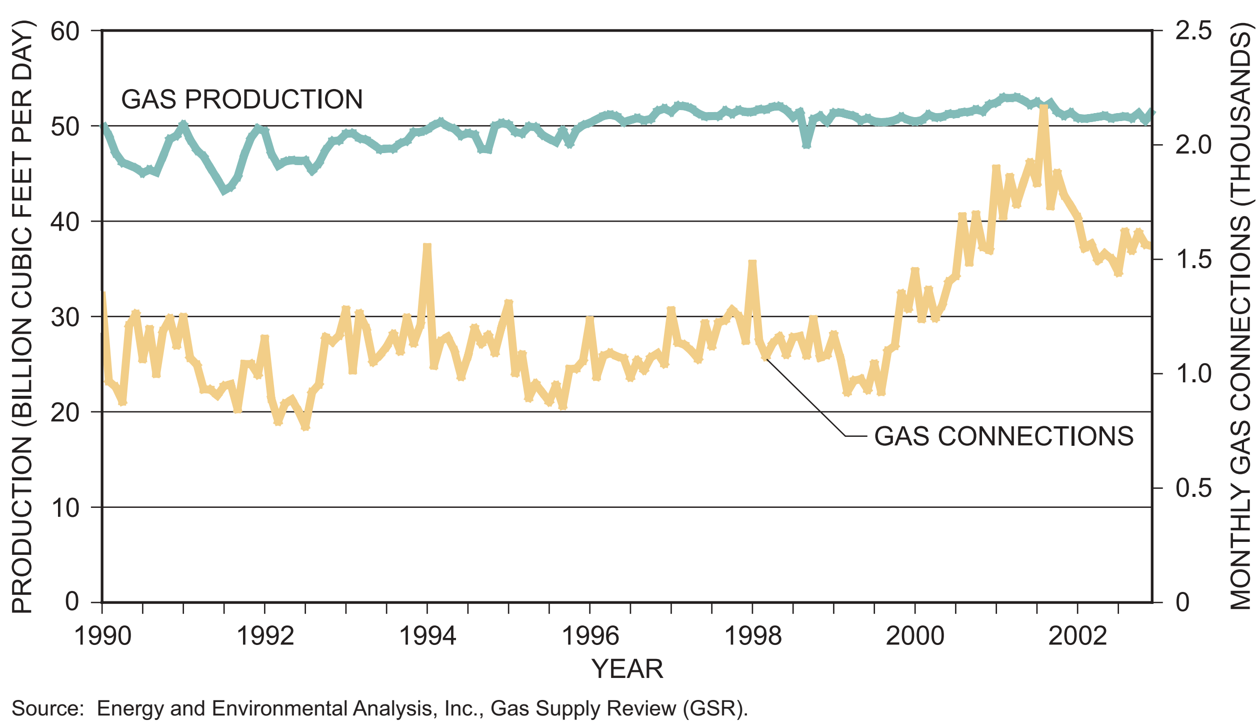


Figure S4-141. U.S. Lower-48 – Dry Gas Production and Gas Connections

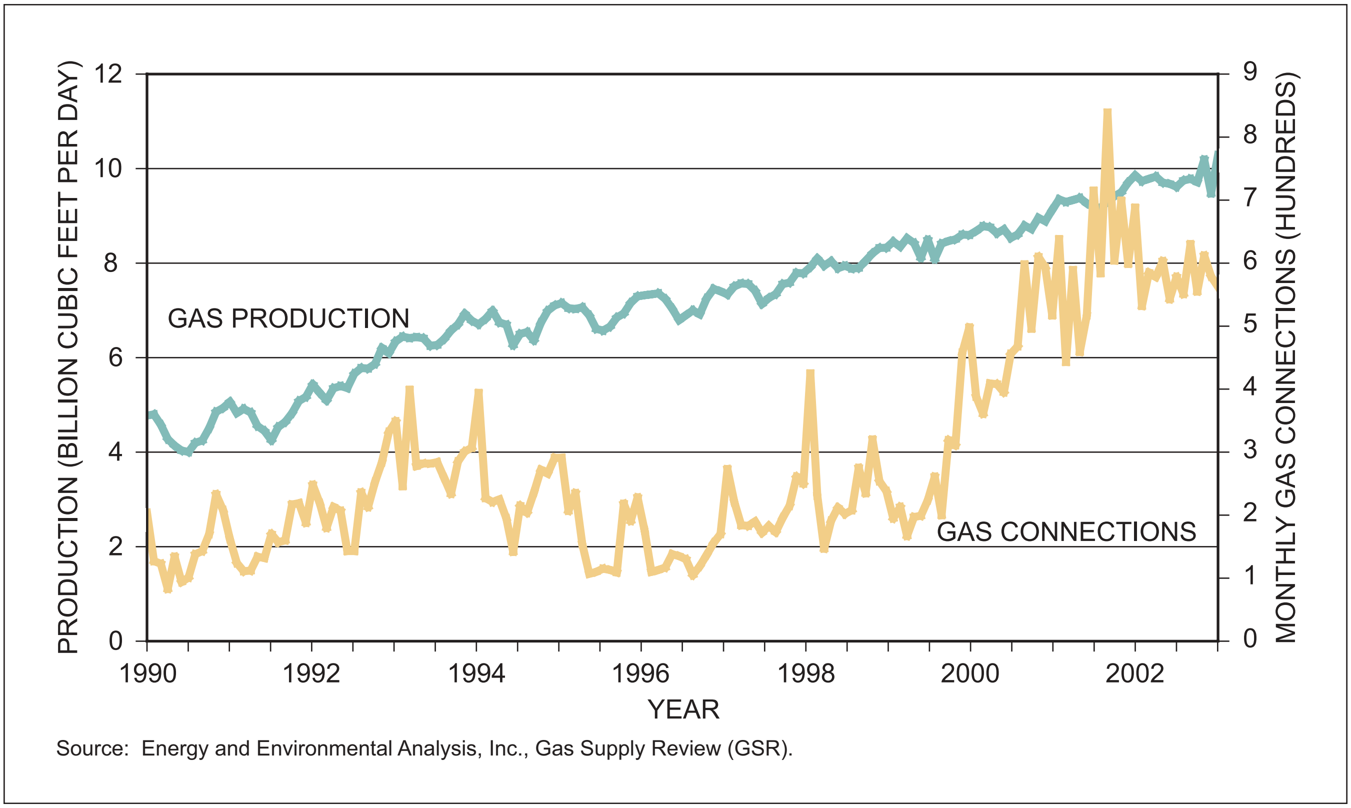


Figure S4-142. Rocky Mountain Region – Dry Gas Production and Gas Connections

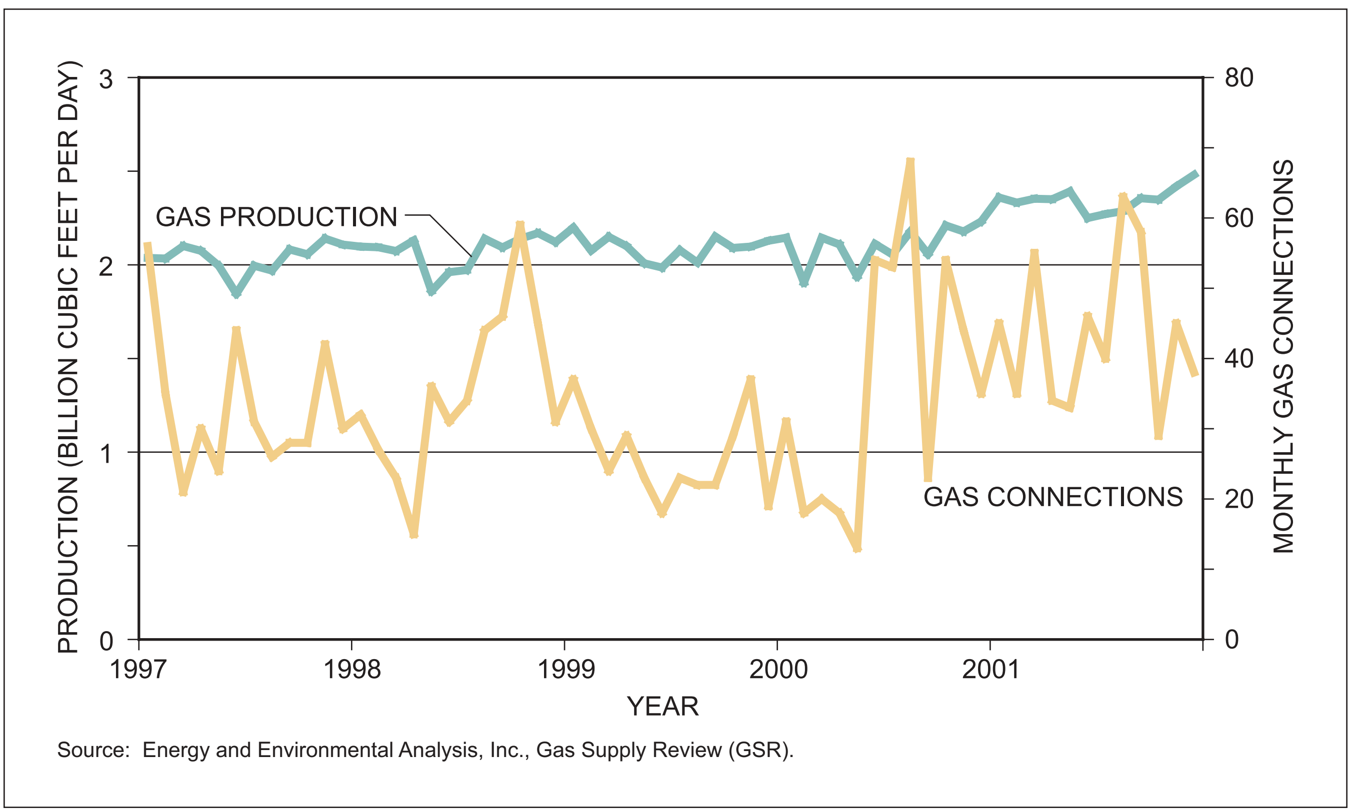


Figure S4-143. Green River Basin – Wet Gas Production and Gas Connections

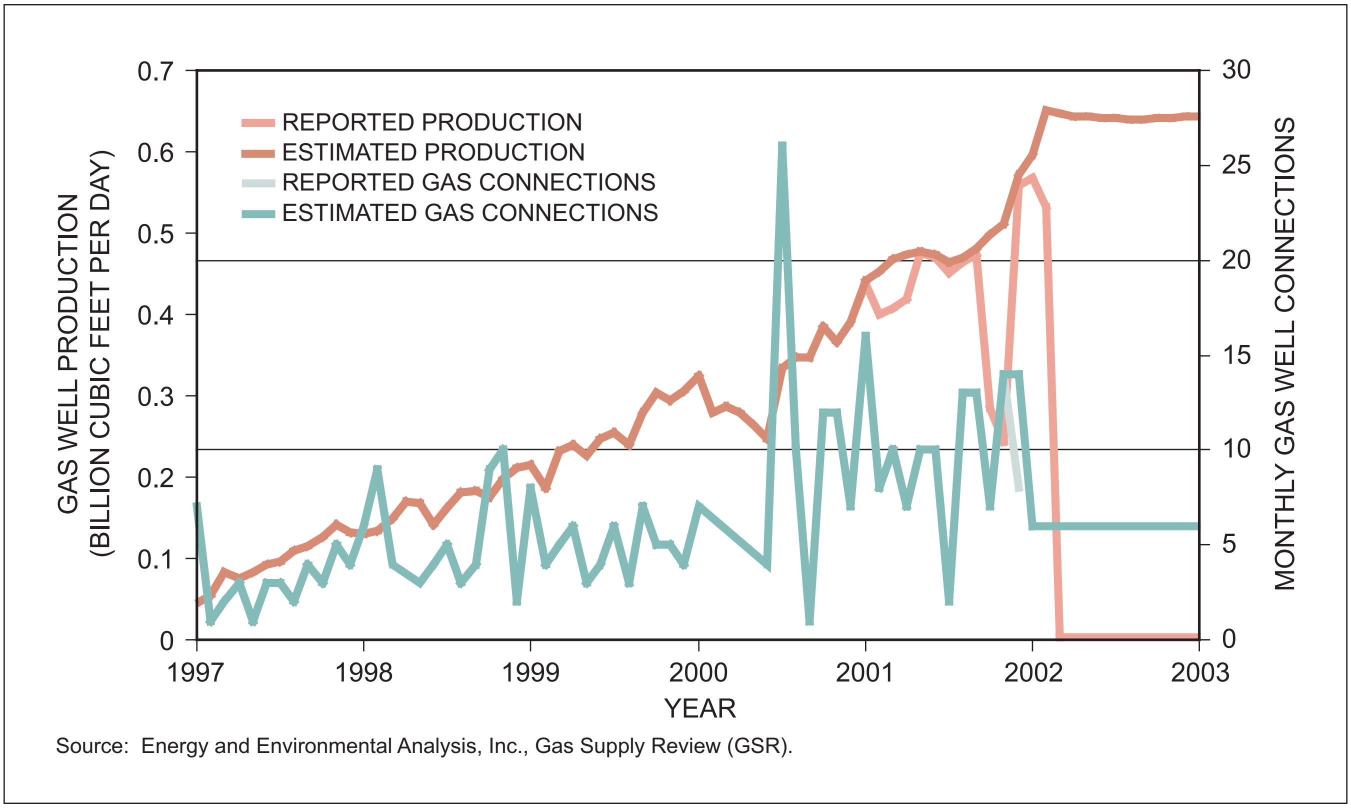


Figure S4-144. Lance Formation – Wet Gas Production and Gas Connections

the Baker Hughes Rig Count, etc.), connections measure all new production activities as opposed to drilling activities. As the IHS Production database does not completely cover per well reporting throughout the Appalachian Basin and Midwest, this study utilized API data to estimate activity levels in those regions.

In addition, certain analyses and plots used the Rig Count from Baker Hughes or gas completion data from the API Quarterly Well Completion Report to portray industry activity levels. As opposed to the GSR, which measures all new producing activities, these activity measures generally quantify only the original drilling of a wellbore. As detailed on their website, the Baker Hughes rig count does not include certain drill rigs, for example small truck-mounted rigs, a significant percentage of the drilling activity in shallow Powder River coal bed methane and some Appalachian areas.

Figure S4-145 illustrates the general similarities between the three activity data sources:

1. Baker-Hughes Rig Count – annual average annual gas rig count;
2. GSR Gas Connections – original gas drillwells/sidetracks (excludes recompletions) + Appalachian/Midwest data from API; and
3. API estimated gas well completions.

As evidenced by Figure S4-145, *after excluding recompletions*, all three activity measures follow generally similar trends, particularly in the early to mid-1990s. More recently, while the three data series continue to follow similar growth patterns, the API Well Completion data has systematically higher activity levels than the GSR Drillwells/Sidetracks as adjusted for the Appalachia/Midwest. Possible reasons for the more recent differences include:

1. API estimation procedures – API employs a statistical procedure to correct for the significant underreporting of recent well completions. API reports the estimated well data at the national level, which prevents evaluation of the underreporting on a state or regional basis. Underreporting is a much more significant problem for recent drilling.
2. Gas producing wells vs. completed wells – The GSR only counts wells that are producing gas, while API

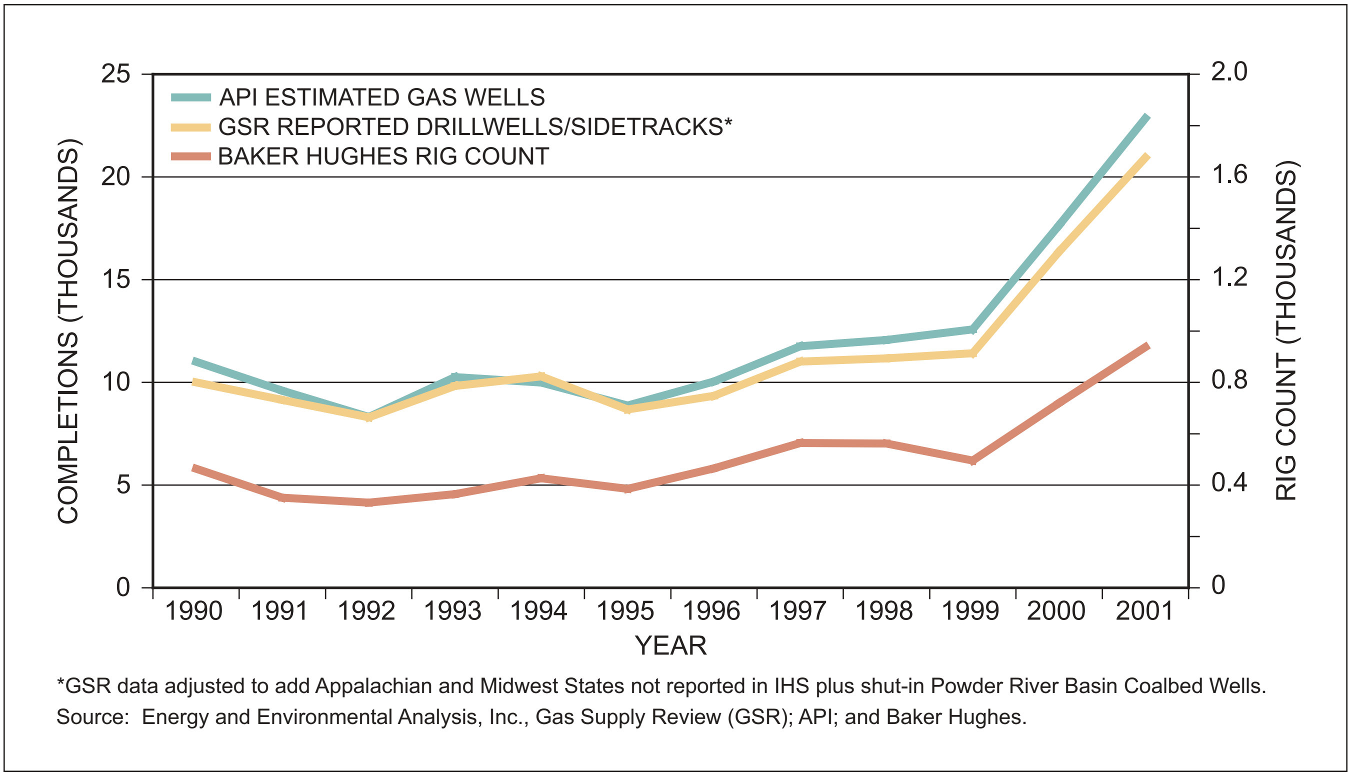


Figure S4-145. U.S. Gas Well Completions and Rigs – New Drillwells (Excludes Recompletions)

data includes all wells having installed production equipment. Completed but shut-in wells or dewatering wells are not counted in the GSR statistics. In places like the Powder River Basin, with a very large ramp-up of drilling activity in the late 1990s, the difference could be very large.

3. Uneconomic gas wells – Wells drilled as gas wells and reported in the IHS Well Data database (the original source for the API data) may be uneconomic and never appear in the IHS Production database (source for the GSR).

While Figure S4-145 excluded recompletions from the GSR connection count, per connection analysis of performance included recompletions. Recompletions are a very significant and fairly stable part of gas well connections as evidenced by the chart of lower-48 gas connections by type detailed in Figure S4-146.

3. Nonconventional Gas Production

EEA compiled nonconventional gas production statistics from several sources: the EEA GSR, the GTI Gas Resource Database (also produced by EEA), and literature to produce a complete historical overall picture of lower-48 nonconventional gas production (coal bed methane, shale gas, and tight gas). (See Figure S4-147.) The EEA GSR database includes all significant coal bed methane including the Appalachian Basin (data sources include IHS and state agencies) and most non-Appalachian shale gas production but does not distinguish low-permeability (tight) gas. (The GSR includes production from the Antrim Shale and the Barnett Shale. The GTI database and a GTI "GasTips" article were used as sources for the Devonian Shale, New Albany Shale, and Lewis Shale gas production that is not broken-out in the GSR.)

a. Tight Gas Production

Tight gas production data through 1999 were obtained from the GTI database; tight gas production for 2000, 2001, and 2002 were estimated. The GTI database identifies tight gas based on the FERC Section 29 tight gas formation designations and the Texas severance tax incentive program designations. Both the FERC and Texas programs define low permeability "tight" gas reservoirs as having a permeability of 0.1 millidarcy or less.

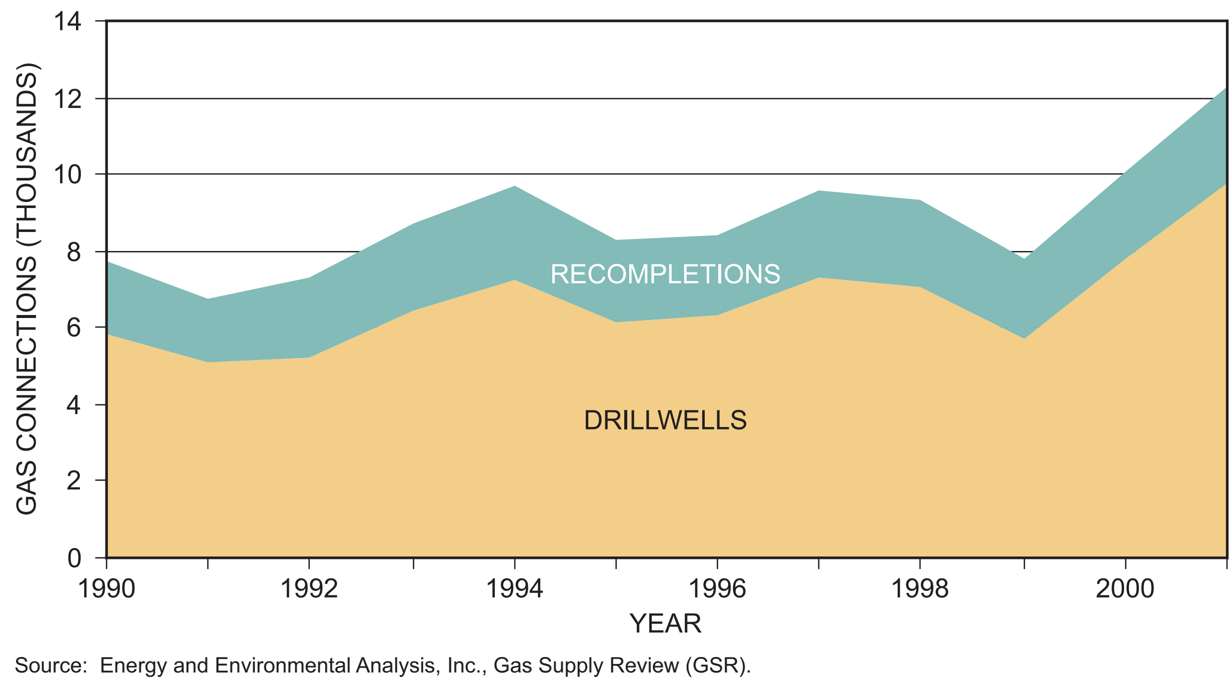


Figure S4-146. Lower-48 Non-Appalachian Onshore Conventional and Tight Gas Connections by Completion Type

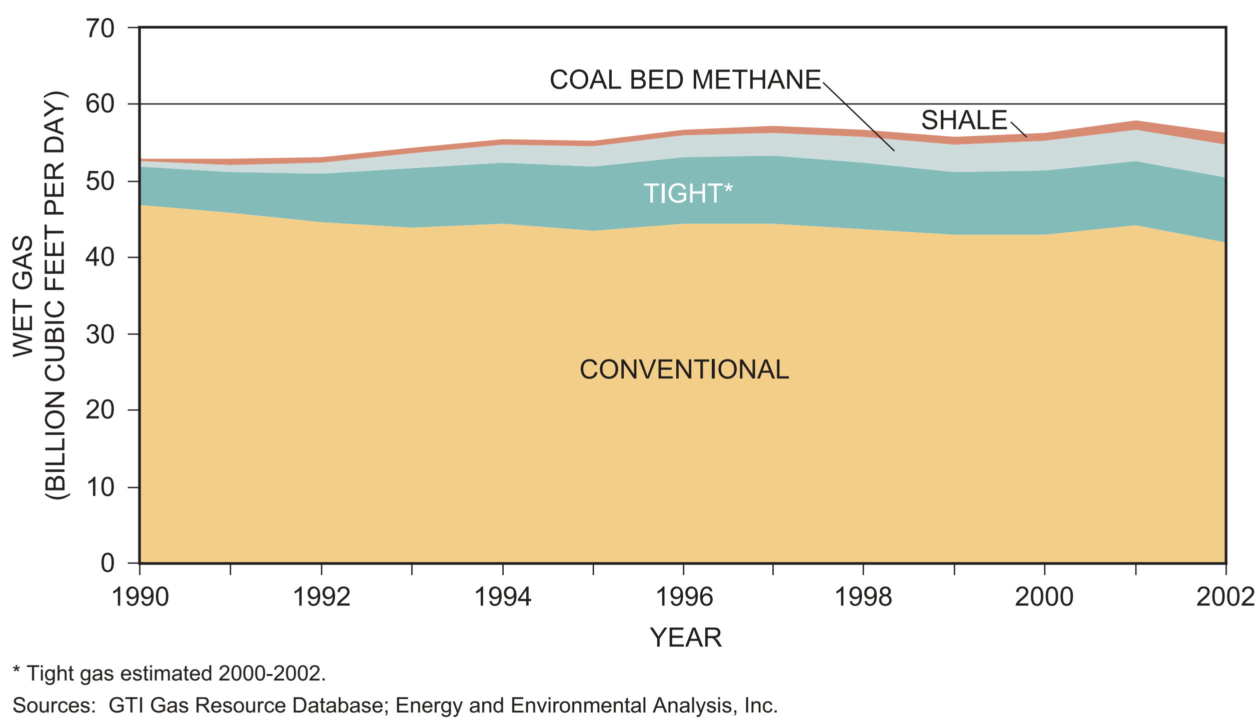


Figure S4-147. U.S. Lower-48 Wet Gas Production by Resource Type

In the GTI database, EEA identified tight gas using three approaches:

1. *Location-based identification (non-Texas, non-Appalachian areas).* Map location information was used to identify tight fields and reservoirs in recently designated areas. EEA created lookup tables using section-township-range-formation designation data. In this manner, all of the gas *completions* within the designated formation and area were identified.

2. *FERC Form-121 tight gas well determination data (non-Texas areas).* The FERC 121 Section 107 tight gas well determination data were used to identify specific wells that have qualified for tight gas incentive pricing. EEA merged the FERC 121 file with the Dwights gas completion database by API well number to identify the population of fields and formations that are "officially" tight. The merge results were screened to eliminate commingled (multi-zone) wells. All completions within the screened field/formations were initially flagged as tight, this step was followed by another edit step to eliminate errors such as large conventional reservoirs flagged tight based on a single FERC well.

   The FERC data were also used to estimate Appalachian tight gas production in states such as West Virginia where we were able to obtain well level production data. A county-level approach using state agency and FERC designation data was utilized for other Appalachian states such as Virginia.

3. *Texas RRC "high cost gas tape" – exclusive approach used in Texas.* This database tracks all of gas well filings under the federal and state incentive programs. The RRC tape is an excellent source of tight gas identification because it identifies individual gas completions and contains very recent identifications.

C. Individual Gas Well Performance

Average gas connection performance was analyzed using "vintage plots" or "Time-Zero plots." The concept of a vintage plot is to normalize production data from all connections brought onstream during a given year to an equivalent production time scale (i.e., as if they all started up in the same month), then calculate the average monthly rate. Given the large amount of individual well data and the large month-to-month variability of individual well production, vintage plots are a common method to analyze average well performance trends.

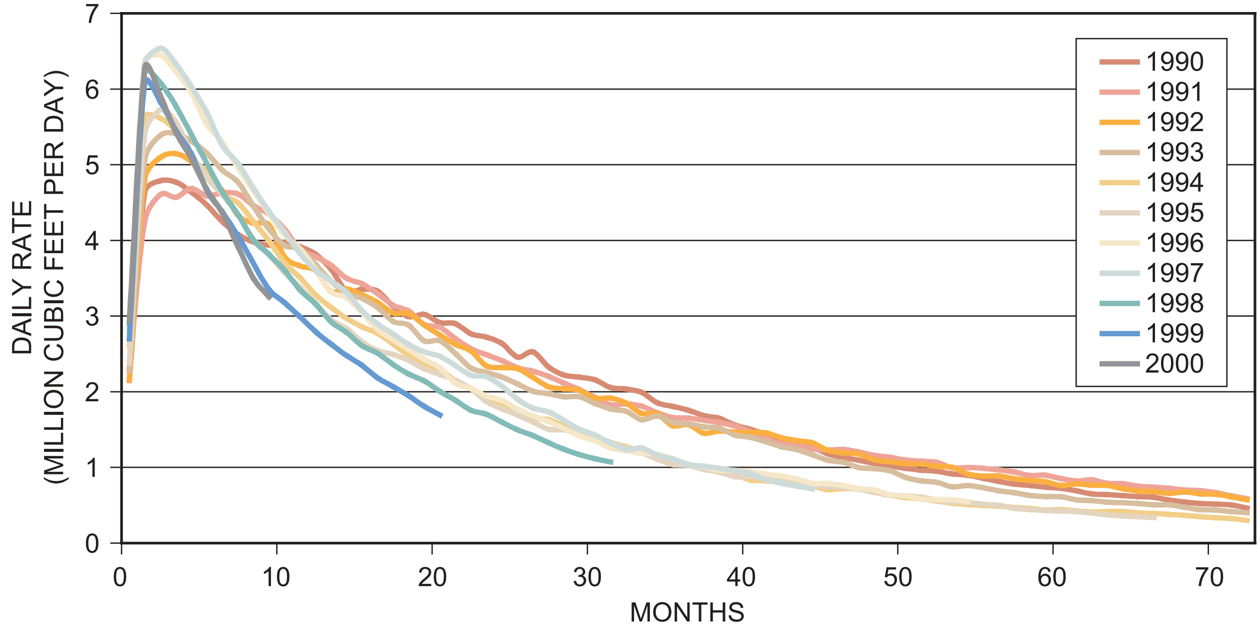
Using the GOM Shelf as an example basin and 1993 as an example "vintage" year, to construct a vintage plot would entail taking all connections that came on production in 1993. For each connection in this vintage, let time t = 1 be the first month of production (whether it happened in January or December), t = 2 be the second month, etc. If a connection was shut in for one or more months, skip those months. Add together the time normalized production profiles for all connections that started up in that vintage year and then calculate an average by dividing the profile by the number of initial gas well connections. This yields the average connection performance for the 1993-vintage connections in this basin. The average can then be analyzed using any of the usual decline analysis techniques; for example, rate vs. time plots or rate vs. cumulative production plots. (See Figures S4-148 and S4-149.)

Note that the average rate for a month is calculated by dividing the total normalized gas well production by the initial number of connections rather than the number of connections actually producing in that month. The reason is based on the purpose of the forecast – to be able to depict how the average gas connection performed over time. Use of the operating connection count would yield an optimistic answer – as time progresses, there will be fewer and fewer connections remaining, thus the average rate will be based only on the surviving (good) connections.

Rate vs. time plots and rate vs. cumulative production plots are used to graphically illustrate the traditional production parameters for individual gas wells: (1) Estimated Ultimate Recovery, (2) Initial Production Rate, (3) Initial Decline Rate, and (4) Hyperbolic Decline Exponent.

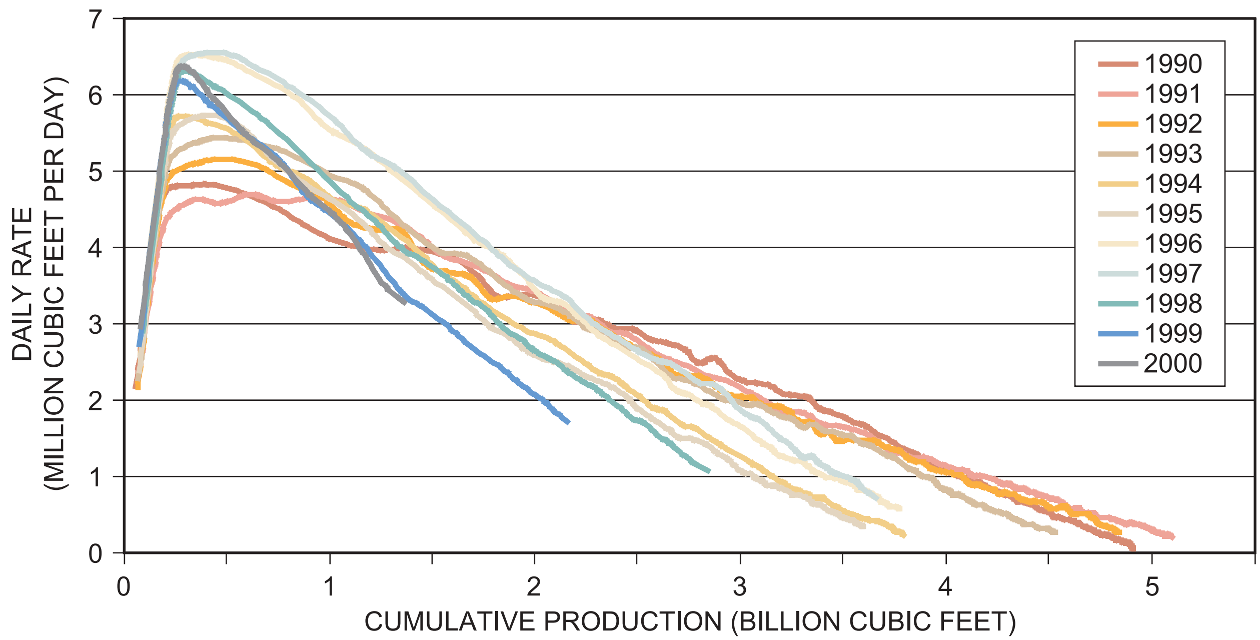
As mentioned above, well performance was analyzed as appropriate on a number of different levels: (1) Country (2) Region, (3) Basin, and (4) Formation. In addition, as appropriate within specific areas, analysis was performed on performance trends versus depth. Figures S4-150 and S4-151 are example plots showing two depth intervals in the Western Canada Sedimentary Basin.

Because of their unique production character and the large amount of recent drilling, particularly within



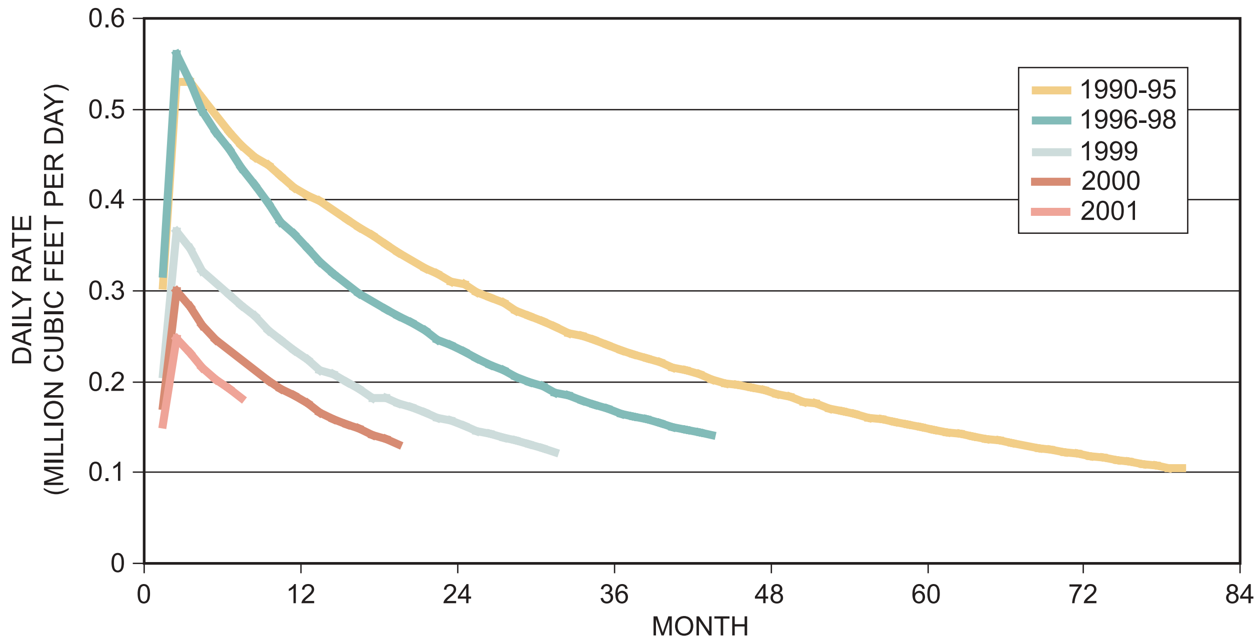
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-148. Gulf of Mexico Shelf Conventional – Average Daily Gas Well Production vs. Time, by Year of First Production



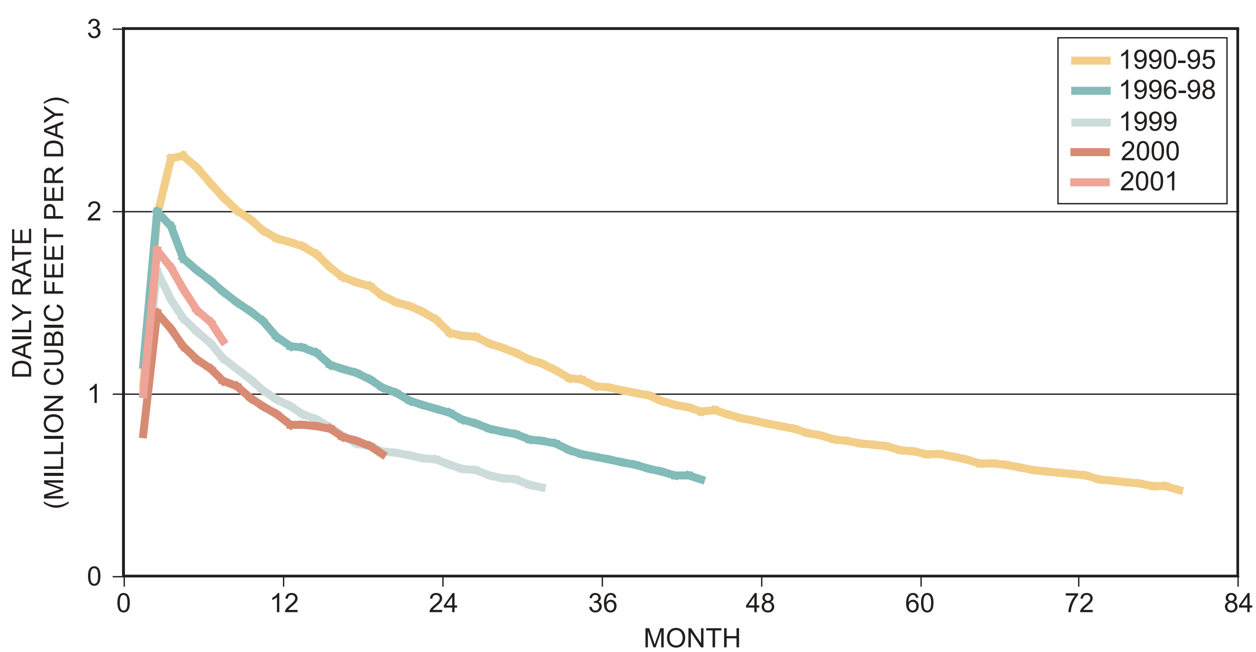
Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-149. Gulf of Mexico Shelf – Average Daily Gas Well Production vs. Cumulative Production, by Year of First Production



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-150. Western Canada Sedimentary Basin (0 to 5,000 Feet) – Average Daily Gas Well Production vs. Time, by Year of First Production



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-151. Western Canada Sedimentary Basin (5,000 to 10,000 Feet) – Average Daily Gas Well Production vs. Time, by Year of First Production the Powder River Basin, coal bed methane wells were generally segregated in the database and analyzed separately. As coal bed well response varied greatly between basins, the coal bed production was generally analyzed within a specific basin. (See Figures S4-152 and S4-153.)

1. Estimated Ultimate Recovery

Average Estimated Ultimate Recovery or EUR per connection were calculated within the GSR from normalized decline curves. This procedure was used for non-associated gas, and production from the Barnett Shale. A modified procedure was used for coal bed methane and the Antrim Shale. To calculate a normalized decline curve for each basin/formation of interest, the process is as follows:

1. Compile normalized Rate vs. Time plots for each connection vintage since 1990;

2. Average the vintage curves to produce a composite decline profile; and

3. Fit an Arps decline equation to the resulting normalized composite decline.

For coal bed methane and Antrim shale wells, the GSR utilizes an equivalent procedure as was used for more conventional wells. In addition, EEA has incorporated operators' published well production profiles and EUR estimates where available.

It is not generally possible to construct vintage plots for associated gas production, as most states report production on a lease basis, not on a per well basis. EEA sums associated gas production by basin and state, calculates an average production trend, and uses this trend to project future associated gas production. EEA does not attempt to quantify per well EUR or other performance parameters for oil and associated gas.

Curves for emerging plays were based on analogues from existing plays.

2. Comparison with Conventional Analytic Techniques

EURs and other decline parameters generated within the GSR were, on a regional basis, independently compared to decline parameters generated using conventional analytical techniques. Fetkovich type

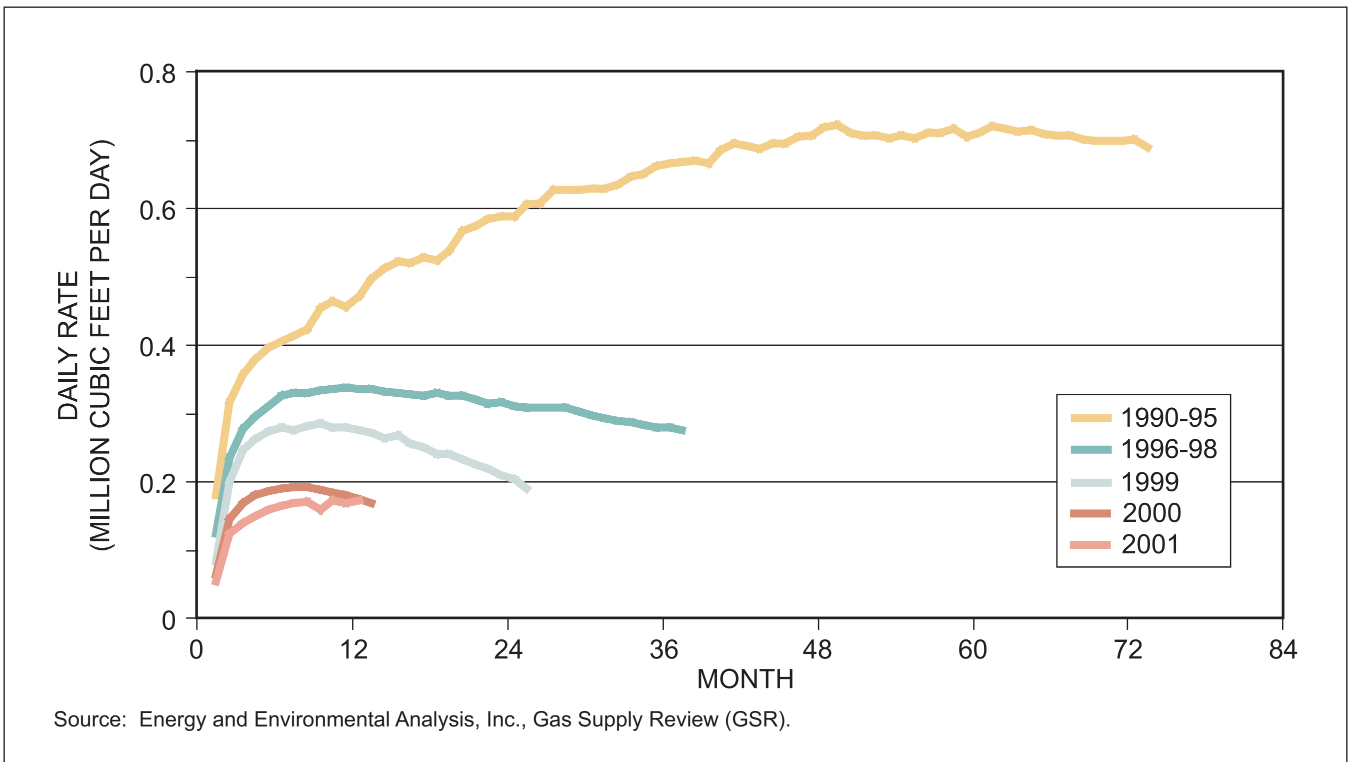
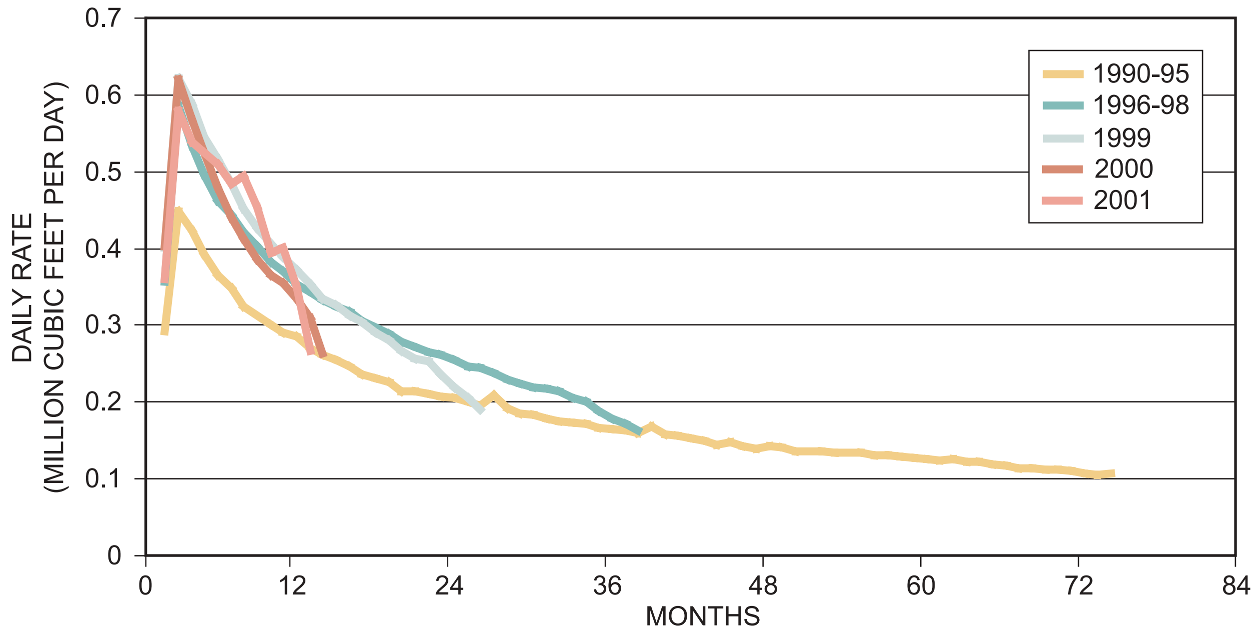


Figure S4-152. Rockies Coal Bed Methane –
Average Daily Gas Well Production vs. Time, by Year of First Production



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-153. Rockies Non-Coal Bed Methane – Average Daily Gas Well Production vs. Time, by Year of First Production

curves were used to estimate the EURs, IPs, initial decline constants, and the hyperbolic decline exponent *b*. Initial rates and initial decline rates were matched by year. Figure S4-154 shows a match for South Texas 1993 vintage wells. Generally, it was felt that the hyperbolic decline constant *b* was a function of large-scale reservoir properties (heterogeneity, layering, relative permeability) and would not be time-dependent. Although it is possible that a significant change in completion strategy would affect *b*, no indication of this was observed. Accordingly, *b* was determined from matching the oldest-vintage wells, which have the most production history. This *b* was applied to all vintages.

Note that the last year of data falls off-trend due to end-year effects (December 1993 wells have less production history than January 1993 wells). This data was excluded from the analysis. Each match was checked against rate-versus-time and rate-versus-cumulative plots to ensure a consistent forecast. In addition, note that due to lack of pressure data the Fetkovitch analysis was used only to estimate conventional (Arps) decline parameters. (See Figures S4-155, S4-156, and S4-157.)

EUR trends generated in the GSR program were cross-checked on a regional basis against EURs calculated using conventional decline analysis. As is shown in Figures S4-158 and S4-159 for the South Texas Gulf Coast region and Permian Basin, EURs trends calculated using conventional decline analysis while not exact matches, were in reasonable agreement with EURs calculated within the GSR.

D. Hydrocarbon Supply Model

The production performance parameters generated in the historical analysis were utilized either as direct inputs to the Hydrocarbon Supply Model (HSM), or to check HSM outputs.

1. Completions per Well

The historical production performance analysis was conducted within the GSR on actual per connection production data. Per connection EURs, IPs, decline rates, and decline constants were analyzed. In many regions, over time each wellbore may produce from a number of different completions. This effect can be significant in certain areas, notably the Gulf of Mexico.

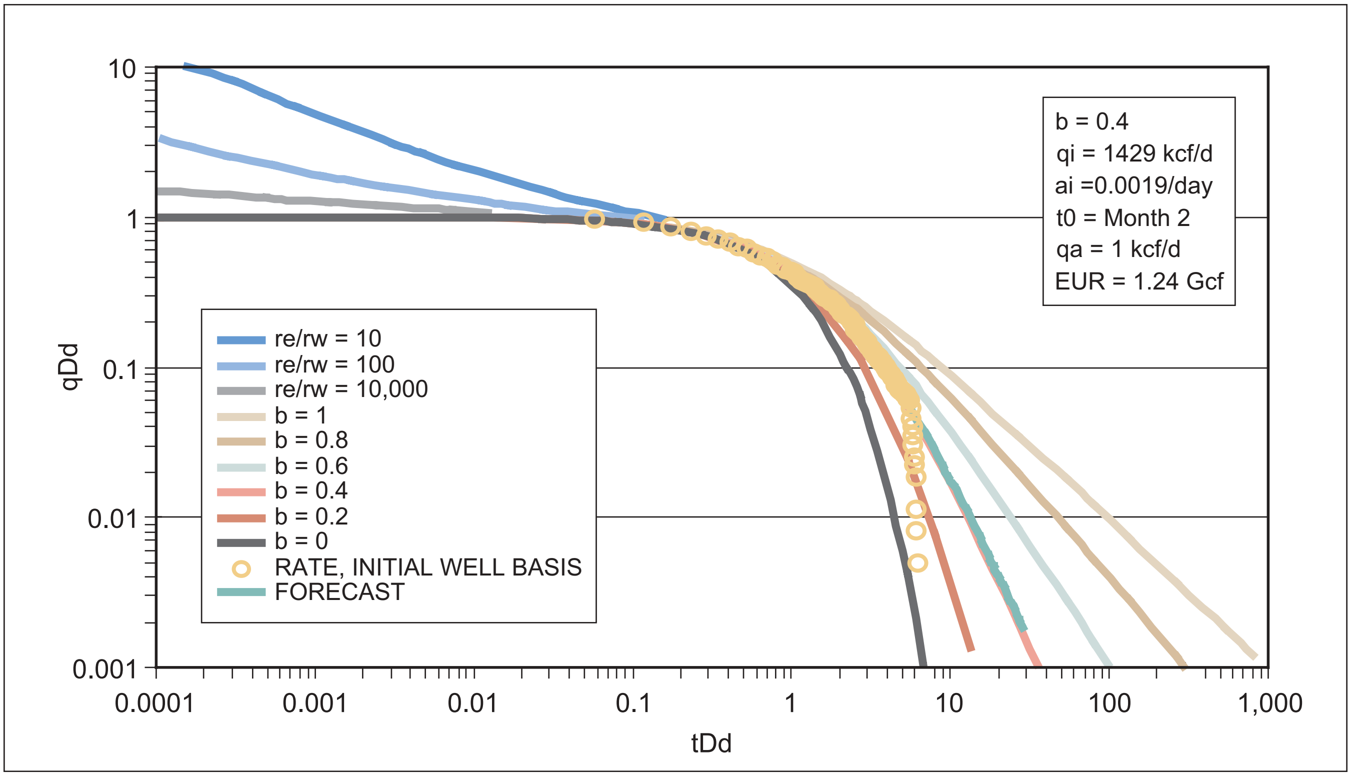


Figure S4-154. Fetkovich Type Curve Match –
South Texas Normalized Production, Vintage Year = 1993

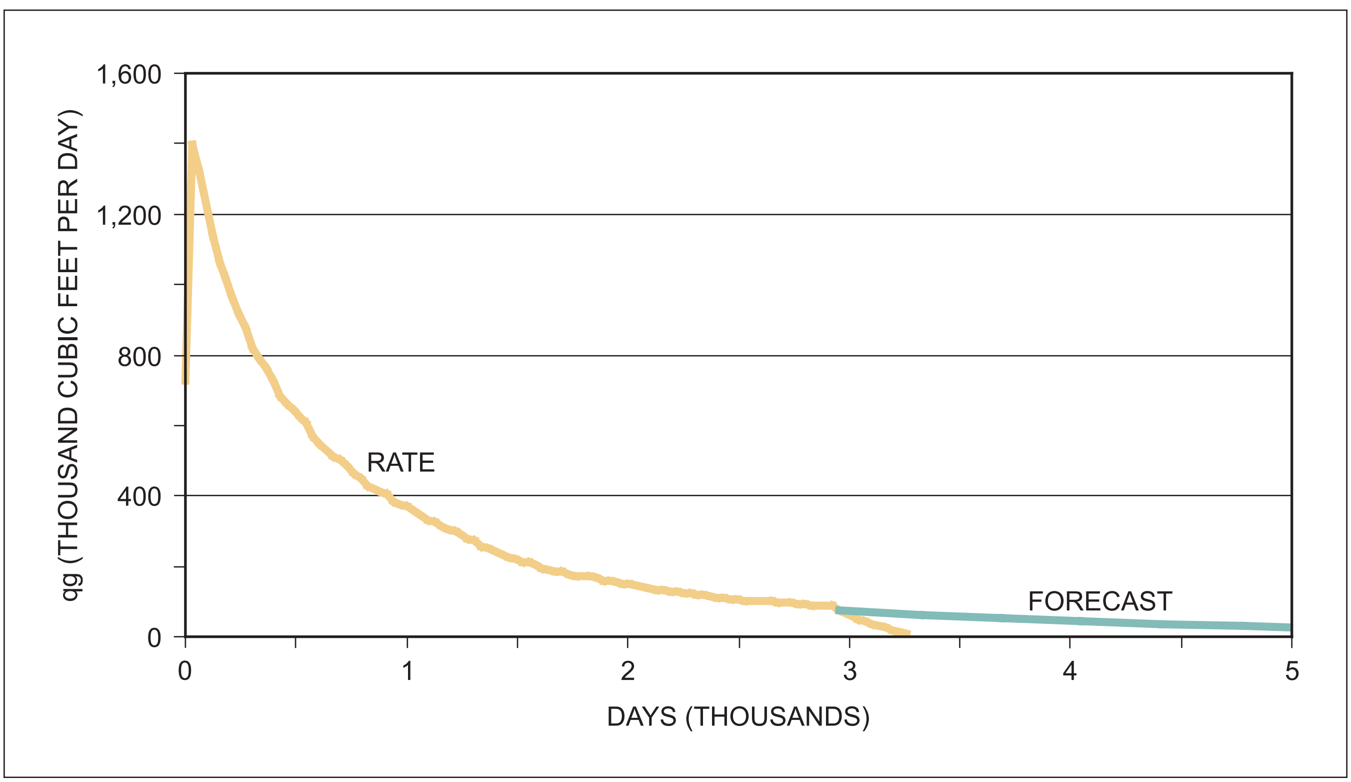


Figure S4-155. Cartesian (Rate vs. Time) Plot of Fetkovich Type Curve Match –
South Texas Normalized Production, Vintage Year = 1993

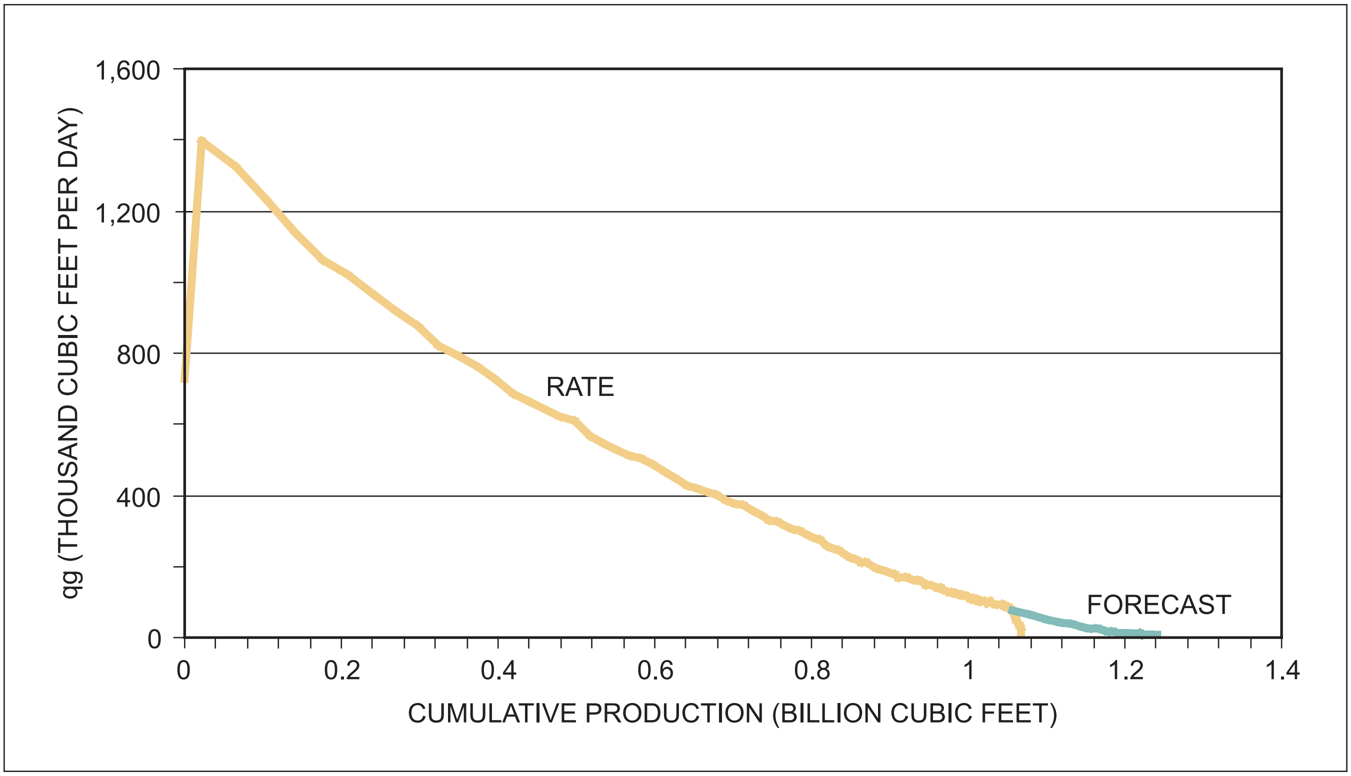


Figure S4-156. Rate and Cumulative Production Plot of Fetkovich Type Curve Match – South Texas Normalized Production, Vintage Year = 1993

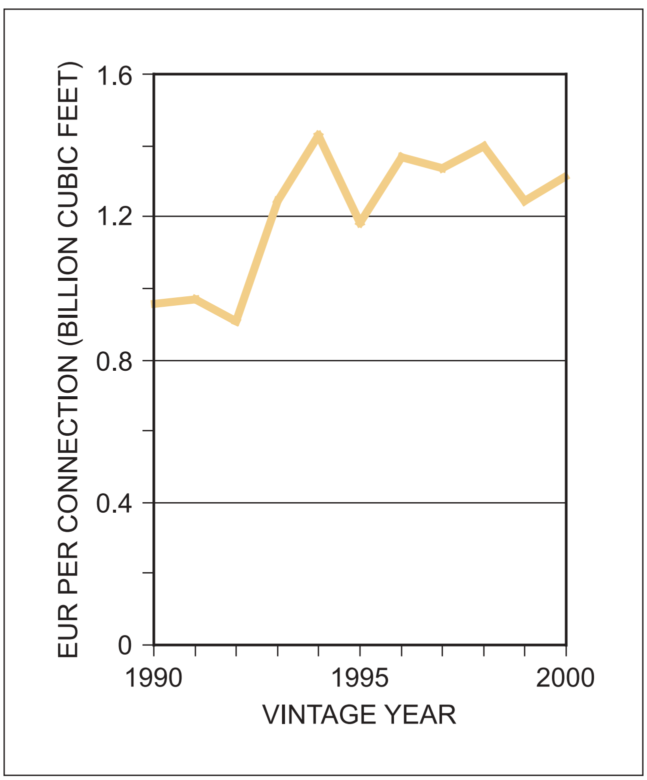


Figure S4-157. South Texas Gulf Coast – Trends by Vintage (Fetkovich Analysis)

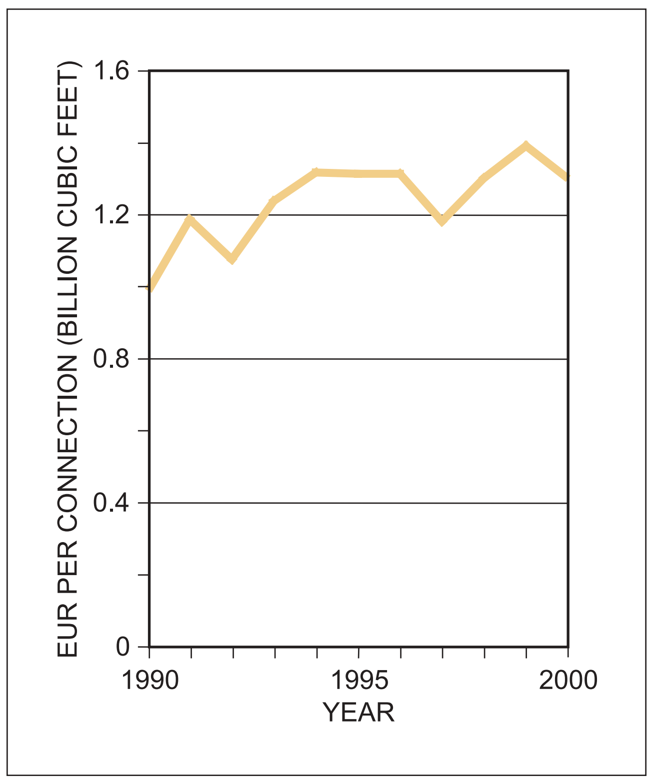


Figure S4-158. South Texas Gulf Coast – EUR per Connection, Wet Gas (GSR Analysis)

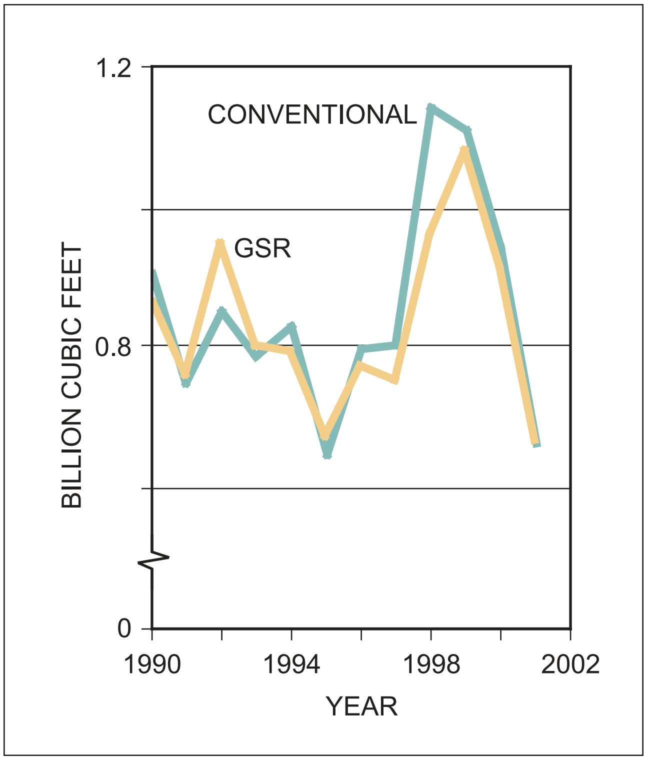


Figure S4-159. Permian Basin – Estimated Ultimate Recovery per Connection, Wet Gas (GSR Analysis)

Forecasts from the HSM model are based on the production properties of *wellbores, not connections.* Accordingly, there was a need to scale-up production properties from a per connection basis to a per wellbore basis. This was accomplished by analyzing historical completions per wellbore over time, and then extrapolating the historical data into the future.

Figure S4-160 shows an example of the historical and extrapolated data. The historical data plots the cumulative completion/recompletion history of wellbores from the initial completion date. Over time, completions per wellbore increases as up-hole reservoir targets are recompleted. Using the historical trends of completions per well per region, current and future trends of completions per well were extrapolated.

2. Base Decline: Proved Production Profile

Base decline profiles of gas well gas were generated directly from the IHS Production Database (May 2003 vintage) for the United States and IHS/Accumap (October 2002 vintage) for Canada. Base decline profiles were analyzed on two levels: (1) Country level – U.S. lower-48 and Western Canada, and (2) Region level – Permian Basin, GOM Shelf, South Texas Gulf Coast, etc.

The shape of the lower-48 and Canadian base declines were modeled using actual production data for all gas wells producing prior to January 1, 1998. Best-fit base decline curves honoring (1) actual production data and (2) proved reserves were determined using conventional decline analysis for the U.S. lower-48 and Canada. These overall country level base gas well decline curves were honored in the HSM model. (See Figure S4-161.)

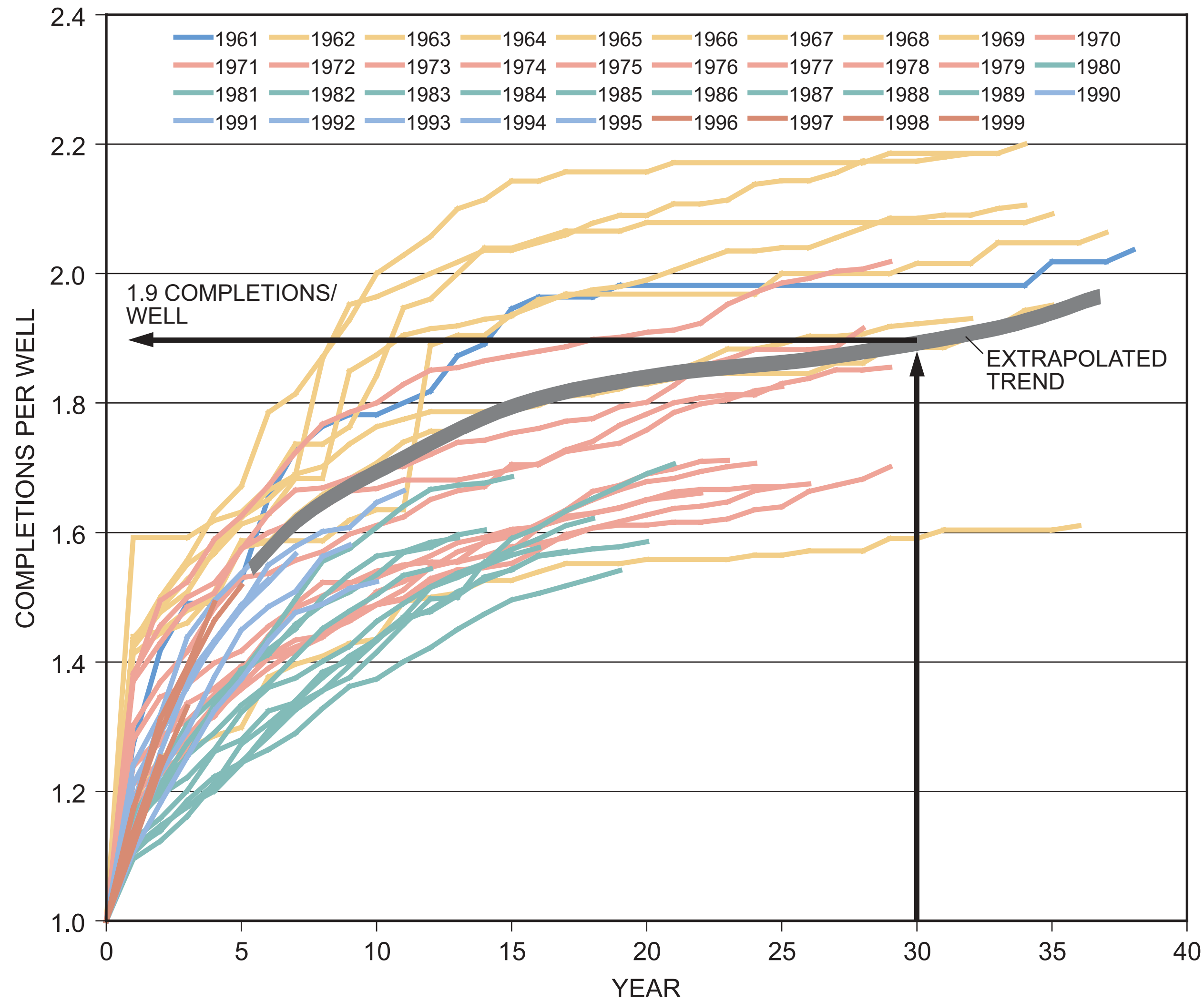
3. Proved Reserves and the Treatment of Non-Producing Reserves

Proved Reserves in the U.S. were analyzed utilizing EIA's "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves" and in Canada utilizing data published by the Canadian Association of Petroleum Producers (CAPP). Where required to analyze the data on a more granular basis, the EIA data was allocated to specific regions and basins by EEA as per below.

> EIA publishes proved reserves statistics by state and district (e.g., Texas Railroad Commission). In order to integrate the EIA reserves data into the HSM modeling framework, EEA apportioned the EIA state and district reserves into the HSM model regions and basins. EEA used two major sources of detailed reserves data to apportion the EIA reserves: (1) GSR completion-level producing reserves estimates, and (2) EIA reserves by Rocky Mountain basin published in the Department of Interior Rocky Mountain Land Access Study ("EPCA Study"). The GSR reserves were processed to generate a state/district to basin allocator matrix. The GSR derived allocators were then used to split the EIA state/district reserves into basins, honoring the EPCA Study basin figures as available.

Recent U.S. reserves data have indicated historically strong annual increases in non-associated gas reserves. As detailed in the 2001 EIA Annual Report "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves," a very significant percentage of the incremental reserve adds were in the category of Proved, Non-Producing Reserves.

At year-end 2001, lower-48 non-associated wet gas Proved Reserves totaled 160 TCF; 46 TCF, or almost 29% of those reserves were classified by operators as



Source: Energy and Environmental Analysis, Inc., Gas Supply Review (GSR).

Figure S4-160. Completions per Well (Gulf of Mexico Shelf)

Proved, Non-Producing Reserves. This is up from approximately 25 to 30 TCF of Proved, Non-Producing Reserves in the late 1990s.

The 46 TCF of Proved, Non-Producing Reserves includes what the industry commonly identifies as Proved Developed, Non-Producing (PDNP) and Proved, Undeveloped (PUD). The PDNPs are generally plugbacks in currently producing wellbores or wells waiting on pipeline or other infrastructure installation. The PUDs generally require additional wellbores or other capital facilities. (See Figure S4-162.)

As it was not possible to accurately distinguish PDNPs from PUDs in the data, the NPC assumed for modeling purposes that the 16 TCF of Proved, Non-Producing Reserve build-up over the last few years were in the form of PUDs, and would therefore require incremental capital to put on production. The remaining 30 TCF of Proved, Non-Producing Reserves were modeled as plug-backs which would not require incremental capital to bring on to production. These reserves were added to the Proved, Producing profile, in effect flattening the Proved decline curve.

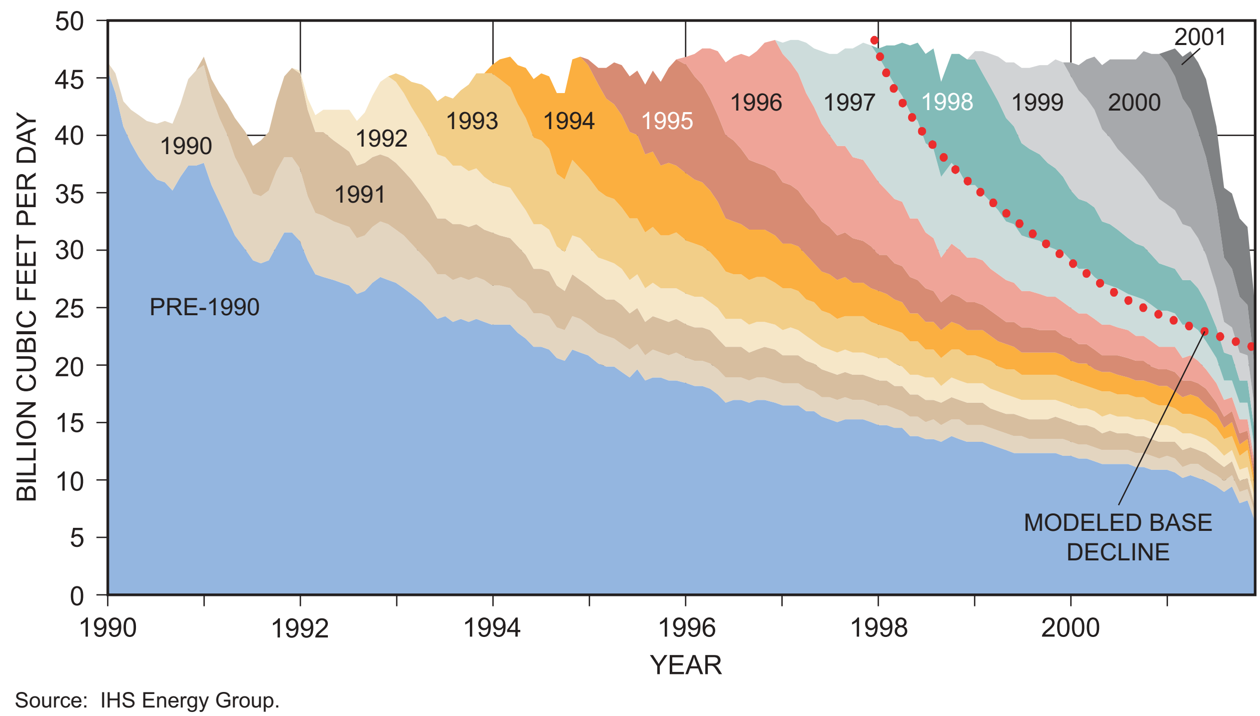


Figure S4-161. U.S. Lower-48 and Canada – Daily Wet Gas Production from Gas Wells, by Year of Production Start

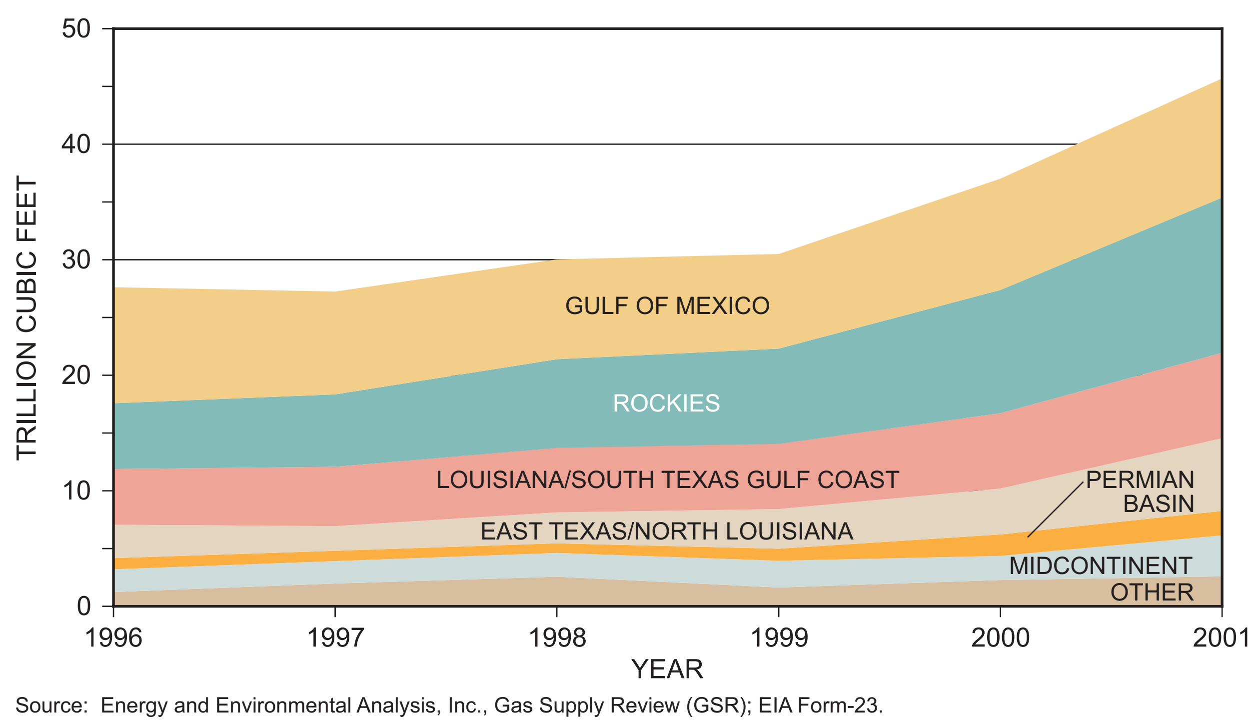


Figure S4-162. Non-Associated Non-Producing Gas Reserves

CHAPTER 5

TECHNOLOGY IMPACT ON NATURAL GAS SUPPLY

A Technology Subgroup under the Supply Task Group was formed with representation from various segments of the oil and gas industry to assess the role and impact that technology will have on natural gas supply in North America. Several workshops and meetings were organized to provide a forum for industry experts to discuss the role that current and future technology will play in sustaining the supply of natural gas. From this process, a forecast of technology improvement parameters was developed for input into the natural gas supply model used for the study. Also, various sensitivity cases were run to assess the effects of a range of high and low rate of advancement of technology development and application. Besides predicting technology impact for the model, several insights were developed during the course of the study from the Subgroup members and experts which will be highlighted in this report.

I. Key Findings

Technology improvements play an important role in increasing natural gas supply.

During the last decade, 3-D seismic, horizontal drilling, and improved fracture stimulation have had significant impacts on natural gas production in many basins in North America. Also, due to advanced designs in deepwater developments, additional production from the Gulf of Mexico slope regions has been realized.

In addition to these step-change technologies, continued improvements in core technical areas have been implemented as a result of industry's continuing efforts to search for more cost-effective ways to find, develop, and operate oil and gas fields. This trend is especially evident in the production of nonconventional gas reservoirs such as coal bed methane, shale gas, and tight sand formations. New designs in drilling bits, improved well planning, and modern drilling rigs have also lowered drilling costs in many regions. Advances in remote sensing, information technologies, and data integration tools have served to keep operating expenses in check.

As modeled in the Reactive Path scenario and illustrated in Figure S5-1, by the year 2025, advanced technologies contribute 4.0 trillion cubic feet (TCF) per year of the 27.8 TCF per year produced in the United States and Canada. This amounts to 14% of the natural gas produced during that year.

Adding new North American natural gas supplies will require finding, developing, and producing more technologically challenging resources than ever before.

Overall, when assessing the natural gas resources that will be found and developed over the next 25 years, they can be generally described as deeper, hotter, tighter, more remote, in deeper water and smaller, harder-to-find prospects. The combination of more difficult natural gas resources and higher prices should catalyze increased efforts in research, development, and application of new technologies by the industry and governments.

Many of the geologic plays in the Permian, Midcontinent, and Gulf Coast regions where significant resources are anticipated will tend to be deeper and consequently hotter than previously developed

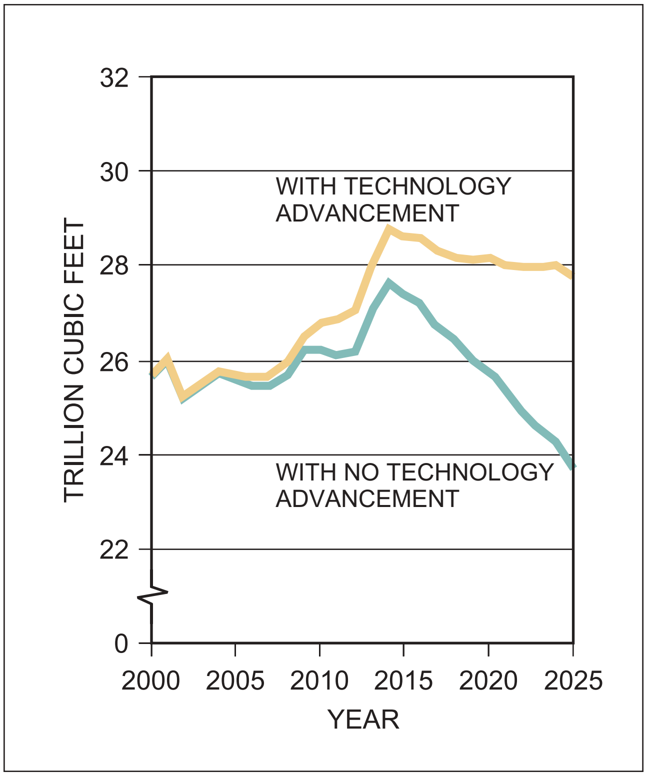


Figure S5-1. Impact of Technology on U.S. and Canadian Natural Gas Production

plays. This challenge lends itself to developing new drilling, logging, and completion equipment designed to deal with the increased depth and temperature. Also, further improvements in subsurface imaging technologies will help better locate and define the deeper reservoirs.

As more unconventional gas resources are developed, the average permeability of the producing reservoirs will continue to decrease, requiring the industry to find and apply new technologies and best practices that enable low permeable wells to produce at economic flow rates. The industry will be challenged to find methods to locate "sweet spots" in tight basin-centered gas fields, shale gas and coal bed methane reservoirs, thus reducing the number of marginally commercial wells being completed.

Also noted in the resource assessment, significant new natural gas reserves will be found and developed in remote locations such as the Alaskan and Canadian arctic regions. This, along with new resources in the deep waters of the Gulf of Mexico and Eastern Offshore Canada, will require the industry to develop technologies that will further reduce drilling and infrastructure costs, improve the success rate of exploration, as well as operating reliability and efficiency.

Future prospect sizes are projected to continually decrease over time, according to the resources assessment efforts in the study. Advancements in 3-D seismic acquisition and interpretation will be required to locate and appraise these smaller prospects. Improved wellbore designs to drain multiple smaller reservoirs with fewer wells will also be required.

The combination of more difficult natural gas resource and sustained higher prices of natural gas should catalyze increased efforts in research, development, and application of new technologies.

Investments in research, development, and application of new technology have declined over the last 10 years.

Although it is difficult to obtain information concerning how much the total oil and gas industry spends on technology improvements focused on North America natural gas assets, over the last decade the trend in upstream research and development spending has been downward, as reported by the U.S. major energy producers through the EIA (see Figure S5-2).

Forecasting future technology investment is difficult. As a result, the implication of technology improvements on production and prices are cast in terms of a range of outcomes as shown in Figures S5-3 and S5-4. The low advancement sensitivity case reflects a slower pace of technology development and application caused by reduced investment in research. The high advancement case reflects a faster pace of technology development and application. It is envisioned that the rate of which new technologies are developed and applied will fall within this range over the next 25 years.

Service industries and joint-sponsored research programs are playing an increasing role in research and development. This can be viewed as a cost-effective and less redundant method for research. It may also have the effect of slowing down the application of new technologies for the following reasons:

- Collaboration between the users (oil and gas exploration and production companies) and external

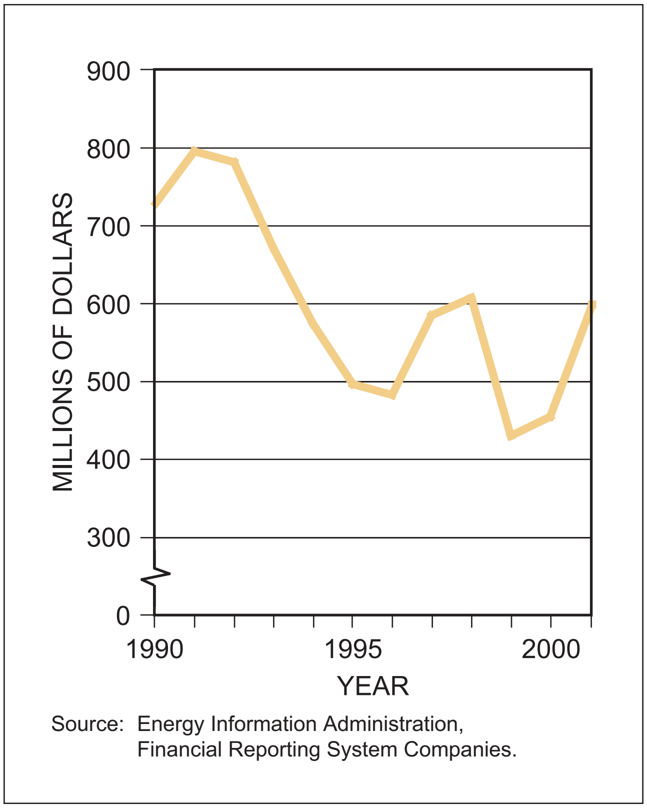


Figure S5-2. Upstream R&D Expenditure History

developers is often not as efficient as when the research was done within the user's own company.

- Users of technologies were more apt to attempt field trials of new technologies when internally developed. Today, the service industry or sponsored research programs are required to prove the effectiveness of new technology before it is adopted by the industry. This has developed into a "Catch 22" since the service sector does not have access to the necessary field assets to conduct the tests.

- New technology is being tested worldwide, particularly where the resource quality and the technology impact are higher. As a result, more new technologies are being field tested overseas as compared to previous years when most new technologies were tried and proven in the United States. One possible exception to this would be in the deepwater regions of North America where the size and scope of these projects compare with overseas projects.

Adding to the above, independent oil and gas E&P companies have an ever-increasing role in North American conventional and unconventional gas and are less likely to pursue far-reaching research activities

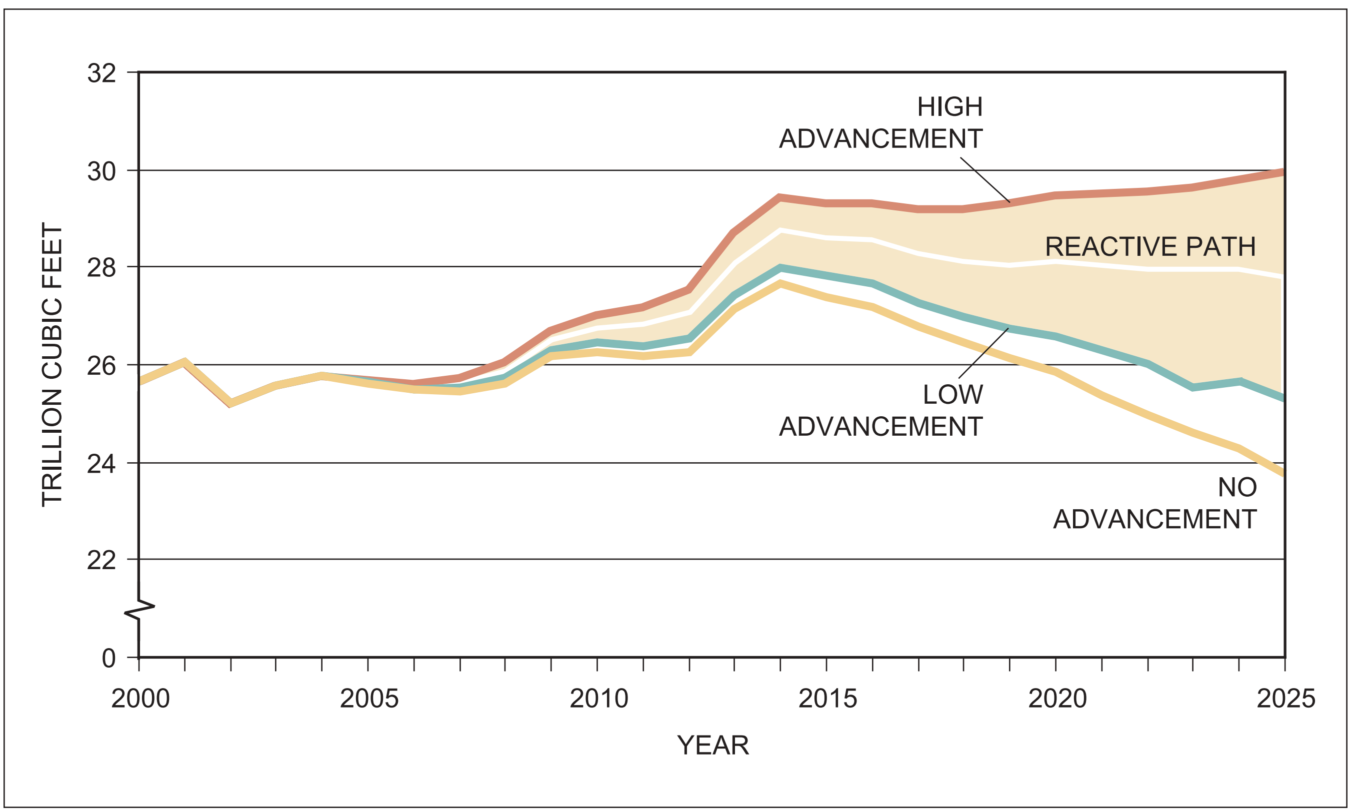


Figure S5-3. Impact of Technology Change on U.S. and Canadian Natural Gas Production

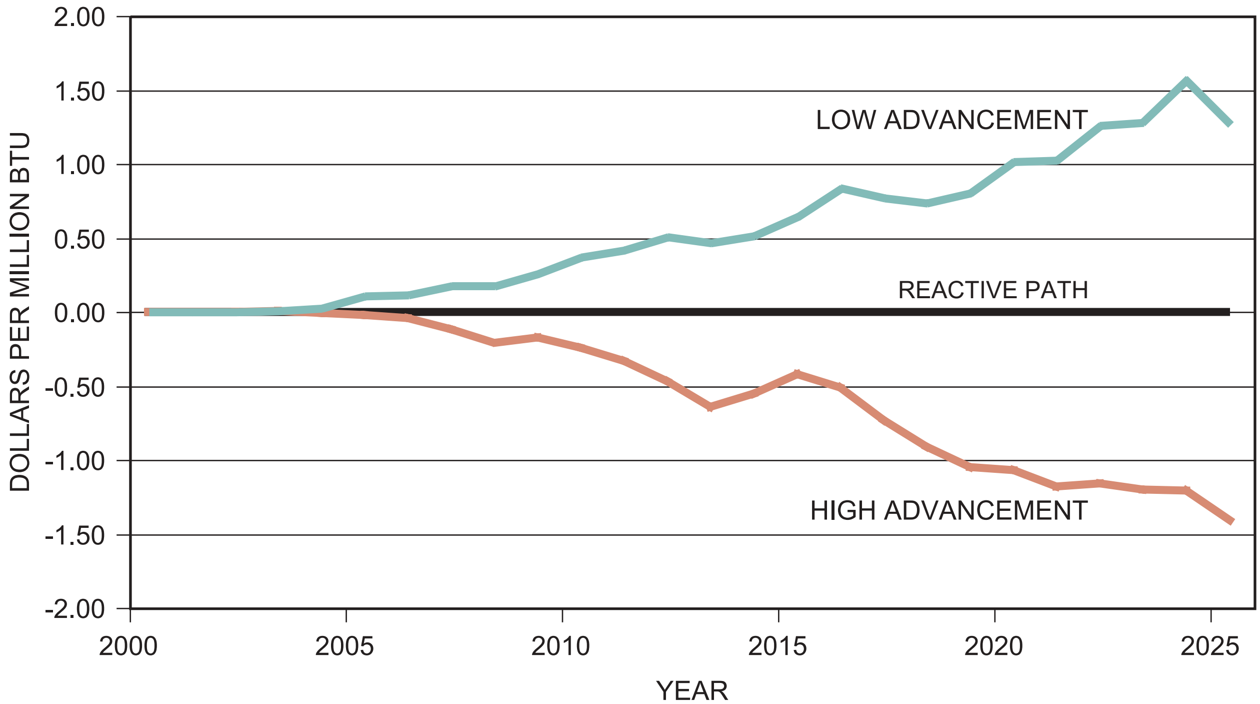


Figure S5-4. Impact of Technology Change on Price at Henry Hub (2002 Dollars)

than their major company counterparts. This pressures the service companies to fill the technology gap and/or causes research to gravitate toward a short-term focus. This focus impedes long-term or high-risk research, which may have a significant impact and be required for future gas supplies. In many cases, long-term or high-risk research has been relegated to joint industry and/or government-sponsored programs.

The gas exploration and production industry should collaborate more effectively with the Department of Energy in the planning and execution of complementary, not competitive, research and development programs.

The Department of Energy plays an important role in facilitating and sponsoring joint research and development programs within the gas supply industry. During fiscal year 2003, the Department of Energy plans to fund $47.3 million towards jointly sponsored natural gas technology research and development programs. This represents 53% of the funding allocated by DOE to sponsor oil and gas R&D programs, but only 9% of the total $529.3 million funds directed at fossil energy programs. As a comparison, coal research attracts $349 million in DOE funding. With the new insights developed from this study, the Department of Energy should address the obvious question of whether the current funding level towards natural gas research is appropriate in relationship to other R&D programs and the increasing challenges facing new natural gas resources within the United States (see Figure S5-5).

In addition to the question concerning the level of R&D funding for natural gas by the DOE, another important issue concerns whether the funds are focused on the right natural gas technologies. The DOE's role is to support the public interest in technology pursuits that industry is not adequately addressing. It is therefore essential that effective communication and collaboration exist between the DOE and the industry's technology developers to accomplish the DOE's role and prevent duplication. This is not an easy task since the developers are split among many entities, such as national labs, sponsored research organizations, gas producers, service companies, consultants, and universities. Figure S5-6 illustrates the allocation of DOE's technology funding among the various

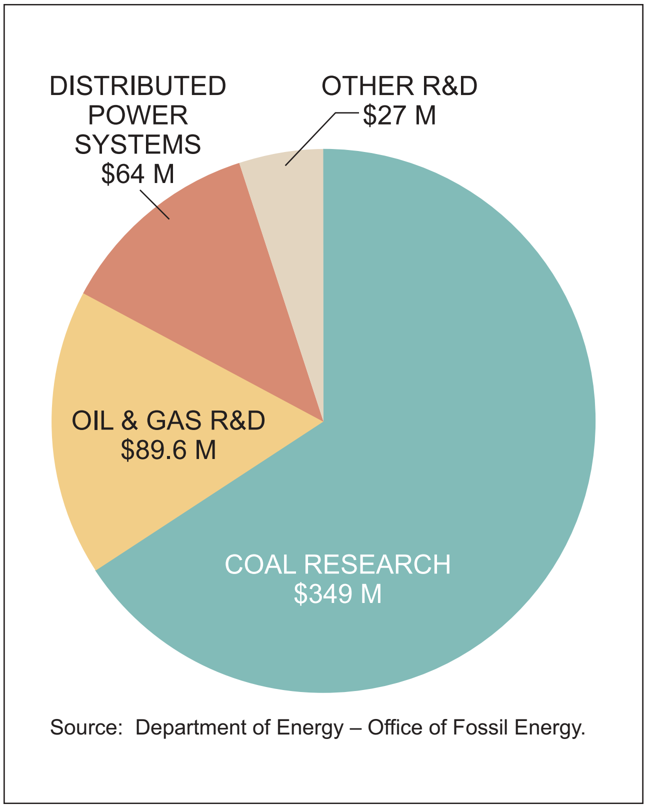


Figure S5-5. Comparison of DOE's Fossil Fuel Technology Funding by Fuel Type (FY 2003: $529.3 Million)

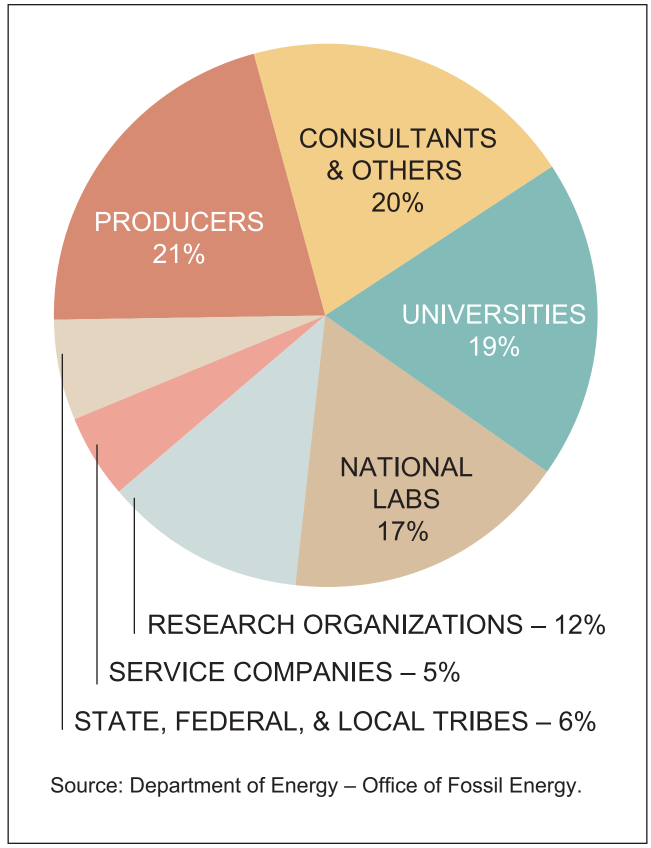


Figure S5-6. Upstream R&D Funding by Performer (FY 2002)

research and development entities. In addition, it is critical to have effective collaboration and communication by technology users to ensure mutual understanding of the problems to be solved and how effective application can be achieved.

Service companies have been hesitant to participate in jointly funded DOE-industry projects for the development and demonstration of advanced technology, assuming incorrectly that their proprietary advantages would be made public. The DOE and the service industry need to increase their discussions regarding future technology directions to ensure that the two do not duplicate efforts and to increase the opportunities for service companies to participate in government-supported technology development.

Environmental and safety concerns are significant drivers in the development and application of new technologies.

The oil and gas industry continues to focus a significant amount of technology development to address environmental concerns and reduce potential safety issues in the field. In some cases, these new technologies and approaches also contribute to improved operational performance. As an example, new smaller modular rig designs to reduce the environmental footprint also reduce downtime for rig moves improving the economics. Drilling and completing multi-lateral and long-reach horizontal wells reduce the number of well locations for equivalent reservoir drainage and simultaneously increases the recovery per well. Environmentally compatible drilling and completions fluids may reduce the cost associated with zero discharge requirements in certain sensitive areas. Designing rigs and equipment to reduce safety hazards such as automated pipe handling can also improve the drilling efficiency and shorten downtime while tripping in and out of the hole. As the industry and government regulatory agencies search for acceptable methods to access new areas and reduce costs of compliance with environmental and safety regulations, these advances in technologies may enable balanced solutions.

Professional workforce demographics – age, diversity, competency, and experience – will need to be effectively managed.

Because of the substantial hiring efforts during the oil boom of the mid-1970s to mid-1980s, the oil and gas producing industry is characterized by a skewed age distribution in its professional workforce of engineers, earth scientists and researchers. In North America, 40% of the oil and gas industry workforce is between the ages of 40 and 49. Around 30% of the workforce is between the ages of 50 and 64 and most of this 30% will likely retire in the next ten years, causing a substantial reduction in experienced professionals skilled in technology development, enhancement, and application. Some of the steps required to effectively manage this transition are:

- Increase the efforts to educate the public and promote the oil and gas industry to attract students of science and engineering to energy careers.
- Incorporate integrated information technologies, knowledge based systems, simulators, and visualization techniques to enhance the transfer of knowledge and experience from the departing "crew" to the new "crew."
- Take advantage of the new generation of workforce's advanced computer skills to accelerate acceptance of real time digital technology and data integration to enhance gas field performance and economics.

II. Defining Technology for this Study

To understand how advancements in technology impact the projected natural gas production in North America, it is important to understand how technology is defined. **For the purpose of the study, technology was defined broadly as any new or improved product, process, and technique that enhances the overall result compared with the current results observed today.** So technology, in this definition, not only includes new "tools" being developed and applied, but also incorporates advancement on the normal learning curve as the industry becomes more experienced in any given basin or methodology.

With regard to natural gas supply, several approaches and "tools" are employed to find, develop, and produce natural gas. It would be impossible to identify every combination of approach and technology currently being applied or attempt to empirically model further advancements in each combination of approach and technology. However, by using this broad definition, the Technology Subgroup, with the aid of several experts' experience and judgment, was able to forecast improvements in various input parameters that are important to the natural gas supply model and describe it as technology improvement.

III. Technology Subgroup Process for the Study

A. Scope

The Technology Subgroup was established to provide insights into the role and impact of upstream technology in delivering natural gas supply during the study period. Composed of thirteen members from a cross-section of industry organizations, the Subgroup established its scope to be:

- To design a methodology for measuring the impact of future technologies in the Hydrocarbon Supply Model
- To estimate the technology improvement parameters for the scenarios developed and a range of sensitivity cases
- To compose an upstream technology commentary for the final report that provides a current-state industry view of research and development, its impact on the outlook, and the role of technology in the future deliverability of North America natural gas through the year 2025
- To recommend actions that will facilitate the use of new technologies to improve the economics and increase the deliverability of natural gas.

B. Workshops and Special Technology Sessions

To achieve these goals, the Technology Subgroup scheduled a series of workshops, providing a forum to understand previous studies, provide input into the supply model, and prepare the report. In addition to the workshops, six special technology sessions were held to discuss with industry experts specific issues related to core, high-impact technology areas. The selected technology areas were Coal Bed Methane, Drilling, Completions, Subsurface Imaging/Seismic, Deepwater Development, and Natural Gas Hydrates. Held in January and February 2003, these special sessions enabled the Technology Subgroup to hear the views and foresights of a large cross-industry expert community, a total of 128 in all. These experts were helpful in addressing the effect of technology on future supplies and understand what challenges they face in developing new technologies. They also helped improve the quality of the technology input parameters for the supply model.

C. Methodology for Developing Technology Improvement Parameters for the Model

The Technology Subgroup reviewed the supply model to understand how the technology improvement is factored in the supply model. Some of the members attended the various regional resource assessments workshops to gain an understanding of current technologies being applied and challenges ahead. The Subgroup then reached consensus on the technology improvement parameters for the Reactive Path scenario for each assessment region and in some cases, by type of reservoir. The technology improvements parameters developed for input into the supply model are as follows:

- *Exploration success* – annual percent improvement in the ratio of completed versus non-completed exploration wells
- *Development success* – annual percent improvement in the ratio of completed versus non-completed development wells
- *Estimated ultimate recovery per well* – annual percent improvement in the estimated ultimate recovery (EUR) of natural gas per well
- *Drilling cost* – annual percent improvement in drilling costs per well, including site preparation, rig mobilization, drilling, and installing casing
- *Completion cost* – annual percent improvement in the completion cost per well, including perforating, stimulating, and installing down-hole production equipment
- *Initial production rate per well* – annual percent improvement in the initial production rate estimated in the model for each well completed
- *Infrastructure costs* – annual percent improvement in the major surface infrastructure costs associated with the development of new fields, such as offshore platforms, sub-sea production and gathering systems, field processing plants, and field gathering lines
- *Fixed operating expenses* – annual percent improvement in the operating expenses associated with the production of natural gas.

Three time periods were used to forecast the technology improvement parameters to model when technology application would likely change through the study period. They are as follows:

- *First five-year period* – 2003-2008
- *Second seven-year period* – 2009-2015
- *Third ten-year period* – 2016-2025.

In addition to the expert perspectives gathered at each technology special session, the Subgroup requested that the session participants agree to an industry consensus of the technology improvement parameters. Subsequently, the Technology Subgroup reviewed both the original set of input parameters and the set gathered in the special sessions to validate and determine the second generation reference-case improvement parameters. In most cases, the first assessment of parameters by the Technology Subgroup compared closely to the parameters developed from the special sessions.

Furthermore, two cases of improvement parameters, beyond the reference case, were generated to create a range of possible outcomes for technology impact in the supply model. The two cases were:

- High pace of technology advancement and application
- Low pace of technology advancement and application.

After reviewing the model runs, the input parameters were then checked for reasonableness and consistency with the expectations described during the discussions at the workshops and special sessions. Some modifications were made for the final model runs.

IV. Historical Perspective of Technology Contributions

The Technology Subgroup reached the consensus view that technology, as defined in Section II above, has historically contributed significantly to the ability for the petroleum industry to find, develop, and produce natural gas resources. If the industry relied on the same tools and methodologies used 30 years ago, it would only be able to produce a small fraction of what is currently being produced today. How much of an impact technology has had is difficult to precisely determine, because the industry does not routinely measure technology impact directly. However, one can find indirect evidence of technology's impact by looking at cost trends or production performance trends in any given area or field. Also, indirect evidence exists that identifies improvement in the ability of the industry to explore for natural gas. Most evidence, however, is anecdotal.

Over the last 15 years, extensive use of 3-D seismic technology has had a significant impact on the industry's ability to successfully explore for oil and gas in North America. In some basins such as onshore Gulf Coast and offshore Gulf of Mexico, clear and measurable increases in new discoveries and reserve additions can be attributed to 3-D seismic technologies. More recently, however, it has been observed that the number of new 3-D seismic surveys acquired has reduced and the overall impact from this technology has leveled off.

Advancements in drilling and completion technologies have improved penetration rates and enabled wells to be drilled in deeper horizons and deeper water at lower costs. Since the 1999 NPC study on natural gas supply and demand, the industry has demonstrated that it can drill and complete wells in water depths reaching nearly 10,000 feet. With the aid of new technologies and operator experience, this study is allowed to consider geologic plays out to the 200-mile U.S. boundary in the Gulf of Mexico adding to the technically recoverable resource base.

New approaches to fracture stimulation of wells drilled in tight gas reservoirs has substantially increased the production rate compared with wells drilled and fracture-treated a few years ago. Gaining the ability to measure formation properties while drilling, steering the wells more precisely, reaching out further in a horizontal direction and completing wells with multi-lateral configurations have allowed producers to more optimally place wells in the reservoirs and complete them for increased drainage. Also, the development of "smart well" technologies has equipped producing wells, primarily offshore, to obtain real-time bottom-hole information on the wells, as well as have the ability to control down-hole fluid entry without costly intervention of the well.

The application of these new approaches to drilling and completing wells may not have progressed as rapidly as some experts would have expected. This may be because (1) producers are not yet convinced the life-cycle production and/or potential increases in ultimate recovery justify additional upfront costs associated with applying the new technologies and/or (2) the maturity of technology application carries incremental risk of mechanical failure, causing the producers to be more cautious before attempting their application.

There have been remarkable improvements in platform and processing designs for deepwater developments which has allowed the industry to economically develop smaller fields in deeper waters with greater facility reliability. Similar improvements have also resulted in a decline in development costs in other historically high cost areas such as the Arctic regions of Alaska and Canada.

The phenomenal advances in information technologies, computer applications, along with advances in remote sensing and control systems have allowed the producers to gather and evaluate information more quickly, address their problems and opportunities in a more integrated perspective with enhanced visualization techniques, and operate fields more efficiently with less workforce. All of these advancements have contributed to overall improvements in solving technical and operational problems, making better business decisions, and reducing costs.

V. Projected Technology Improvements

Even with the noted technology advancements, over the last ten years investments in upstream research and development have declined and the industry has been cautious in using high-cost, high-risk technologies regardless of their potential. This reluctance is particularly evident if the technology is perceived to have a longer-term impact. With this observation and the maturity of the exploration and production environment, the Subgroup postulated that technology will play a somewhat lesser role in gas resource enhancement in the near future. Technology will gain slight momentum beyond five years as the industry invests more in technology developments, motivated by the challenges of the resources and higher gas prices. This is not intended to imply that there will not be continued improvements. Indeed, there will be continued improvements in both tools and techniques, but there are no foreseeable major breakthroughs on the horizon.

With this back-drop, the Technology Subgroup developed a series of technology improvement parameters for the Reactive Path scenario in the supply model that reflect the anticipated rate of improvement in each major core technical area of application.

Different improvement parameters were determined for each major geologic region, and in some instances, the type of reservoir, as for example coal bed methane or deep, high-temperature, high-pressure reservoirs. Also, to reflect the anticipated behavior of the industry, different improvement parameters were adopted for each of the different time periods, 2003-2008, 2009-2015, and 2016-2025+. The consensus of the members of the Technology Subgroup was that for most of the technical areas and geologic regions, the later time periods would probably see a faster pace of improvement than the early time period.

The actual technology improvement parameters used in the Reactive Path supply model are provided on a CD-ROM that is available with this report. However, in order to get a sense of the magnitude of these improvement parameters, Table S5-1 summarizes the improvement parameters by averaging them for each parameter.

The values shown in Table S5-1 were not calculated from any theory or formula. Instead, the values were determined by the Technology Subgroup, using all available information and insights generated during the study. The parameters were based more on collective experience and intuition, than on theory. However, the Technology Subgroup agreed that the parameters seem reasonable given all of the discussions developed at the workshops and special technology sessions.

It was appropriate to also look at a range of parameters that reflect a high and low pace of technology advancement and application. The Technology Subgroup developed parameters for these two additional

Technology Area	% Annual Improvement*	% Improvement Extrapolated for 25 Years
Improvement in Exploration Well Success Rate	0.53	14
Improvement in Development Well Success Rate	0.41	11
Improvement in Estimated Ultimate Recovery per Well	0.87	24
Drilling Cost Reduction	1.81	37
Completion Cost Reduction	1.37	29
Improvement in Initial Production Rate	0.74	20
Infrastructure Cost Reduction	1.18	26
Fixed Operating Cost Reduction	1.00	22

* These numbers reflect the average of the parameters, not the actual parameters in the supply model.

Table S5-1. Technology Improvement Parameters for the Reactive Path Scenario Supply Model cases, which are provided on the CD-ROM. Again, for the purpose of understanding the relative magnitudes and comparison between cases, these parameters are averaged and shown in Table S5-2.

As illustrated in Tables S5-1 and S5-2, not all technologies are expected to advance and improve performance at the same pace. It is expected that technological advancements in drilling, completion, and infrastructure will decrease costs at a higher rate than the improvements in exploration success rate. The lower parameter for exploration success reflects the flattening trend in 3-D seismic technology application and advancement. Also, moderate improvements from technology are anticipated in the area of increased ultimate recovery and operating expense reduction. In the high pace case, it is anticipated that the industry will focus more on improving ultimate recovery per well, and be willing to apply more advanced and somewhat more expensive drilling and completion technologies to achieve that result. Thus, the improvement parameters for the high pace case yield higher incremental improvement in EUR per well than the incremental improvement in cost to drill and complete wells. For the low pace, the improvement parameters are generally about half of the Reactive Path scenario.

VI. Summary of Special Sessions on Technology

The insights from the special technology sessions are summarized below. Although, separate special sessions were held around specific technology areas, these technologies were discussed in an integrated fashion at the Technology Subgroup workshops in order to understand their interrelationship.

A. Coal Bed Methane

Coal bed methane (CBM) is perhaps one of the best examples of how technology can have an impact on the understanding and eventual development of a natural gas resource. While gas has been known to exist in coal seams since the beginning of the coal mining industry, only since 1989 has significant gas from coal seams been produced and sold (Figure S5-7).

Technology Area	High Pace		Low Pace	
	% Annual Improvement*	% Improvement Extrapolated for 25 Years	% Annual Improvement*	% Improvement Extrapolated for 25 Years
Improvement in Exploration Well Success Rate	0.87	24	0.08	2
Improvement in Development Well Success Rate	0.87	24	0.13	3
Improvement in Estimated Ultimate Recovery per Well	1.49	45	0.23	6
Drilling Cost Reduction	1.60	49	1.02	23
Completion Cost Reduction	- 0.83	-19	0.34	8
Improvement in Initial Production Rate	1.13	32	0.24	6
Infrastructure Cost Reduction	1.73	35	0.63	15
Fixed Operating Cost Reduction	1.52	32	0.44	10

* These numbers reflect the average of the parameters, not the actual parameters in the supply model.

Table S5-2. Technology Improvement Parameters for High Pace and Low Pace of Technology Advancement and Application

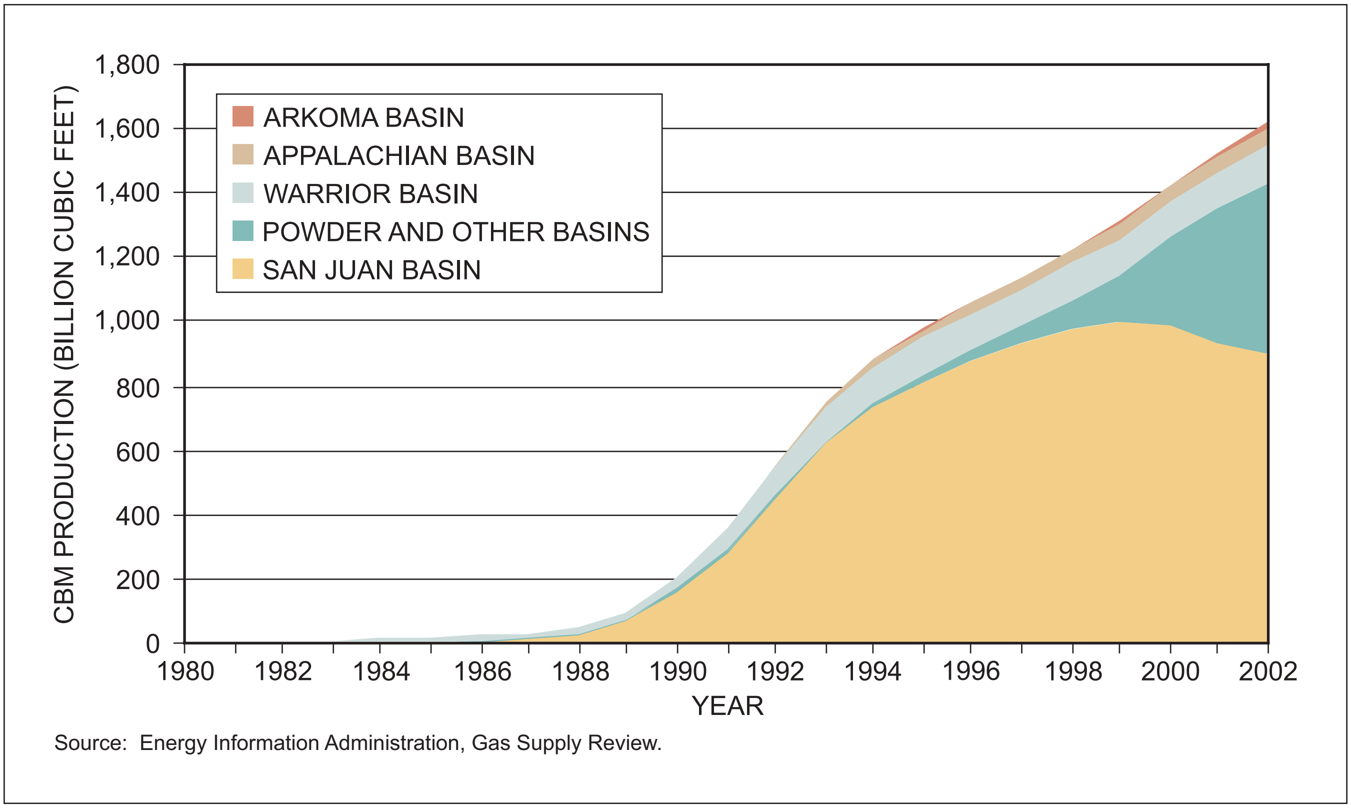


Figure S5-7. U.S. Gas Production from Coal Seams

Coal bed methane is a resource that was drilled through and observed for many years yet never produced and sold. New technology and focused CBM research ultimately resolved the resource complexity riddle and unlocked the production potential. Coal bed methane now provides over 1.6 trillion cubic feet (TCF) of gas production per year in the United States. This rapid increase from essentially zero in 1989 was accomplished through concerted efforts to assess the resource and understand the many reservoir properties controlling production. New well construction technologies and methods were also developed.

To determine the potential and need for additional CBM technology in the future, the Technology Subgroup conducted a special session with industry experts to identify technology needs and quantify technology change over the next 25 years. Six major areas were identified as important for future CBM development (Table S5-3).

During the special session on coal bed methane, and subsequent Technology Subgroup workshops, technology improvement parameters for coal bed methane were developed for input into the supply model around coal bed methane. These parameters also apply to natural gas produced from shale formations, like the Antrim Shale in Michigan.

CBM operators in general felt that CBM technology would continue to develop at a significant pace and that technology from other oil and gas disciplines (i.e., well drilling, gas production) would continue to be effectively adapted by CBM operators. In particular, the potential for future development in Western Canada and new basins in the United States (new to the CBM industry) as a result of better resource understanding and application of new CBM technology is believed to be significant.

B. Drilling Technologies

The oil and gas drilling industry is currently operating in a mature environment. The equipment and procedures for drilling and producing hydrocarbons are much the same as what existed 25 to 30 years ago. In addition to promoting new drilling technology, North American drillers have directed their time and talents in capturing and implementing "drilling best practices." These "best practices" have made dramatic

Technology Area	Technology Needs
Multi-zone well completion	• Technology for construction of fishbone well patterns • Directional control within thin coal formations
Smaller well footprint	• Ability to drill and produce CBM wells on small surface locations • Technology allowing greater well spacing
Rapid technology transfer	• Information technology including use of the internet to rapidly share and disseminate best practices
Produced water technology	• Technology and understanding of issues related to changing produced water from a waste to a valued resource
Improved gas recovery per well	• More effective well stimulation techniques • Completion designs to enhance drainage • Down-hole fluid separation/injection and compression and power generation to maximize well performance
Technology integration – development planning	• A systematic approach to developing a CBM field integrating all technology needs development, including the ability to evaluate coal seams prior to completing wells • Effective methods to simulate coal bed performance

Table S5-3. Major Areas for Future Coal Bed Methane Technology Improvements

improvements in: (1) drilling safer, (2) drilling with less damage to the reservoir and less impact on the surface environment, (3) improving rig mobilization, and (4) drilling with less rotary drill time. All of these practices have improved as operators seek to lower their hydrocarbon finding cost and improve production performance of the wells.

To determine the challenges and technology needs in the area of drilling needs, the Technology Subgroup conducted a special session with industry experts to identify technology needs and quantify technology change over the next 25 years. Five major areas were identified as important in the area of drilling technologies (Table S5-4).

During the special session on drilling technologies, and subsequent Technology Subgroup workshops, technology improvement parameters were developed for input into the supply model. These parameters took into account the expected advancements in specific drilling technology areas and the forecasted behaviors of the industry based on experience from the experts attending these meetings.

C. Well Completion Technologies

Well completions are a key step in the success of oil and gas production. A wide range of technologies and practices are associated with well completions. The trends of future wells will be deeper, more complex and in harsher environments. These trends will require more complicated completions over time. From the discussions at the sessions, five technology areas concerning well completions appear to be the focus of the industry to improve natural gas supply. These areas and their corresponding technology needs are summarized in Table S5-5.

During the special session on well completion technologies, and subsequent Technology Subgroup workshops, technology improvement parameters were developed for input into the supply model. These parameters took into account the expected advancements in specific well completion technology areas and the forecasted behaviors of the industry based on experience from the experts attending these meetings.

There will continue to be counter-forces in play as completion technologies are developed and applied.

Technology Area	Technology Needs
Rig designs to reduce "flat-time," and provide safer, environmentally friendly operations	• Small modular rigs with state-of-the-art pump equipment, automated pipe handling, and control systems • Casing drilling, coiled tubing drilling • Environmentally friendly drilling fluids • Multi-lateral with long-reach horizontal configurations to reduce number of surface locations
Deeper, high temperature/high pressure wells	• Develop drilling equipment and electronic sensors that can withstand the high temperature and pressure regimes • Expandable pipe to reduce weight and number of casing strings • Micro technologies to reduce size of equipment and allow smaller diameter wells
Deep wells drilled in deep water	• Expandable casing • Light-weight composite pipe • Dual gradient fluid systems • Lighter, smaller rigs capable of drilling in deeper water at greater depths
Low recovery wells	• Multi-lateral to increase effective drainage • More durable, high penetration rate drill bits for harder rock formations • Laser drilling
High cost exploration wells	• Micro technologies to reduce wellbore diameter requirements • Down-hole sensors for real-time measurements while drilling and steerable drilling

Table S5-4. Major Areas in Drilling Technologies

For example, smaller pool sizes and more severe subsurface environments will drive the industry to reduce completion cost, yet the desire to maximize well recoveries and extend the reliability of the well will drive completion costs up. The industry will continue to address these issues by evaluating the overall value proposition of the additional costs associated with the more advanced wellbore designs. It is anticipated that these new approaches to wellbore completions and designs will gain more acceptance over time, with more experience and as the value is realized. These concepts are assumed in developing the parameters for the high technology advancement sensitivity case in the model where higher rates of improvement in well recoveries are realized with only moderate improvements in drilling and completion costs.

D. Subsurface Imaging Technologies

The current view of the seismic industry can best be characterized as a paradox. The field is rich with significant new ideas concerning acquisition hardware, processing, and interpretive technologies. The industry has realized significant contributions from 3-D seismic technologies. Unfortunately, the financial state of the seismic industry is extremely poor at this time. As such, many of the recent technology developments are being severely delayed or even dropped in the short term. As a result, the improvement parameters used in the model that are used to calculate the success rate in drilling exploration or development wells are noticeably lower than the other technology improvement parameters. They are also significantly lower than the parameters used in the

Technology Area	Technology Needs
Improved recovery efficiency	• Improved stimulation technologies for higher initial production and more effective drainage • Multi-lateral and multi-zone completion technologies to maximize recoveries with fewer wells • Real time bottom-hole measurements to monitor well and reservoir performance • Improved perforating technologies for deeper, more-effective penetrations • Down-hole controls to prevent water influx • Down-hole fluid separation/injection and compression and power generation to maximize well performance
Deeper, high temperature/ high pressure wells	• Completion equipment and electronic sensors that can withstand the high temperature and pressure regimes • Expandable pipe to allow for larger bottom-hole production equipment without adding number of casing strings • Drilling and frac-fluids that maintain their properties at high temperatures
Deep wells drilled in deep water	• Expandable casing • "Smart well" technologies to enable the multi-zone completion and controls while preventing costly future well intervention
Tight sands	• Improved fracture stimulation
Low recovery wells from small pools, thin sands, low porosity	• Technologies focused on reducing cost per mcf • Bottom-hole compression increase production of low pressure reservoirs • Multi-lateral, steerable, extended reach wells to maximize reservoir wellbore exposure to the reservoir

Table S5-5. Major Areas in Well Completion Technologies

previous NPC studies, which projected continued rapid improvements as seen in the earlier part of the 1990s.

The seismic industry has been severely affected by acquisition overcapacity and a finite number of prospect basins to survey. Additionally there has been an overall reduction in internal expenditures for R&D by the operating companies. Data from IOGCC (2002) show reductions of 30% in R&D spending over the last six years by major producers. With the decline in revenue associated with speculative data, the service companies have reduced their total R&D spend by more than 25%, although they have maintained a constant R&D spend as a percent of revenue.

It is noted that the number of new basins or areas in which the advanced 3-D seismic technology has not been applied is rapidly shrinking. It is unlikely that anyone will re-shoot over existing data areas until there is a major improvement in data quality and resolution, which will not occur until there are profits to cover the development and investment. A bit of a "Catch 22," this is expected to take at least four to five years to work out of the system.

Despite the current seismic industry financial difficulties, there is no shortage of ideas on how to improve seismic technology for both exploration and production applications. If implemented, these enhancements could further reduce the risk in drilling (currently at approximately 40% success rate), improve our ability to differentiate hydrocarbon strata in the subsurface, and monitor the effectiveness of our resource extraction plans. These technology areas and needs were discussed at the special session on subsurface imaging and are highlighted in Table S5-6.

The improvement parameters developed for the model and sensitivity cases are provided on the CD-ROM. Again, they reflect a more conservative view on the industry's ability to improve success rates of exploration and development wells, based on the above discussions.

The industry is still waiting for the next technology breakthrough of the magnitude the industry experienced when 3-D seismic became available. It is unclear what the next major technology breakthrough will be. One possible breakthrough would be the ability to accurately detect "sweet spot" areas of unconventional gas plays which are typically found by pattern drilling. By finding these sweet spots ahead of drilling, the number of poor performing, sub-economic wells would be reduced, thus improving the overall economics of the program and creating an incentive for more participation. It would also reduce the overall number of wells/drill-sites in a given geologic region, yet maintain the same overall recovery. This would create a more environmentally attractive development plan.

E. Deepwater Development Technologies

The development of deepwater oil and gas projects will be critical to the natural gas supply in the study period, 2003 to 2025. It is estimated that 244 TCF of technically recoverable resources exist in the offshore regions of the Gulf of Mexico, most of which lies in deeper waters. Deepwater exploration and development activity commenced approximately 25 years ago, and since then, several significant oil and gas

Technology Area	Technology Needs
Seismic data acquisition and resolution	• Lower cost and less destructive approaches to acquiring seismic data • Further advances in data management to reduce costs • Ability to obtain seismic data while drilling • Single sensor recording to improve resolution and accuracy of the data
Interpretation	• Further enhancements in pre-stack depth migration to enhance the seismic images • Increased computational technologies to apply advance interpretation methods • Multi-component imaging to identify fluid properties in the reservoir • Method to identify "sweet spots" in unconventional gas plays
Reservoir monitoring	• Further enhancement of 4-D technology to find un-depleted areas of the reservoir • Permanent sensors for real-time measuring and reservoir monitoring
Integration with other technologies	• Ability to quickly integrate seismic information with earth and reservoir models to provide quick visual images to multi-disciplined teams for better decision-making approaches • Advanced visualization technologies to better understand the reservoir and create the digital gas field of the future

Table S5-6. Major Areas in Subsurface Imaging Technologies fields have been discovered and developed. During the past 10 to 15 years, significant technology advancements have been achieved to allow companies to drill and develop oil and gas in increasingly deeper water and deeper horizons. The next challenge will be to maintain the same exploration and development performance at less cost since it is anticipated that prospects will typically decline in size over time.

Long lead times for field development are not unusual in the deepwater Gulf of Mexico but have improved dramatically due to better technologies and relative proximity of new fields to existing infrastructure. Innovative designs in many aspects of drilling, completions, facilities, and processing have been introduced to enable the execution of deepwater development projects. Despite the complexity of these projects, deepwater technology records have been broken with relative frequency in the past five years. Currently, the deepwater record stands at:

- Deepest water depth drilled: 9,727 feet (Unocal Discoverer Spirit)
- Deepest subsea completion: 7,209 feet (Unocal Discoverer Spirit)
- Deepest moored operation: 8,009 feet (Shell Deepwater Nautilus)
- Deepest production capability: 7,200 feet for gas in the Gulf of Mexico
- Total drill-depth capability: 30,000 feet.

Advanced technology application must offer a relative value proposition to offset the risk of deployment in a high-cost environment. During the special session focusing on deepwater development technologies, the experts identified the key technology area and their respective needs as summarized in Table S5-7.

Several challenges remain for technology advancement in deepwater developments. Because of the size and scope of the discoveries, the industry has historically invested significant resources in developing technologies to address these challenges. A barrier to the progress of technology advancement is the reluctance of the operators to be the first to apply new

Technology Area	Technology Needs
Cost reduction while maintaining high environmental and safety standards	• Drilling and completion technologies noted in the previous sections to reduce costs • Further enhancements in platform designs • Enhanced subsurface imaging to improve the success rate of expensive exploration wells
Weight reduction for floating systems	• Light-weight composite materials • Subsea technologies for both producing and processing the fluids • Technologies to allow smaller processing equipment
Production reliability and flow assurance	• “Smart well” designs to provide downhole monitoring and control to reduce the need for re-intervention of the well • Subsea technologies to enable flow assurance and system reliability • Remote sensing and control systems to monitor and control facilities with reduce workforce on location
Reducing cycle time between discovery and first production	• Integrated technologies to model and simulate the field in real time fashion to allow multi-disciplinary teams to more effectively design the development and operations of the field • Advanced visualization technologies to assist in the design and operations of the platforms and facilities

Table S5-7. Major Areas in Deepwater Development Technologies technology due to the risk associated with deepwater developments. Therefore, many technologies new to the Gulf of Mexico are not new to the world. Technical challenges remain such as extreme water depths, unknown seafloor characteristics, ocean environments, and distance from infrastructure (facilities or pipeline).

It was the opinion of the Subgroup and experts that many opportunities lie ahead for new technologies and improved approaches in deepwater development. With this backdrop, the annual improvement parameters for deepwater drilling and developments are relatively larger than many of the other improvement parameters.

VII. Natural Gas Hydrates

The Technology Subgroup had the charge to investigate the technologies associated with natural gas hydrates and determine the feasibility of their contribution in the hydrocarbon supply model. To gather data on the subject of natural gas hydrates, a special session on natural gas hydrates was held on January 28, 2003, in Houston, Texas. The objectives of the workshop were to (1) determine if producing natural gas from gas hydrate deposits is feasible between now and the year 2025, and (2) to identify the technologies that are required to produce natural gas from gas hydrate deposits in North America. This effort to analyze the role gas hydrates may have is unique for this study compared to the previous NPC natural gas studies.

A. Conclusions from the Special Session

On the basis of the results of the special session, the following conclusions are presented.

1. Natural gas production from naturally occurring gas hydrate deposits should not be included as a major source of gas production in the NPC gas supply forecast before the year 2025. Their contribution as a significant supply of natural gas is anticipated beyond 2025.

2. Production from natural gas hydrate deposits in the deepwater Gulf of Mexico and other deepwater areas around North America will depend on both the development of appropriate technology and pipeline availability. Technology development will depend on the level of both government and private industry funding.

3. Production from natural gas hydrate deposits in the Artic areas of Alaska and Canada will depend primarily upon pipeline availability and capacity. If commercial production of gas hydrates is determined to be feasible, it is more likely to be a source of fuel used in the Arctic oil and gas field operations.

B. Background on Natural Gas Hydrates

Gas hydrates are metastable solid compounds of one or more gases, such as methane or CO_2, and liquid, such as fresh water or seawater. They can be described as ice crystals with trapped natural gas. The properties of gas hydrates depend upon pressure, temperature, and the composition of the gas and liquids. Naturally occurring gas (primarily methane) hydrates are found in nature under specific conditions of pressure (roughly 200 to 2000 psi), temperature (-10^o to +10^o C), and in areas that are gas prone. Favorable conditions for gas hydrates to occur are normally found in the arctic and in deep water, as illustrated in Figure S5-8.

Figure S5-9 illustrates areas where naturally occurring gas hydrates are known to exist in the world, while Figure S5-10 shows locations where gas hydrates are known to occur in the arctic.

Fully saturated natural gas (methane) hydrates contain approximately 160 cubic feet of gas at standard conditions per cubic foot of in-place hydrate. Natural gas hydrates that form in wells, pipelines, and gas processing facilities can be safety hazards and may reduce natural gas production to zero until the hydrate plugs are removed. Natural gas hydrates can also cause problems if wells have to be drilled through them to reach deeper conventional deposits of oil and gas. Seafloor stability in areas prone to natural gas hydrate deposits is also a safety issue when it comes to drilling, producing, setting of platforms, and the laying of pipelines in deep water.

That said, Earth's vast and widely distributed deposits of natural gas hydrates could become a significant source of energy later in the 21st Century. Table S5-8 (compiled by Collett) shows estimates of hydrated gas-in-place in various areas as developed by several authors. Collett estimates that there are over 300,000 TCF of gas-in-place in U.S. natural gas hydrate deposits, including both the Alaskan North Slope and deepwater areas off both Alaska and the U.S. mainland.

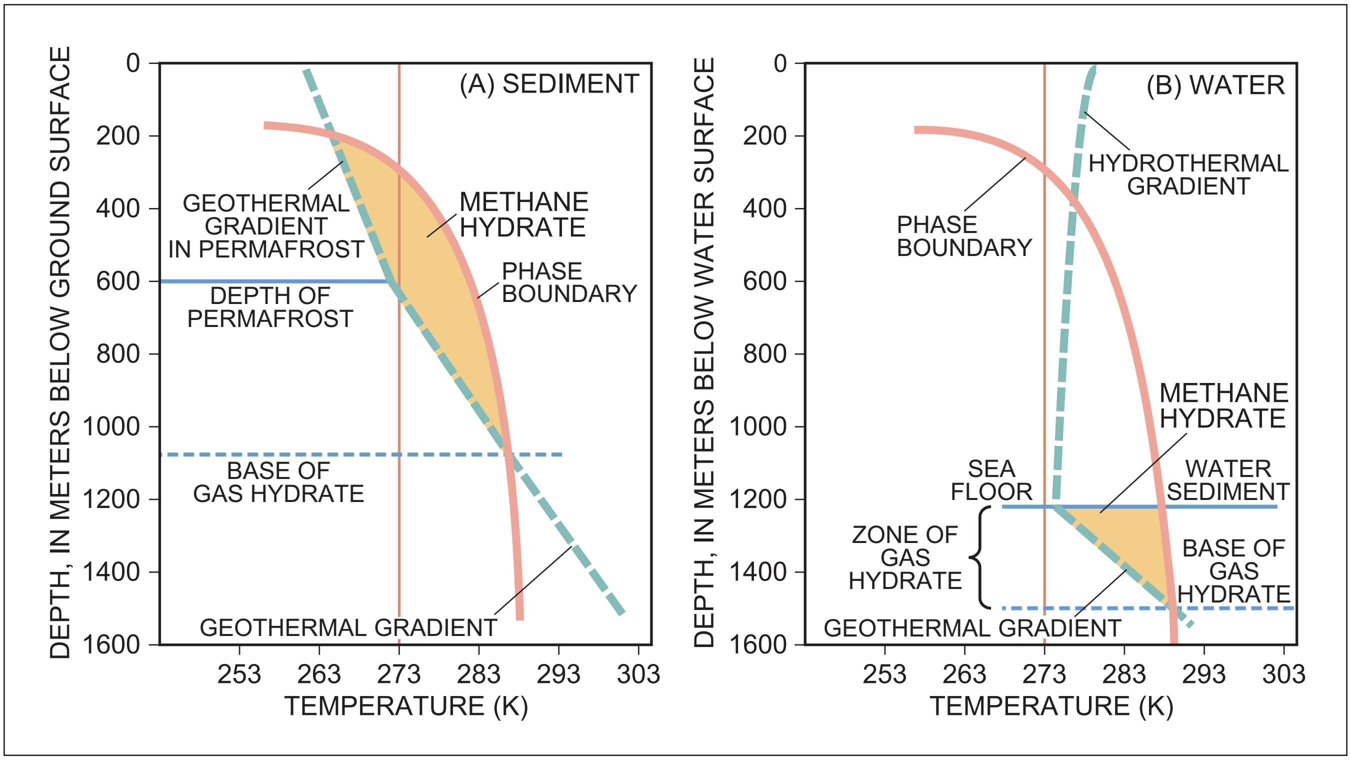


Figure S5-8. Conditions for Hydrate Occurrence

Figure S5-9. Locations of Known and Inferred Gas Hydrate Occurrences in Oceanic Sediment of Outer Continental Margins, and Permafrost Regions

Figure S5-10. Arctic Basins – Areas of Known or Inferred Gas Hydrates

He estimates that the North Slope of Alaska contains as much as 590 TCF of hydrated gas-in-place. To put these estimates into perspective, current U.S. proved gas reserves are about 160 TCF.

C. Workshop Assessment of Gas Hydrates

Given the extremely large estimated volumes of hydrated gas-in-place, it's no wonder that the energy industry and many governments around the world have become much more interested in natural gas hydrates in the past few years. However, there is little evidence that the natural gas industry as yet understands the deposition of natural gas hydrates, or that it fully understands how to characterize the deposits. A number of field research projects in Canada, Alaska, Japan, India, and the United States are beginning to work on the technologies needed to recognize, image, and characterize natural gas hydrate deposits in both the Arctic and deep water environments. Three key questions that must be answered in the near future by

Location	Volume (Trillion Cubic Feet)	Source
United States	317,700	Collett 1995
India	4,307	ONGC 1997
Blake Ridge, USA	635	Dillon et al. 1993
Blake Ridge	2,471	Dickens et al. 1997*
Blake Ridge	2,824	Holbrook et al. 1996*
Blake Ridge	2,012	Collett 2000*
Blake Ridge	1,331	Collett 2000
Nankai Trough, Japan	1,765	MITI/JNOC 1998
Andaman Sea, India	4,307	ONGC
North Slope, Alaska	590	Collett 1997
Prudhoe Bay, Alaska	42	Collett 1997
Cirque-Tar	60	Collett 1999
Mackenzie Delta, Canada	6.6	Collett 1999

*Includes associated free gas.

Table S5-8. National/Regional Estimates of the Amount of Gas within Hydrates these and subsequent research efforts were also addressed by the workshop participants based on presently available knowledge. The three questions are as follows:

1. **Can the industry safely and economically produce gas from natural gas hydrate deposits?**

   During the workshop, a great deal of discussion took place to address this question. Most agreed that it is feasible that gas hydrates could be commercially produced, but there remains a significant number of technical and operational challenges that will need to be overcome before commercial gas from hydrates are realized. There exists a global effort to conduct research in trying to understand gas hydrates and develop methods to eventually produce gas in commercial quantities from them. Japan, India, Canada, and the United States are investing considerably in joint research programs that are addressing gas hydrates as both a bio-hazard and a potential energy source. It is expected that pilot projects in the arctic areas and deepwater offshore areas will begin to emerge over the next several years that will help gain enough understanding that will lead to eventual commercial projects.

2. **When might production of gas from natural gas hydrate deposits begin?**

   The workshop participants decided to use a statistical approach, applied separately to the arctic and deepwater environments, in determining if and when gas production from North American natural gas hydrate deposits might begin and how much gas might be produced.

   A pipeline to move gas southward from the Arctic region of Canada will not be completed until 2009 at the earliest, and 2014 from Alaska's North Slope region. Assuming that the pipelines would be packed with gas produced from conventional reservoirs during the early years of its operation, it is highly unlikely that it could take any gas from unconventional resources such as natural gas hydrates until capacity is available, 2015 at the earliest.

   It is estimated that there would be only a 10% chance that gas production from hydrate deposits would occur beginning in the year 2015. The experts felt that there is a 30% chance production would begin by the year 2020, and a 50% chance that production would begin by the year 2025.

3. **What production volumes would be expected?**

   The experts created three potential production profiles. Profile A is one where production ramps up quickly in time, then begins to flatten. The workshop participants felt this profile was the least likely to occur. Profile C is the situation where gas production from gas hydrate deposits starts slowly but increases with time as more wells are drilled and the industry moves up the learning curve. This is a profile that was observed in the development of coal bed methane. The group felt Curve C was the most likely outcome. Curve B is for constant production increase and it is presented as the mid-case situation.

   In Table S5-9, the probabilities that a certain production profile (A, B, or C) will occur on the basis of when production begins are shown. For example, it is believed that if gas production does begin in 2015,

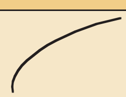
Production Profile	First Production 2015 10% Prob.	First Production 2020 30% Prob.	First Production 2025 >50% Prob.
A 	1% Prob.	1% Prob.	5% Prob.
B 	5% Prob.	10% Prob.	30% Prob.
C 	90% Prob.	80% Prob.	70% Prob.

Table S5-9. Probabilities of First Production and Production Profiles of Natural Gas Hydrates in North America there is a 1% chance it will look like Curve A, and a 90% chance it will look like Curve C. If production begins in year 2025, there is a 5% chance it will look like Curve A, and a 70% chance it will look like Curve C.

Similar to addressing production startup and profile, the session participants had no model to work from to estimate production volumes. They did note, however, that production of gas from coal bed methane reservoirs in the United States went from essentially zero to 1 TCF/year in approximately 10 years. Thus, the decision was made to test the probabilities of 0.5, 1.0, and 2.0 TCF/year as reasonable estimates of the volume of gas that could be produced from hydrate deposits by the 10th year of production.

It was estimated that there was a 90% chance that once gas production began from gas hydrate deposits, it would reach a production level of at least 0.5 TCF/year by year 10. Accordingly, it was estimated that there was a 50% chance it would reach 1 TCF/year in 10 years, and a 10% chance it could reach 2 TCF/year in 10 years.

D. Recommendation to NPC on Natural Gas Hydrate Volumes

After combining all of the insights of probabilities and the speculative nature of when gas production might begin and how much gas might be produced, the workshop participants decided to recommend that the NPC not include any gas production from gas hydrate deposits in its supply forecast through 2025. However, they also recommended that the information and judgment of the experts from the special session be included in the NPC report for future reference.

E. Technology Development for Natural Gas Hydrates

The special session on natural gas hydrates also investigated the several technologies that would be required to develop and produce natural gas from hydrates. The results from this investigation are summarized in Table S5-10.

During the time period of the NPC study, natural gas hydrate research and development can be best summarized in the following time frames:

2003-2010 Public money from government agencies such as the DOE or JIPs made up of both government and industry partners will continue doing the research and technology development.

2010-2015 Some technologies will be developed and field tested in "sweet spots," which are the formations that are deemed easiest to develop and produce.

2015-2020 The technology should become commercial and the resource will be developed by private industry, assuming that pipelines or other means are available to sell the gas or energy developed from the gas.

2020-2025 Slow growth should begin to occur in gas production from gas hydrate deposits.

VIII. Synthetic Gas/Coal Gasification

Synthetic gas or syngas, a mixture of hydrogen and carbon monoxide, was known as "town gas" and was used in many domestic and commercial applications. It was largely displaced after the E&P industry developed low-cost natural gas supplies last century. Current equipment, systems, and infrastructure are now designed for natural gas, with which syngas cannot be blended in existing infrastructure. However it can displace natural gas where an entire system is converted or designed to use syngas.

Historically syngas was normally generated from coal, but current technology allows almost any hydrocarbon to be gasified. Gasification produces clean syngas and leaves contaminants concentrated in an easily handled slag. It is therefore often used to convert low value, impure hydrocarbons such as refinery bottoms, coal, and petroleum coke into a useful product in an environmentally sound way.

The major syngas uses are as fuel, for instance in boilers or gas turbines, to generate hydrogen and as feedstock to make chemicals. As a fuel it can normally be blended with natural gas. The primary current and anticipated applications for gasification in the United States are power generation, hydrogen production, feedstock for chemical manufacturing, and steam generation.

A. Power Generation

Coal gasification produces syngas to fuel gas turbine, cycle powerplants and competes with conventional

Technology Area	Technology Needs
Reservoir assessment technologies	• Seismic and subsurface imaging technologies that will accurately locate producible hydrates • Formation evaluation technologies to assess hydrates in the formation • Unique well testing technologies to test in-situ production of gas from hydrates • Reservoir modeling technologies to accurately simulate hydrate performance • Data management and exchange systems to share results among various parties researching gas hydrates
Drilling and completion technologies	• Small scale, low-cost drilling techniques • Drilling fluids that will be compatible with hydrate zones • Effective bottom hole insulation technologies to maintain proper temperature environment
Production methods	• Understanding how hydrates behave during depletion and what is the most effective way to release gas from hydrates; thermal, chemical, or depressurization? • Low-cost chemical inhibitors to prevent hydrates from reforming during production • Understanding how overburden and formation integrity is maintained, thought to be the most significant risk associated with producing hydrates
Processing and transportation	• Cost-effective water separation and handling technologies • Insulation and flow assurance technologies to prevent hydrates from reforming during gathering and processing

Table S5-10. Technologies Needed to Develop and Produce Natural Gas from Hydrates

coal-fired powerplants. The Polk facility in Florida is the only commercial gasifier operating to produce power in the United States, but this sector has the potential to grow under certain conditions. In comparison to conventional coal plants, gasification is:

- More costly to build and operate, although the gap is narrow and closing
- Slightly less reliable, i.e., it has slightly more power outages
- More efficient with a better heat rate
- Relatively unproven so faces industry resistance to widespread deployment
- More environmentally friendly as it produces less SO_x, NO_x, and mercury.

The use of gasification to produce power is captured in overall forecasts for coal-fired power generation during the later time frame of the forecast.

B. Hydrogen Production

Hydrogen is used widely in refining of heavy crude oils and to remove sulfur when making clean gasoline and diesel. Currently most hydrogen is produced from Steam Methane Reformers (SMRs), which use natural gas in a very energy-intensive process. There are a very few gasifiers, which also use natural gas, and some hydrogen comes as a byproduct from chemical manufacture.

Hydrogen demand in the United States is predicted to grow significantly as more heavy crude is refined and clean fuel regulations take effect. In the longer term, demand will increase as the hydrogen economy develops. On the supply side, older SMRs must be replaced in the foreseeable future. Hydrogen supplies were traditionally integrated into refineries but the current trend is to have them provided "over the fence" by third-party industrial gas companies. This may make it more difficult to build gasifiers using refinery wastes such as bottoms or petroleum coke.

This is an opportunity for gasification, which compared to SMRs is:

- More costly to build
- Perceived to be less reliable by industry
- Relatively unproven with non-natural gas feed so industry reluctant to deploy
- Able to use other, lower value hydrocarbon feeds than natural gas
- Less energy intensive so lower operating cost
- More environmentally sound.

C. Feedstock for Chemical Manufacture

Although relatively common in China, gasification for chemical feedstock is only used in a few U.S. locations, notably Eastman Chemical's facility in Tennessee. It is good use for gasification and likely to be used in the future, but it is probably not a large enough sector to significantly impact the U.S. gas balance.

D. Steam Generation

Refineries and some manufacturers use large volumes of steam, which gasification produces. If there is a suitable host, an integrated gasification and combined cycle facility is a very economic option. Lake Charles, which CVX is currently considering, is probably the largest and best suited example and would displace approximately 180 mmscf/d of natural gas. There are probably less than a dozen U.S. locations where this could apply so total impact on the U.S. gas balance is likely to be less than 2 billion cubic feet per day.

E. Other Possible Applications

Syngas can be feedstock to Fischer-Troppe reactors to make clean fuel, and gasification has been used to destroy waste hydrocarbons with the syngas being largely a byproduct. Neither of these, or other possible niche applications, will be a significant impact.

F. Impact of Natural Gas Price

At high gas prices coal gasification begins to look economically attractive and may have some application as an alternative fuel source in future powerplants built in North America. At lower gas prices it is almost certainly uneconomic although it may suit niche applications (e.g., where environmental issues are important) and geographic areas where suitable feedstock is cheap (e.g., in coal mining areas or near refineries producing coke or bottoms) and/or natural gas is costly.

IX. Summary Issues and Challenges

Several issues and challenges will face the North American petroleum industry and governments as they pursue research, development, and application of new technologies to enhance the supply of natural gas.

Although many of the North American producing basins are maturing, significant technically recoverable resources still remain. However, their declining reserves and economics will make it difficult to justify major investments in new technology. Independent companies, which will play an increasing role in these mature basins, will have to increase collaboration with the service industry to fund and support the required technology development.

Industry must also speed up the acceptance and utilization of new technology. Having many producers spread across North America creates a challenge to efficient and effective technology collaboration due to competitive pressures. The shift toward more collaborative research increases the difficulty of testing and deploying new technologies. Professional societies, trade associations, academic and government research institutions, along with the industry will need to increase efforts to communicate and work together to deploy new applications.

Another challenge will be to effectively transfer the knowledge and replace the experience of the existing professional workforce to the new generation entering the industry and research institutions. Otherwise, the risk of "reinventing the wheel" will loom over the industry.

With the expected tight supplies of natural gas, potentially higher prices, and ever increasing technical challenges, the petroleum industry, research institutions, and governments need to quickly put in place strategic plans to respond to these challenges.

CHAPTER 6

ACCESS ISSUES

I. Report Narrative

This report demonstrates the clear need to augment natural gas supply in the lower-48 area of the United States. Access to lands, both public and private, and submerged lands underlying the oceans of the United States, in order to conduct oil and gas exploration and development operations has become an increasingly significant issue in the United States in recent years. Efforts by certain advocacy groups to stop oil and gas exploration and production activities have convinced the federal government to set more and more federal lands and submerged lands off-limits to development either through legislation, executive order, regulation, or administrative decisions. Federal and state regulatory requirements have also led to steadily increasing costs and time delays, which make it increasingly difficult to economically produce natural gas from areas that are nominally open to leasing.

The trend towards increased access restrictions and land set-asides has been especially true in the interior western states and in the U.S. offshore areas, where significant portions of the remaining domestic natural gas resources lie. The Access/Environmental Subgroup dedicated a great deal of its time and resources to studying the access-related issues in these producing regions, which have been the focus of so much attention and controversy in recent years.

The 2003 study estimates that 238 trillion cubic feet (TCF) of natural gas resources underlie the Rocky Mountain area, or 24% of the total remaining resource in the U.S. lower-48. Of this total resource, the Reactive Path scenario of the 2003 study estimates that 69 TCF, or 29% of the resource base in the Rocky Mountain area, is currently off-limits to exploration and development, either due to statutory leasing withdrawals or to the cumulative effects of conditions of approval associated with exploration and development activities. In addition, the 2003 study estimates that access-related statutory/regulatory/administrative requirements add very significant costs and delays to wells drilled in this area. Obviously, a continuation of the trend towards placing an increasing percentage of this resource off-limits to development could further impact both the deliverability and price of natural gas in the future.

The other major area of focus for the Access/Environmental Subgroup was the submerged lands underlying the oceans of the United States. As a result of various Executive Orders, virtually the entire Atlantic and Pacific coasts of the U.S. lower-48 are not available for oil and gas leasing through 2012. Significant portions of the Gulf of Mexico and offshore Alaska are also inaccessible to leasing. Since the release of the 1999 NPC study, this trend towards restricted access to development has also become manifest in the Eastern Gulf of Mexico. In 2001, the Department of the Interior, encouraged by the State of Florida, made a decision not to follow through with the entirety of the area of its planned OCS Lease Sale 181. Instead, it reduced the boundaries that had originally been set for the sale by more than three-fourths including all of the acreage offshore Florida, thus setting another potentially significant resource off-limits to exploration and development. Also since the release of the 1999 NPC study, new issues have arisen in the offshore, as described later in this chapter, which could significantly impact industry's ability to continue to develop the large natural gas reserves that underlie these submerged lands.

The 2003 study estimates that 354 TCF of natural gas resources underlie the submerged lands of the oceans of the U.S. lower-48, or 36% of the total remaining resource in the U.S. lower-48. Of this total resource, the 2003 study estimates that 79 TCF, or 22%, is currently off-limits to exploration and development due mainly to existing moratoria. These OCS resource estimates are based on limited and aged data due to Congressional restrictions forbidding the Minerals Management Service to gather more current information. If more current data were available, a significant upward range could exist around this potential resource. As with the Rocky Mountain area, a continuation of the trend towards placing an increasing percentage of this resource off-limits to development could further impact both the deliverability and price of natural gas in the future.

Study areas of the United States, along with the estimated undiscovered resource underlying each of them, are detailed in Figure S6-1.

The 2003 study also examined access issues in Canada, and, referencing a recently published study on potential Canadian gas supply conducted by the Canadian Energy Research Institute, determined the percentages of the various producing basins that are currently off-limits to leasing. These percentages were used in the long-range modeling process. While other access and environmental issues do exist in Canada, in general, they do not deny producers the ability to conduct exploration and development activities, and a detailed analysis of their impacts would not likely have a material impact on the outcome of the 2003 NPC study results.

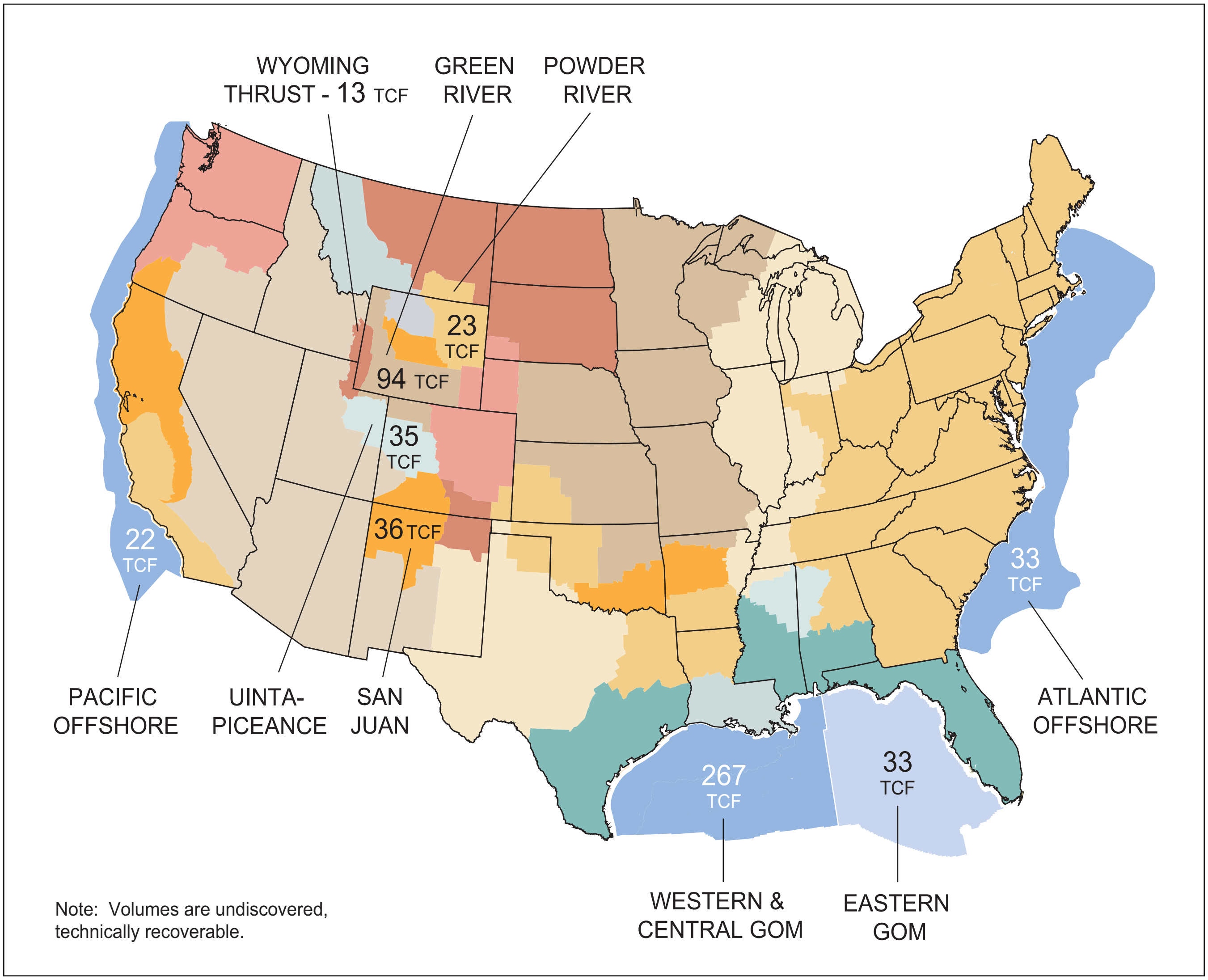


Figure S6-1. Estimated Undiscovered Resource by NPC Access Study Area

A. Rocky Mountain Area

Participants in the 2003 study were fortunate to have three previously published Rocky Mountain access-related reports to use as reference points:

- The 1999 NPC Study
- The 2001 Greater Green River Basin Study conducted by the Department of Energy (Federal Lands Natural Gas Assessment – Southern Wyoming and Northwestern Colorado)
- The 2002 EPCA Study conducted by the Departments of Energy and Interior (Scientific Inventory of Onshore Federal Lands' Oil and Gas Resources and Reserves).

The following is a brief description of each study:

- **1999 NPC Study.** The 1999 NPC natural gas study evaluated Rocky Mountain access restrictions and included an assessment of no-access, high cost, and standard lease terms resources in the entire Rocky Mountain region. The access study had the objective of evaluating access to all undiscovered resources (not just federal resources), but was based upon analysis of federal lease stipulations in several Rocky Mountain basins, and therefore did not assess the additional cumulative impact of conditions of approval that are evaluated in the current NPC study.
- **2001 Greater Green River Basin Study.** In 2001, the Department of Energy published a study of access to natural gas underlying federal lands in the Green River Basin. The study, titled "Federal Lands Natural Gas Assessment – Southern Wyoming and Northwestern Colorado," evaluated the impacts of lease stipulations on federal lands in the Green River Basin. The study was carried out by the Department of Energy's Fossil Energy office in coordination with the Bureau of Land Management, and Forest Service.
- **2002 EPCA Study.** The 2002 EPCA study evaluated access to gas resources on federal lands in five Rocky Mountain Basins: the Green River, Powder River, Uinta-Piceance, San Juan-Paradox basins and the Montana Thrust Belt in western Montana. "EPCA" refers to the Energy Policy and Conservation Act Amendments of 2000, which directed the Secretary of the Interior, in consultation with the Secretaries of Agriculture and Energy, to conduct an inventory of oil and natural gas resources beneath federal lands. Only federal lands and gas resources were evaluated, and only the effects of lease stipulations were included, with no attempt to evaluate the cumulative impact of conditions of approval. The study included ten categories of lease stipulations, and quantified the federal resources associated with each category. The three most restrictive categories were classified as "no-leasing," while six categories were classified as high cost, and one category was classified as "standard lease terms."

As seen in Table S6-1, each of these studies examined access and environmental issues in various basins of the Rocky Mountain area, and attempted to quantify their impacts on recoverable natural gas reserves. In addition, each of these three studies limited their examination to the impacts of federal lease stipulations, though the Greater Green River Basin study did look at a few conditions of approval. The intent of this study is to build on these prior works and present a more comprehensive analysis of the impact of access restrictions on Rocky Mountain natural gas production by conducting an analysis of the impacts of conditions of approval.

The term "conditions of approval" (COA) refers to impediments to development that arise during the post-leasing permitting process. These COAs arise from a variety of controlling authorities, but the most significant and wide-ranging tend to be those governed by three federal Acts:

- The National Environmental Policy Act (NEPA)
- The Endangered Species Act (ESA)
- The National Historic Preservation Act (NHPA).

As shown in Figure S6-2, these COAs constitute a very significant piece of the access picture in the Rocky Mountain area, and in many instances actually become more of an impediment to exploration and development than the lease stipulations. The participants in the 2003 study concluded that the three prior reports described in Table S6-1 had done an excellent job of quantifying the impacts of federal lease stipulations, and that it would be important for the 2003 study to advance the body of knowledge by examining the impacts arising from COAs on federal and non-federal lands.

	1999 NPC Study	2001 Greater Green River Basin Study	2002 EPCA Study
Areas of Analysis	Federal lands in five major basins Lease stipulations NPC resource base, undiscovered technically recoverable	Federal lands within Green River Basin Lease stipulations Limited Conditions of Approval 1995 USGS resource base, technically recoverable	Federal lands in six major basins Lease stipulations Proved reserves + undiscovered technically recoverable
Percentage of Federal Natural Gas Resource			
Off-Limits	9	30	12
Available for Leasing with Restrictions	32	38	25
Available for Leasing with Standard Lease Terms	59	32	63

Table S6-1. Rocky Mountain Basin Access Studies

1. Methodology

As the first step in quantifying the impacts arising from COAs, it was necessary to develop maps of the major Rockies natural gas basins, with special emphasis on potential habitats for listed threatened, endangered and candidate species. To perform this task, the NPC contracted with Hayden-Wing and Associates, an environmental consulting firm located in Laramie, Wyoming. Hayden-Wing is widely recognized for its expertise in the performance of wildlife surveys, environmental impact statements, wetlands evaluations and developmental permitting.

The Hayden-Wing work focused on four major natural gas-producing basins in the Rocky Mountain area: The Green River Basin, the Uinta-Piceance Basin, the Powder River Basin, and the San Juan Basin. These four basins together contain roughly 79% of the total natural gas resource base in the Rocky Mountain area. Examples of the maps prepared by Hayden-Wing are provided in a CD-ROM that is available with this report.

All told, Hayden-Wing mapped the habitats and migratory ranges for 28 threatened and endangered species in the Green River Basin, 41 species in the Uinta-Piceance Basin, 19 species in the Powder River Basin, and 25 species in the San Juan Basin. In addition to the preparation of these maps, Hayden-Wing also quantified the percentage of the land areas in these basins that are covered by each habitat and migratory range, as well as the frequency of occurrence of events requiring specific survey or mitigation actions on the part of oil and gas operators, such as active raptor nests, active Sage Grouse leks, big game birthing habitats, and other similar events.

Next, the NPC assembled a team of industry experts (hereinafter referred to as the Rockies Expert Team) who have in-depth experience with access-related issues in the Rockies, to work in conjunction with Hayden-Wing to quantify the costs and time delays associated with complying with each of these conditions of approval. The team also determined whether each COA applied to state and fee lands, in addition to federal lands.

In addition, the Rockies Expert Team developed cost and time delay data associated with complying with COAs related to archaeological activities governed by the National Historic Preservation Act and environmental analyses (EA) and environmental impact statements (EIS) required by the National Environmental

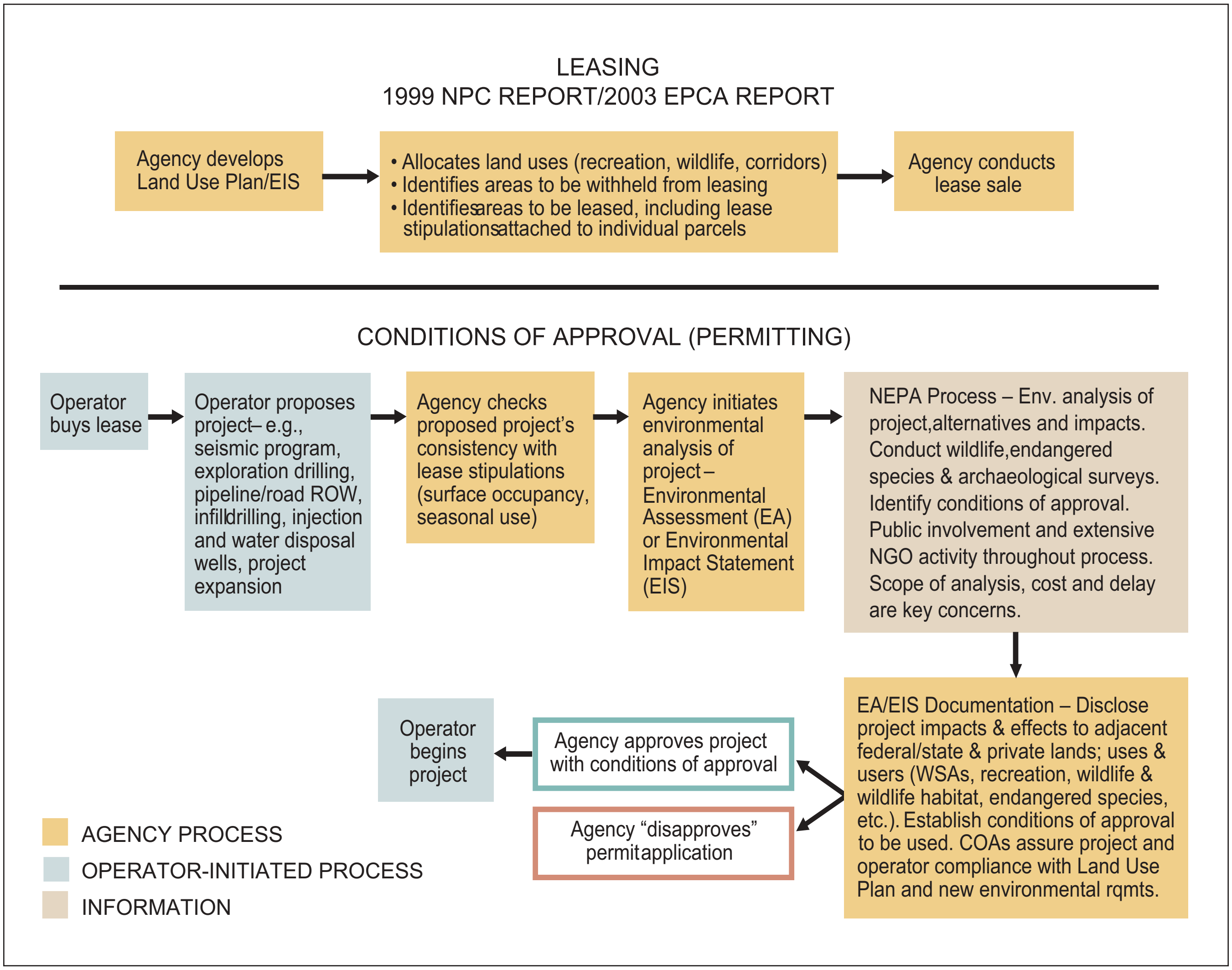


Figure S6-2. Comparison of Lease Stipulations and Conditions of Approval

Policy Act. These data were developed by analyzing costs and delays incurred on actual projects conducted in these basins.

Once all the data had been compiled, they were input into a statistical analysis matrix created by Energy and Environmental Analysis, Inc. (EEA) specifically for this project. The matrix analyzed the cumulative effect of the COAs in each basin for 1,000 hypothetical wells. Separate model runs were made to determine the impacts on federal lands, state lands and fee lands in each basin. By taking a weighted average based on the cumulative acreage of each of the three land types, the team was able to determine the average costs and timing delays per well in each basin associated with COAs, as well as the gross percentage of land in the basin that is effectively off-limits to development as a result of the cumulative effects of COAs. This process is outlined in Figure S6-3.

Efforts were next made to normalize the areas of acreage effectively off-limits due to COAs to the play areas within each basin, and to subtract the percentage of lands in each basin already determined by the 2003 EPCA study to be off-limits due to leasing restrictions. This allowed the team to determine the net estimated basin-wide percentage of natural gas resource that is effectively off-limits due to COAs for each of the four major basins.

These findings are summarized in Table S6-2. For purposes of this report, any acreage that was rendered unavailable for surface occupancy for a minimum of 9 months per year due to the cumulative effect of COAs is considered to be "Effectively Off-Limits to Development."

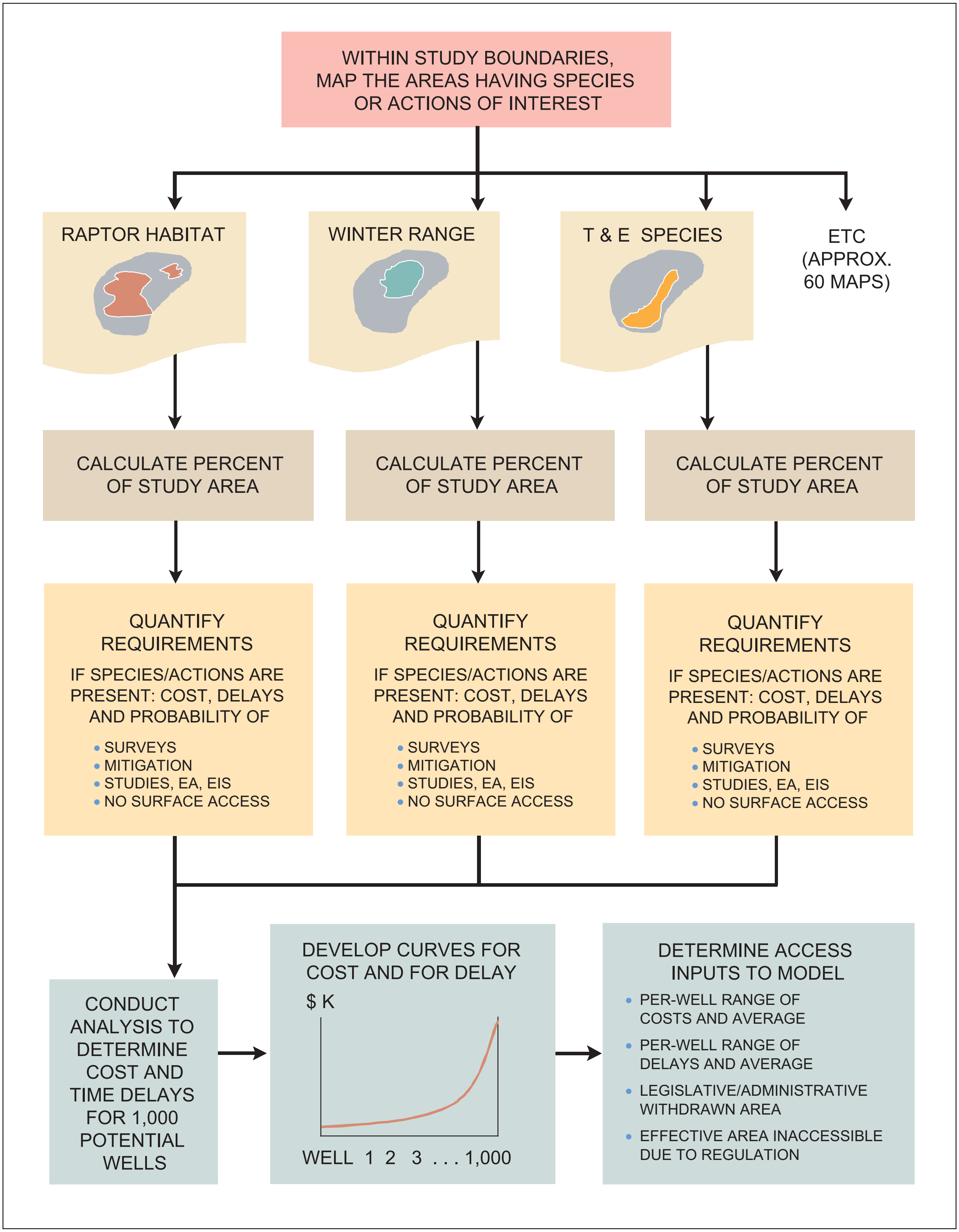


Figure S6-3. Access Quantification Process

	Green River	Uinta-Piceance	Powder River	San Juan
Resources Off-Limits				
Federal Statutory/Administrative	8.7%	4.1%	4.6%	2.3%
No Leasing				
Prohibitive Conditions of Approval				
12 Months Off-Limits	24.5%	15.2%	5.7%	6.2%
9-11 Months Off-Limits	6.9%	1.8%	20.3%	0.1%
Total Restricted Percentage	40.1%	21.1%	30.6%	8.6%
Average Added Costs per Well Due to Conditions of Approval ($k)				
Federal/State Exploratory	240-250	146-152	103-108	63-68
Federal/State Development	90-95	104-108	57-61	53-57
Weighted Average	103	107	62	55
Fee Exploratory	48-52	54-56	15-20	30-34
Fee Development	54-58	68-70	17-21	30-35
Weighted Average	56	69	19	33
Average Time Delay (Months)				
Federal/State Exploratory	12-14	9-11	2-4	5-7
Federal/State Development	20-22	7-9	13-15	6-8
Fee Exploratory	2	2	6	1
Fee Development	2	2	2	1

Note: Percentages refer to conventional new field and unconventional resources only. Growth of old conventional fields is not included.

Table S6-2. Findings – Rockies Access Restrictions

2. Reactive Path Scenario Modeling Assumptions and Results

The findings summarized in Table S6-2 were used as the Onshore modeling assumptions for the Reactive Path scenario of this study. In addition to the four major producing basins discussed above, the Rockies Expert Team examined access restrictions in the area defined by this study as the Wyoming Thrust Belt. This examination was conducted by comparing land use planning maps of this region to the play areas developed by the NPC Resource Team. The Expert Team also applied its knowledge of administrative leasing policies currently being employed in the area by the governing agencies. Using this information, the Expert Team determined that roughly 80% of the resource underlying the Wyoming Thrust Belt area is currently withdrawn from leasing due to administrative decisions. This factor was used in the modeling assumptions for the Reactive Path scenario.

The Rockies Expert team also evaluated access to the Montana Thrust Belt province, which was included in the EPCA study. The EPCA study concluded that approximately 91% of the federal resource in this province is off-limits to industry. The current study estimates that more than 80% of the total resource base is off-limits in this province.

Assessments of resource access were also made for the remaining six Rocky Mountain basins. These are the Williston, Big Horn, Wind River, Denver, Raton, and Paradox. Land administration and access information obtained in the 1999 NPC study was the primary source of access information for these basins. Since the 1999 NPC study did not include the full range of conditions of approval evaluated in the current study, the 1999 NPC study results were adjusted by the Rockies Expert Team to arrive at assumed access percentages for these basins for modeling purposes.

As a result of the analysis discussed above, the NPC has determined the level of Rockies Access Restrictions for the key Rockies basins as summarized in Table S6-3.

The above restriction parameters were used in the Reactive Path scenario. As noted above, 29% of the resource base in the Rockies is determined to be off-limits. This is a substantial increase over the same result in the 1999 NPC study (9%) and this increase is almost all attributed to COAs.

Finally, as shown in Figure S6-4, a limitation on the rate of increase in the number of permits issued by the governing agencies was developed and included in the modeling process. These agencies do not enjoy unlimited resources to deploy to the permitting function whenever a new play develops in a given area and creates a sudden demand for increased permitting. This has most recently been manifest in the coal seam play in Powder River Basin, where the Bureau of Land Management was unable to meet the initial large demand for new permitting until Congress appropriated additional funds specifically dedicated to that purpose.

After vetting the idea within the Rockies Expert Team and discussions with personnel from the BLM, and examining basin-by-basin outputs from the initial modeling runs, the Expert Team developed a set of limitations to the yearly rate of increase in permitting based on the number of successful wells drilled in a given basin in the previous year, as follows:

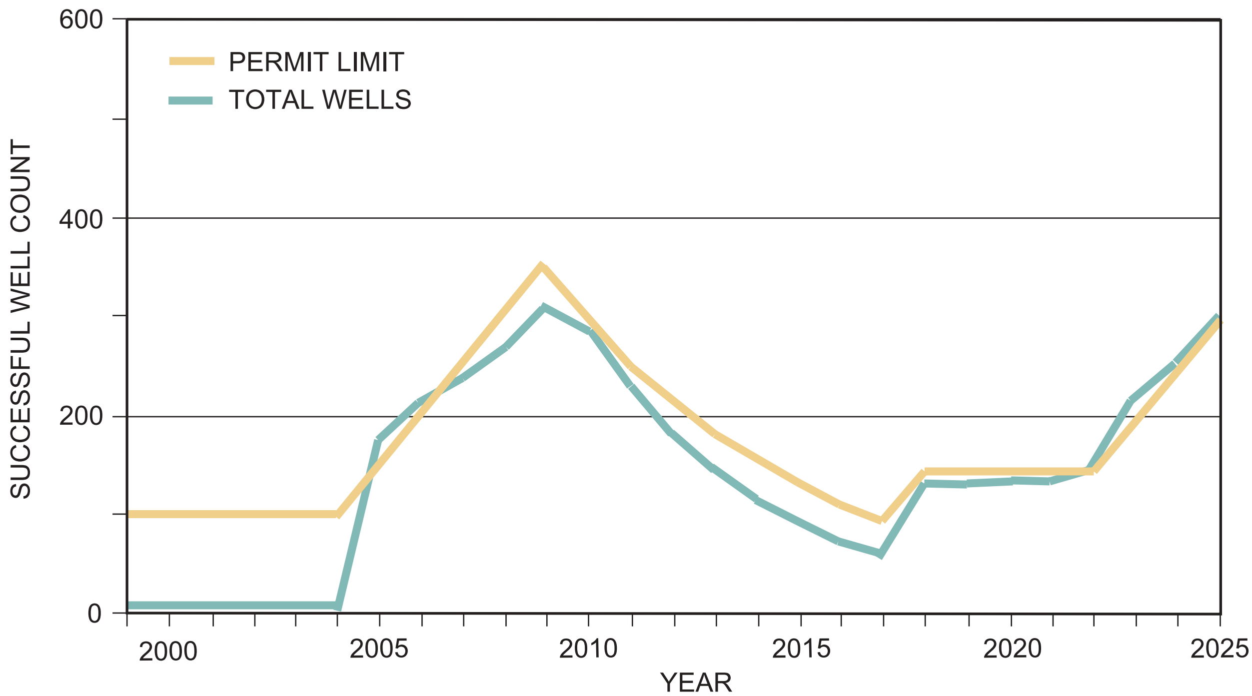
- If the drilling program is to result in 100 or fewer successful wells, it is assumed that the number of permits requested would be low and could be handled by the agencies without additional funding or personnel. Thus, no limitation was set on these basin areas.

- If the number of wells drilled in the previous year was greater than 100 but less than 300, it is assumed that (1) the permitting caseload is fairly heavy, and

	Standard Lease Terms	High Cost	No Access	Total
Williston, Northern Great Plains	10,634	1,930	553	13,117
Uinta-Piceance Basin	**14,349**	**13,735**	**6,492**	**34,575**
Powder River Basin	**15,369**	**610**	**6,627**	**22,607**
Big Horn Basin	646	232	18	896
Wind River Basin	2,838	1,005	205	4,048
Southwestern Wyoming (Green River Basin)	**35,077**	**24,336**	**34,880**	**94,293**
Denver Basin, Park Basins, Las Animas Arch	4,700	945	37	5,682
Raton Basin-Sierra Grande Uplift	1,574	295	98	1,968
San Juan	**22,575**	**10,353**	**2,576**	**35,504**
Montana Thrust Belt and SW Montana	1,354	19	6,955	8,328
Wyoming Thrust Belt	3,237	557	9,606	13,401
Great Basin and Paradox	868	1,755	1,086	3,709
Rockies Volumes	113,222	55,772	69,134	238,128
Rockies Percentages	47.5%	23.4%	29.0%	100.0%

Note: Includes growth in conventional old fields, characterized as 60% Standard Lease Terms and 40% High Cost.

Table S6-3. Technically Recoverable Resource – Current Technology, Reactive Path Scenario (Billion Cubic Feet)



Note: Assumptions regarding permitting pace to result in a targeted number of successful completions per year are as follows: < 100 wells – no constraints; 100 to 300 wells – can increase 50 per year; > 300 wells – can increase 15% per year.

Figure S6-4. Permitting Pace – Rockies, Example Basin

(2) that the agencies would have to perform work-shifting or add new personnel to handle a sudden increase in permitting requests. In these basins, a limitation of no more than 50 new permits above the prior year's level was set.

- If the number of wells drilled in the previous year was greater than 300, it is assumed that the permitting caseload is very heavy and that new personnel and funding would be required for the governing agencies to handle rapid increases in permitting requests. In these basins, the rate of annual increase is limited to 15% above the prior year's level.

3. Key Rockies Issues

Detailed analyses on a variety of the key access/environmental issues faced by producers in the Rocky Mountain area may be found in a CD-ROM that is available with this report. Below are brief summaries of a few of the issues that produce the most significant, wide-ranging impacts throughout the area.

a. Endangered Species Act

Nominations for additions to the list of species protected under the Endangered Species Act (ESA) pose challenges for the governing agencies and lessees. To be clear, the problem does not arise from the obligation to protect listed threatened or endangered species. Rather, it is the fact that *anyone* can file a petition to list, which has led to species being proposed for the express purpose of employing the Endangered Species Act as a land management tool.

All protective measures authorized by ESA may be applied to the proposed species and their habitats, and once on the endangered species list, a species is rarely taken off. Agencies have 90 days to find whether substantial information exists to indicate the proposed listing may be warranted. Due to the short timeframe and the usual lack of specific species information, agencies most often treat *proposed* and *candidate* species as if they are listed, without fulfilling the ESA's specific requirements for species status, distribution, and habitat information. Environmental analyses for proposed projects become more complex and costly and are prone to additional delay given the sheer number of proposed and candidate species. It is important to note that ESA restrictions and remediation efforts required to comply with them apply to state and private fee lands as well as federal lands. The open-ended nomination process has several other significant impacts:

- Inordinate uncertainty and risk is created for lessees, states, private landowners, and land management agencies.

- Land use planning and environmental analysis cost, complexity, and delay are increased.

- The importance of distinguishing species that qualify for protection under the Endangered Species Act from those that do not is lost, resulting in needless effort and waste of federal and public resources.

In addition, states maintain extensive lists of sensitive species (e.g., Uinta-Piceance Basin alone has 272 species) that are identified by regulatory agencies to be at risk of becoming endangered, extinct, or warranting further research. Projects are subject to future regulation, access restrictions, and mitigation at the discretion of state regulatory agencies.

b. National Historic Preservation Act

Enacted in 1966, this act authorized the federal government to take actions necessary to determine the impacts of construction projects "on any district, site, building, structure, or object that is included in or eligible for inclusion in the National Register."

Prior to project construction or seismic activities, a Class III archaeological inventory (defined as a record of all cultural properties, which can be identified from surface indications, for a specific area) of the lands involved must be completed to determine what impacts the undertaking will have on archaeological or historical resources. The Act affects federal lands and private and state lands where split estate ownership is present. Experienced delays range from 30 days to several years, based on the results of the findings from the inventory. Costs associated with the basic Class III inventory and report with no findings range from approximately one thousand to hundreds of thousands of dollars for research designs, mitigation reports, and testing of archaeological and historic sites that are encountered during construction.

Based upon the results of the Class III inventory, the operator may have several mitigating options, including:

- No further action necessary, construction may commence

- Avoidance of the cultural resource

- Funding by the operator for further studies of the resource to determine the significance of the cultural resource

- Project cancellation due to the significance of the costs of compliance.

c. National Environmental Policy Act

Enacted in 1969, the National Environmental Policy Act is our basic charter for protection of the environment. NEPA is a procedural act that, in conjunction with its implementing regulations, was designed to ensure the federal government considers the environmental consequences of all major federal actions that significantly affect the human environment. NEPA established the environmental review process and created the Council on Environmental Quality (CEQ) within the Executive Office of the President. CEQ developed regulations that require public involvement throughout an extensive environmental analysis process that examines:

- The environmental impact of the proposed action

- Any adverse effects which cannot be avoided

- Alternatives to the proposed action

- Relationships between local short-term uses and maintenance and enhancement of long-term productivity

- Any irreversible and irretrievable commitments of resources that would be involved if the proposal is implemented.

The clear intent and expectations identified in the NEPA statute and CEQ regulations for a compact, clear, and efficient environmental analysis and decision-making process have not been met in practice by the governing agencies. The manner by which land use plans and project permitting documents are developed has led to public uncertainty and distrust about the federal decisions being made. The NEPA process has become complex and cumbersome, and has greatly increased cost, delay, and uncertainty for operators seeking exploration and development access to public lands.

Inadequate staffing and funding at some BLM and Forest Service offices causes the process of completing EISs to become so time-consuming – often taking up to four years to complete – that many producers choose to bear the costs of completing these studies in order to speed up the process. The resulting delays and high costs related to NEPA compliance, coupled with high geologic risk, have caused many potentially viable projects to remain uncompleted.

The practice of cost shifting NEPA compliance costs from agencies to lessees and operators is becoming the norm, and is a major issue for producers. In the past, operators would pay for surveys for cultural resources, threatened and endangered species, or other biological resources on a voluntary basis to expedite project timing. Today, operators are routinely expected to pay for the entire environmental analysis, and preparation of the NEPA document itself, including, in some cases, to contribute to land use plan updates such as the recently completed Powder River Basin Oil and Gas Final Environmental Impact Statement, in order to facilitate leasing, exploration, and development activities.

The manner by which federal agencies implement NEPA stands as the single most significant impediment to recovery of natural gas reserves from onshore areas of the United States. Significant streamlining and adequate funding of NEPA-related processes – both land management planning and the environmental analysis process – is vital to industry's ability to meet future U.S. natural gas demand.

B. Offshore United States

Of the approximately 1.5 billion acres of offshore submerged land under U.S. jurisdiction, only 11% (169 million acres) is currently available for leasing. Approximately half of this acreage is located in the Central and Western areas of the Gulf of Mexico, in which 98% of all leasing and drilling activities in federal waters are conducted. Within the entire Gulf of Mexico, only 54% (86 million acres) is available for leasing and 46% (74 million acres) is closed to leasing.

The NPC assembled a team of industry experts (hereinafter referred to as the OCS Expert Team) who brought with them extensive, practical industry experience in dealing with environmental and regulatory issues that affect petroleum resource development in the OCS. The OCS Expert Team analyzed the effects of existing environmental and access-related restrictions in the offshore United States in terms of time delays and increased costs per well, and ensured these data items were accurately reflected in the EEA model. The team also identified the key issues affecting access to development in the OCS and compiled detailed analyses of them, including the public policy recommendations contained elsewhere in this report, and developed the modeling assumptions for the modeling cases conducted throughout the course of this study.

The single largest restriction to access to natural gas resources in the offshore United States is the Presidential Order issued by former President Bush and extended by former President Clinton. With additional Eastern Gulf of Mexico acreage withdrawn, these access restrictions created moratoria on exploration and development activities throughout virtually all of the Atlantic and Pacific oceans and most of the Eastern Gulf of Mexico through June 30, 2012. In addition, the remainder of the Eastern Gulf of Mexico remains off-limits due to opposition from the state of Florida and the subsequent decision by the Department of Interior to significantly reduce the previously approved Lease Sale 181 area.

The 2003 study estimates that 79 TCF of potential natural gas resource underlies the submerged lands of the oceans of the United States that are off-limits to development. It is quite possible that this is an understated number since resource estimates in these areas are derived from aged information. Through the appropriations process, Congress precludes the Minerals Management Service (MMS) from spending any money to acquire current data to more accurately assess the resource potential that underlies the OCS. Figure S6-5 compares the MMS Gulf of Mexico natural gas resources estimate for 1995 and 2000, and shows the significant increase in the estimated resource that resulted over time from industry exploration and development activities. Resource assessments for the areas currently subject to moratoria would likely increase significantly were MMS allowed to obtain more thorough information and accurate seismic data.

It is important for future energy policy and for the national security to obtain an accurate assessment of the potential natural gas reserves in the OCS moratoria areas. These areas, along with the estimated undiscovered resource underlying each of them, are detailed in Figure S6-1.

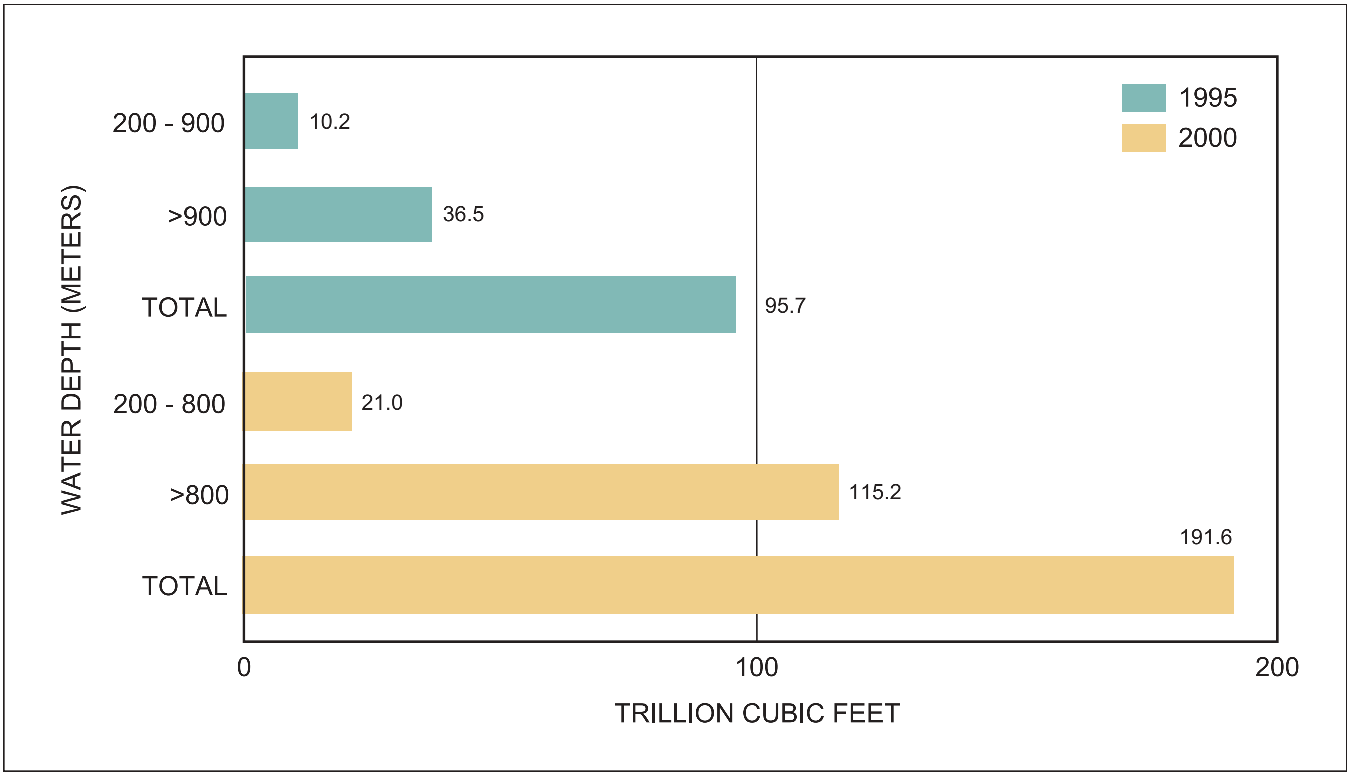


Figure S6-5. MMS Gulf of Mexico Risked Mean Undiscovered Conventionally Recoverable Gas Resources

Despite these limitations on exploration and development, roughly 26% of current domestic daily natural gas supply is produced from land underlying federal waters. It is important to note that most of this resource is produced from land underlying relatively shallow (less than 1000') waters of the Central and Western Gulf of Mexico, a relatively mature area whose production is projected to decline throughout the scope of this study.

1. Reactive Path Scenario Modeling Assumptions

For the purposes of the Reactive Path scenario of this study, the following modeling assumptions were made:

- All Presidential Order moratoria would remain in place through 2025.
- All waters placed off-limits due to administrative decisions of the Department of the Interior would remain in place throughout the scope of the study.
- No additional acreage beyond that covered in the Minerals Management Service's 2002-2007 Five-Year Leasing Program will be offered throughout the scope of the study.

2. Key Issues

In addition to submerged lands that have been off-limits since 1990 due to presidential moratoria, a number of other issues impact the industry's ability to conduct exploration and development activities for available leases in the OCS. These types of restrictions, combined with rapidly declining reserve replacement in the Western and Central Gulf, could dramatically impact 26% of this nation's energy supply. Detailed narratives addressing these issues may be found in the appendix to this report. Below are brief summaries of some of these issues and the laws, processes, and/or institutions associated with them.

a. Coastal Zone Management Act

The Coastal Zone Management Act (CZMA) was passed in 1972 to encourage coastal states to promote "the effective management, beneficial use, protection and development of the coastal zone." The law allows these states to create CZM programs with the approval of the Secretary of Commerce. States with approved programs are able to exercise a wide range of control over the direct and indirect actions of the federal government and its agencies as they relate to the OCS.

Through this provision, some offshore oil and gas activities have been subjected to almost absolute state control, creating serious conflicts between the Commerce Department's administration of the CZMA and MMS's implementation of the Outer Continental Shelf Lands Act. Conflicts have also arisen between states, when one state objects to leasing, exploration, and production activities on the OCS off the shores of other, neighboring coastal states that approve of those activities. As the Coastal Zone Management Act stands today, logical, scientifically based MMS leasing decisions as well as environmentally safe proposed offshore exploration and production projects may be delayed or even abandoned as the result of unsubstantiated, alleged impacts on a single state's coastal zone.

b. Marine Mammals Protection Act/ Endangered Species Act

Recent actions by the National Oceanic and Atmospheric Administration (NOAA) and MMS in the area of marine mammals and endangered species could significantly impact exploration and development operations in the deepwater Gulf of Mexico. NOAA and MMS are examining the issue of noise in the water and its possible effects on mammals located in the Gulf of Mexico. The current focus is on seismic activities and the use of explosives for platform removal.

The natural gas industry supports efforts by both NOAA and MMS to use the best available scientific data to define prudent and effective policies to protect marine mammals and endangered species. However, regulatory changes that are not based on sound science may not be completely warranted or likely will not provide the protection sought and could impede the development of secure domestic resources in the Gulf of Mexico.

The industry agrees with NOAA's finding that oil and gas leasing in the Gulf of Mexico "is not likely to jeopardize the continued existence of any endangered or threatened species." Regulation of geophysical and other activities tied to the Endangered Species Act (ESA) and Marine Mammals Protection Act (MMPA) should proceed thoughtfully and cautiously. More scientific research should be conducted before any regulatory decisions are made.

c. Marine Protected Areas

Several mechanisms exist outside of OCS moratoria which restrict or prohibit exploration, development, and production activities. These means are both direct and indirect.

The most common and broadly used direct mechanism is marine protected areas (MPAs). This internationally used phrase may include national parks, marine sanctuaries, estuarine reserves, wildlife refuges, local, regional, and federal fishery management areas, critical habitats, wilderness areas, "no take" reserves and environmental sensitive areas. In the United States, almost 400 federal MPAs exist, comprised of almost 150 million acres.

Specific indirect mechanisms impacting industry's ability to develop natural gas reserves include nongovernmental advocacy organizations focusing on the conservation of ecosystems and biodiversity without taking into account the economic benefits of developing natural gas. Another indirect mechanism is the ratification of international conventions such as the Convention on Biological Diversity. This convention creates global obligations on the part of its signatories such as Canada and Mexico to consider protection of natural resources. The quest for protection of living natural resources often results in the restriction of long-term access to marine sites with potential non-living resources such as natural gas.

The most recent U.S. based activity on MPAs is the 2000 Presidential Executive Order. This order mandates enhancement and expanded protection of existing MPAs. Appropriate recommendations include assessment of threats and gaps in levels of protection currently afforded to natural and cultural resources, practical and science-based criteria for monitoring and evaluating the effectiveness of MPAs, and identification of opportunities to improve linkages with international MPA programs.

The natural gas industry supports the use of best available scientific data from adequately funded research with involvement from appropriate stakeholders, including industry, to consider the creation of MPAs and corresponding mitigation measures. The recognition of multiple use of the seas in existing and future MPAs is critical to the increased production of the nation's natural gas resources. The President and Congress must protect the balance between living marine resources and non-living marine resources and ensure MPAs are meeting their intended purpose.

d. National Energy Policy Activities Affecting OCS Access

The May 2001 Report of the National Energy Policy Development Group, Chapter 5, "Energy for A New Century: Increasing Domestic Energy Supplies," provides assessments, conclusions, and recommendations to support expanded future OCS energy access and development, but it does not suggest specific steps to increase leasing in areas of the OCS that are not available for leasing today.

e. Comprehensive Federal Energy Legislation

Comprehensive federal energy legislation could improve OCS energy access and supply development. Proposals before the 108th Congress contain several technical, economic, and policy enabling provisions, but no recommendations are included that would result in an increase in leasing in areas of the OCS that are not available for leasing today.

f. The MMS OCS Policy Committee

The MMS OCS Policy Committee is one of three advisory groups under the Minerals Management Advisory Board; it is chartered under the provisions of the federal Advisory Committee Act along with the scientific and royalty policy committees. The OCS Policy Committee gives advice related to discretionary functions of the Outer Continental Shelf Lands Act, representing the collective viewpoint of coastal states, environmental interests, industry, and other parties to the Secretary of the Interior through the Director of the Minerals Management Service. The Policy Committee over the last decade has prepared several thorough reports and submitted numerous recommendations concerning expanded OCS energy supply access. One of these recommendations is to develop information to enhance an informed public debate on whether or not there are grounds and support for a limited lifting of moratoria in existing moratoria areas. This recommendation calls for the MMS, in consultation with industry and affected states, to identify the five top geologic plays in the moratoria areas, and where possible, identify the most prospective areas for natural gas within these areas that industry would likely explore if allowed. Unfortunately, this recommendation and others that would lead to increased access to oil and gas resources have not been implemented.

The MMS OCS Policy Committee appears to have little influence and has become merely a venue for information updates and sharing. It appears that the state and federal government representatives are not empowered to make decisions that are binding on behalf of their state and/or organization. Many times, OCS Policy recommendations are met with opposition from the Administration and/or Congressional representatives from coastal states. A new design should be considered that allows coastal states and the federal government to reach consensus to move to implementation.

g. U.S. Commission on Ocean Policy

The U.S. Commission on Ocean Policy, established by the Oceans Act of 2000, will make detailed recommendations to Congress and the President in September 2003 concerning new ocean policy governance structures, fundamental ocean policy and resource principles, and a variety of specific implementation actions. If the Commission recognizes the environmental stewardship, technology, and economic contributions of OCS energy production, it should be in a position to make governance recommendations that will increase multiple use of offshore resources, thereby increasing supply. The Commission's recommendations should be implemented in support of environmentally responsible OCS energy development as a national priority, and in support of the other OCS energy recommendations in this report.

C. Canada

As other parts of this report clearly demonstrate, Canadian supply is an important source of natural gas supply for the United States during the period of the study.

As is the case in the U.S. Rocky Mountain Region, restrictions on the ability of industry to access and develop the Canadian resource base would negatively impact the benefits received by both the Canadian and U.S. economies. For purposes of this analysis it is assumed that the regulatory systems of both the Canadian federal government and the Provincial and Territorial governments with significant natural resource development possibilities will not be changed in ways that cause significant delays in the development of Canadian resources or cause significant increases in the costs associated with developing those resources.

A study prepared by the Canadian Energy Research Institute in 2003, "Potential Supply and Costs of

Natural Gas in Canada," (hereinafter referred to as CERI-2003), developed a resource assessment of Canada and details the current situation of natural gas access in western Canada. Currently, the Western Canada Sedimentary Basin (WCSB) – which is dominated by production from the province of Alberta – is the primary source of the majority of Canadian supply and is expected to continue to maintain that importance. Undiscovered natural gas resources underlying much of Alberta have similar production mechanisms and producing characteristics to the U.S. Rocky Mountain Region. These characteristics are also found in portions of British Columbia and Saskatchewan Provinces. Undiscovered gas resources are also expected to be present in the Northwest Territories and Yukon Provinces of northwestern Canada. The other principal regions of Canada with excellent potential are the Canadian West Coast in British Columbia and the Canadian East Coast (Newfoundland, Nova Scotia, and Labrador).

Each of these producing areas has special issues regarding access to resources. The area of Canada north of the 60th parallel is particularly constrained by severe weather and distance from development and production infrastructure. These access issues are reflected in the higher costs associated with resource development. Similarly, the producing areas of the Canadian East and West Coasts whether onshore or offshore are subject to significantly increased costs.

The harsh conditions of much of Canada require development of the resource during very short drilling seasons. These shortened seasons require extensive coordination among the exploration and development companies and the regulatory agencies. As this chapter will note later, the involvement of multiple regulatory agencies and regulatory overlap negatively impact the timing and coordination of these operations.

The CERI-2003 report reviews Canadian land status to determine availability for natural gas resource development. That analysis groups land into five categories of Restricted Areas. The extensive mapping effort locates (1) municipal areas, (2) National Parks, (3) Provincial Parks, and (4) water bodies (those larger than approximately 18 acres) and defines those areas as unavailable for development and operations. In addition, CERI-2003 locates Special Protected Areas that have use restrictions that significantly increase the costs of operations because of seasonal restrictions or other special requirements.

The portions of the various natural gas plays studied by CERI-2003 that are defined as "no access" or are defined as Special Protected Areas varies from a high of slightly over 50% in the Foothills play to statistically insignificant percent in some other plays. Overall the portion of each Province or Territory as a whole that is unavailable for development or is subject to particular restrictions varies from 11% in British Columbia to none of the area of the East Coast. In the other Provinces or Territories, approximately 3% of the land area is subject to these formal access restrictions.

Beyond these land classifications, several access issues are present or emerging in areas of Canada that threaten to negatively impact development of Canadian natural gas.

1. Aboriginal Issues

For several decades, Canada has intermittently negotiated with First Nations, principally in the Northwest Territories, to establish treaties governing and settling First Nations land claims. This sometimes-lengthy process can have a significant impact on natural gas exploration, development, and transportation. Industry is concerned that dissatisfaction with the process of those negotiations or lack of progress of those negotiations will limit the ability to develop the significant natural gas reserves that underlie these lands.

Likewise, the federal government and the several provincial governments have been involved in continuing discussions of the devolution of governance authority from the federal government to the provinces. These governmental discussions and the resultant uncertainty are of concern to industry. A speedy conclusion to these discussions is desirable in order to provide a more stable and predictable regulatory environment for operations.

In addition, the Crown (through the federal government) has a legal obligation to consult with Aboriginal peoples, whose constitutional rights and interests are potentially affected by energy development. Legal and political challenges regarding inadequate consultation with Aboriginal peoples continue to affect all levels of government and create uncertainty for the energy industry.

2. Landowner Issues

Additional areas of concern for Canadian natural gas producers are a set of landowner issues similar to those being confronted in the U.S. Rocky Mountain Region. Canadian regulatory agencies typically detail a process of public consultation required of an operator. This process of advanced notification and consultation varies depending on the nature of the proposed operation and the nature of the expected natural gas stream, i.e., sweet gas or sour gas and whether flaring of gas is anticipated as part of the normal operations procedures. Increasingly these planning, notification, and consultation processes are adding significant delays and costs to operations. Industry needs stability and certainty in these requirements to allow measured judgments of the time and costs that need to be planned for in natural gas operations. Industry is committed to meet or exceed all reasonable environmental, safety, land use, and reclamation/remediation requirements and is committed to work with all regulatory agencies and interested parties to resolve concerns.

3. Wildlife Issues

Special land use restrictions have been imposed in areas inhabited by rare or endangered wildlife populations such as grizzly bears and caribou. Industry recognizes the special needs to protect these species based on careful, scientifically based study and is committed to responsible stewardship of these species through recovery planning and implementation of species management programs. However, industry is concerned that unnecessary restrictions or delays in developing guidelines for operations in these sensitive areas will negatively impact reasonable resource access.

4. Surface Uses

One common theme in both the United States and Canada is the increasing conflicts among different surface users. The interests of the mineral resource developers, agricultural users, the forestry industry, and recreational users sometimes are at odds with one another. Industry is committed to continuing to engage all of these stakeholders in ongoing discussions to seek reasonable accommodation with these competing interests.

5. Governance

The natural gas industry in Canada would benefit from more consolidated and responsive governmental and regulatory processes. Industry recognizes that the group of active and concerned stakeholders affected by natural gas development is growing. These concerns must be addressed at all operational levels. However, industry believes that more stable, responsive, and clearly defined governmental systems are crucial to addressing these concerns, and are a necessary and judicious approach to maintaining a healthy and productive natural gas industry in Canada.

D. Access-Related Sensitivities

1. Sensitivity Case Summaries

To estimate the potential effects on price and recoverable natural gas resource of future implementation of the Onshore and Offshore recommendations contained in this report, the NPC commissioned several modeling sensitivities to be run by EEA. Since the Reactive Path scenario described elsewhere in this report assumes that current restrictions to access will remain constant throughout the scope of this study, the NPC also commissioned a reduced access case designed to estimate the impacts that could accrue from a continuation of the steady increase in restrictions that have taken place in the United States over the last 30 years.

The Balanced Future scenario included increased access assumptions that are combined with two sensitivities discussed below – the Gradual Increase Rockies Access case and the Increased Offshore Access case.

a. Increase Rockies Access Supply Cases

The NPC determined it would be useful to perform two enhanced access cases as a part of its modeling work: (1) an analysis designed to estimate the impact of the current regulatory regime (the "Full Effect Case") on natural gas prices and available resource; and (2) an analysis designed to estimate the potential positive impacts from the implementation of the public policy recommendations contained in this report (referred to herein as the "Gradual Increase Case") on prices and available resources.

In running these two cases, the following assumptions were made:

- **Full Effect Case.** The cost and timing restrictions arising from the cumulative effects of post-leasing COA are immediately lifted. The percentage of the resource that is off-limits to leasing by statute remains unchanged. It is important to note that this case is not intended to advocate the repeal of these COAs. Rather, it is simply intended as a means of estimating the impacts in terms of higher prices and foregone resource of the current regulatory regime. As noted elsewhere in this report, the NPC fully recognizes and supports efforts by the various governing agencies to protect endangered species, wilderness areas and archaeological artifacts.

- **Gradual Increase Case.** The cost and timing restrictions arising from the cumulative effects of post-leasing COA are decreased by 50% over a five-year period beginning in 2004. As in the other cases, the percentage of resource off-limits to leasing by statute remains unchanged.

b. Increased Offshore Supply Access Case

In the OCS, the NPC wanted to test the potential effects on the price and available resource from a lifting of the presidential moratoria that are currently in place on the Atlantic and Pacific coasts of the U.S. lower-48, as well as the Eastern Gulf of Mexico. In this case, the following is assumed:

- The moratorium ends in July 2005.
- Leasing of offshore tracts does not commence until July 2007. This two-year period is to allow time for federal, state and local jurisdictions to develop the agencies needed to manage this activity, and for appropriate areas for leasing to be selected.
- Full-scale production does not commence until 2012 to allow time for seismic analysis, exploratory and development programs.

c. Decreased Supply Access Cases

For the decreased access cases, the NPC made the following assumptions:

- The costs and timing delays arising from post-leasing COA in the Rocky Mountain area double over a period of 10 years beginning in 2004. This includes the average added cost per well, the average initial time delay, and the percentage of resource that becomes effectively off-limits to development. In the judgment of the Rocky Mountain Expert Team, this gradual increase approximates the increase that has taken place during the prior decade.
- The percentage of resource statutorily off-limits to leasing as quantified in the 2003 EPCA Report remains unchanged.
- The total “No Access” percentage of resource (statutory + COA) in each basin was capped at no more than 50%.
- In the OCS, the model assumed a one-year halt in drilling takes place in 2005, and the environmental cost of compliance doubles over a ten-year period.

2. Sensitivity Modeling Results

a. Onshore

Figure S6-6 shows Rockies production through 2025 for the four access cases. Looking at the year 2020, the greatest amount of production is from the Full Effect increased access case. The next greatest production is from the Gradual Increase case, followed by the Reactive Path scenario and the Decreased Rockies Access case. Looking at the full range of forecast production in 2020, the model shows that the effect of access restrictions on Rockies production could be up to 2 TCF/year by 2020.

One way to forecast the likely impact of current access restrictions would be to look at the difference in production in the Reactive Path scenario and the Gradual Increase case. This is because the Full Effect case, as described previously, was developed only to gauge the impact of all current non-statutory restrictions. However, as mentioned earlier, the Reactive Path scenario assumes that the current level of COA-related impacts will remain static throughout the scope of this study, which is not consistent with the steady increase of such impacts that have taken place in recent years. Thus, the NPC believes it is more relevant to compare the Gradual Increase case to the Decreased Rockies Access case, which assumes that this trend towards more COA-related restrictions will continue absent significant changes in public policy. The difference between these two cases in 2020 is between 1.0 and 1.5 TCF/year.

i. Evaluation of Full Effect of Current Restrictions

The Full Effect case was developed to estimate the impact of the current regulatory regime on prices and gas production. In order to make this assessment, a comparison of that case to the Reactive Path scenario is most relevant, given that the Reactive Path scenario assumes the continuation of the current level of restriction. Figure S6-6 shows that the lower-48 production difference in these two cases in 2020 is greater than 1 TCF/year.

As an example of the impact shown by the Full Effect case, one can look at the effect on the California market. The impact of access restrictions in the Rockies has an effect on market conditions in California. Gas production in California only meets about 15% of the state's demand, leaving the balance to be imported via interstate pipelines. As shown in Figure S6-7, approximately two-thirds of the imports currently come from the Rocky Mountain Region, projected to reach three-quarters by 2020.

The impact of Rockies access restriction on southern California prices is shown in Figure S6-8. As expected, the Gradual Increase Rockies case begins to show an easing of prices as the impacts of the COA are reduced beginning in 2004, and results in a consistent price differential when compared to the Reactive Path scenario of 30-50 cents per million Btu in the later years of this study.

The price differentials between the Rockies Full Effect case and the Reactive Path scenario multiplied by the projected volumes going to the California market in this study indicates that the current set of restrictions related to COAs will cost the California consumer roughly $18 billion between 2003 and 2025. It should be noted that the Rockies Full Effect case is not intended as an advocacy piece for the repeal of the existing protections for endangered species, archaeological sites and the environment. As mentioned elsewhere in this report, the NPC recognizes the need for these protections, and fully supports their continued use. This case is simply an effort to estimate the cost to the consumer of the current statutory/regulatory regime, and point up the need to ensure that these laws and regulations are enforced in an efficient and cost-effective manner.

b. Offshore

Figure S6-9 shows the increased production in the eastern Gulf of Mexico, with production more than doubling by 2025.

The impact on South Florida prices are shown in Figure S6-10. As seen in Figure S6-10, the running of these sensitivity cases results in a significant price impact for the South Florida area.

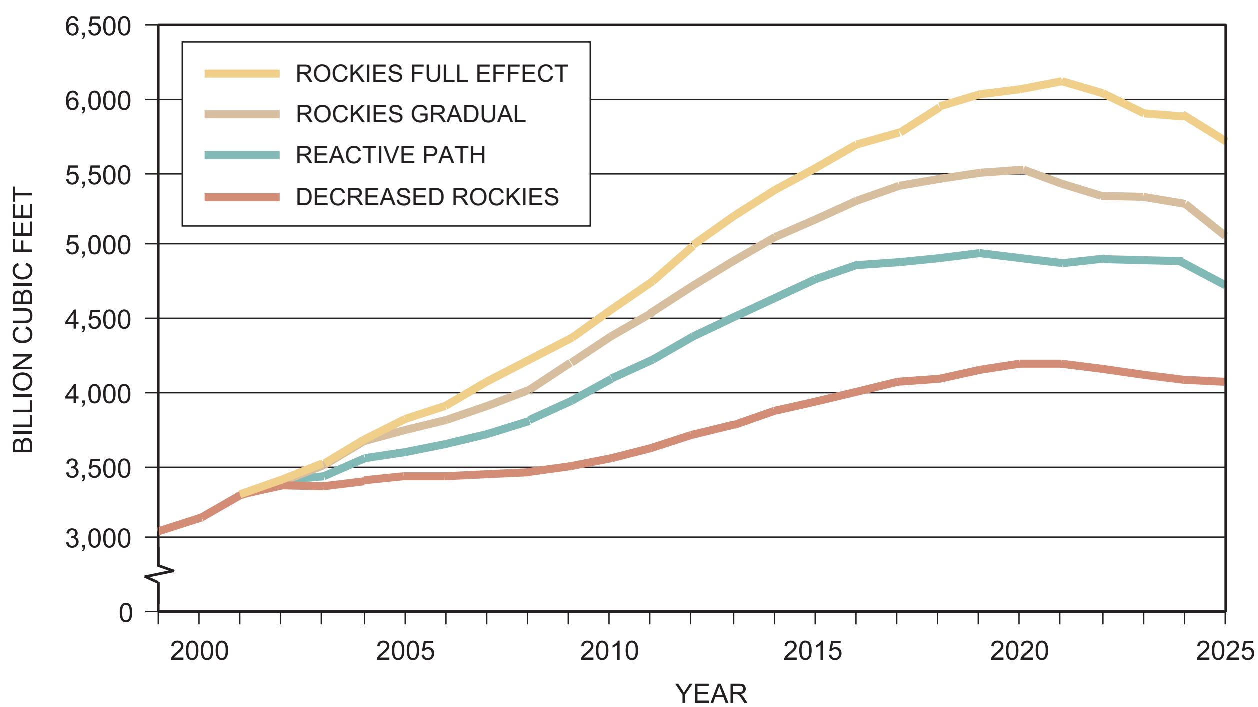


Figure S6-6. Rockies Gas Production

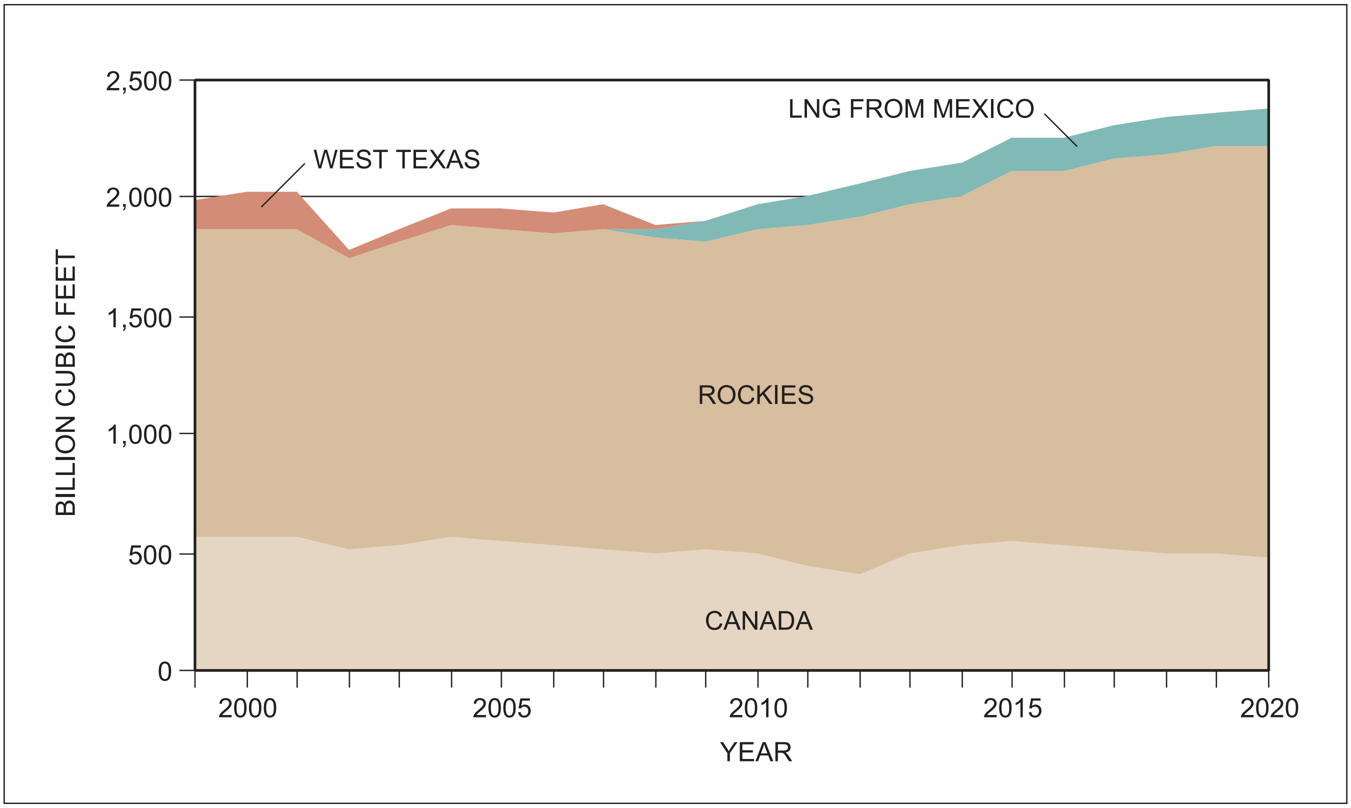


Figure S6-7. Pipeline Imports into California – Reactive Path Scenario

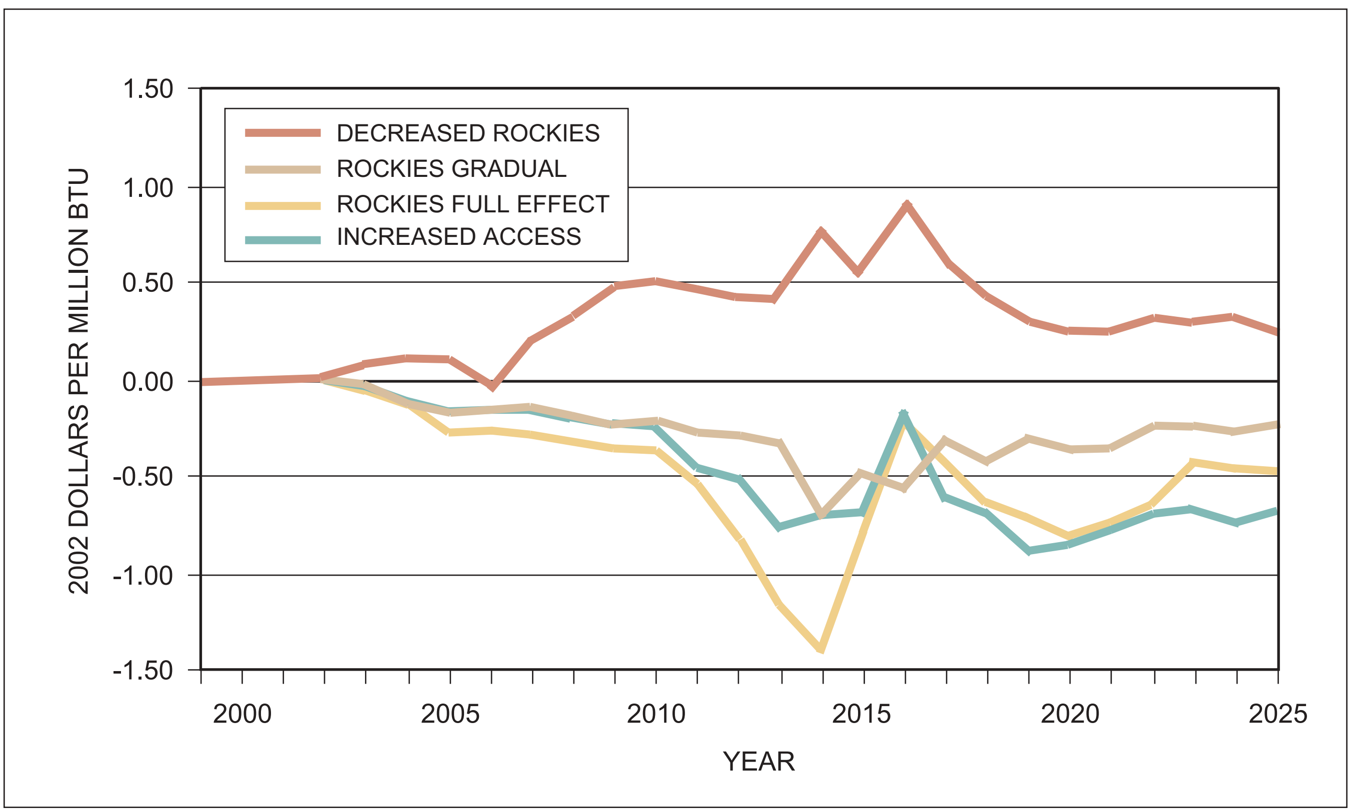


Figure S6-8. Change from Reactive Path Scenario – Southern California

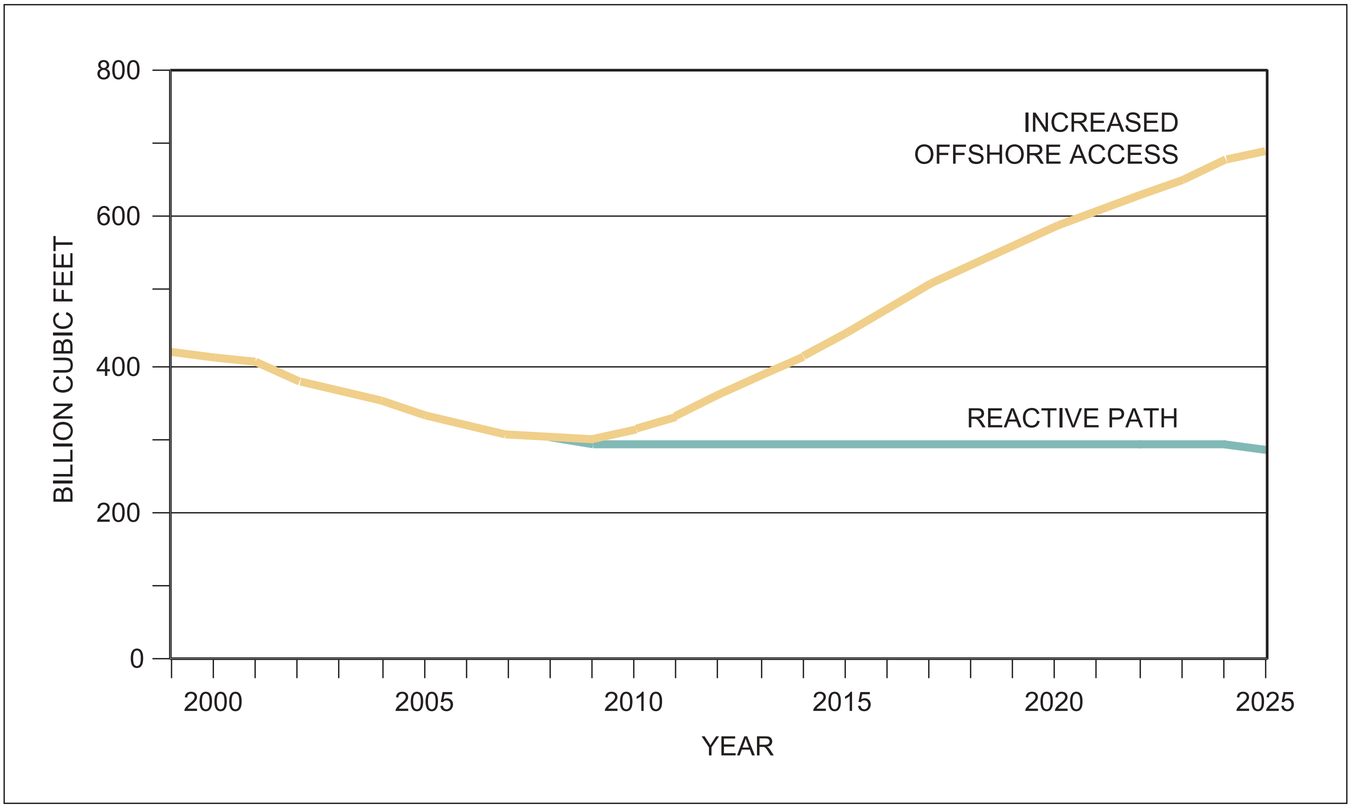


Figure S6-9. Increased Access – Eastern Gulf of Mexico

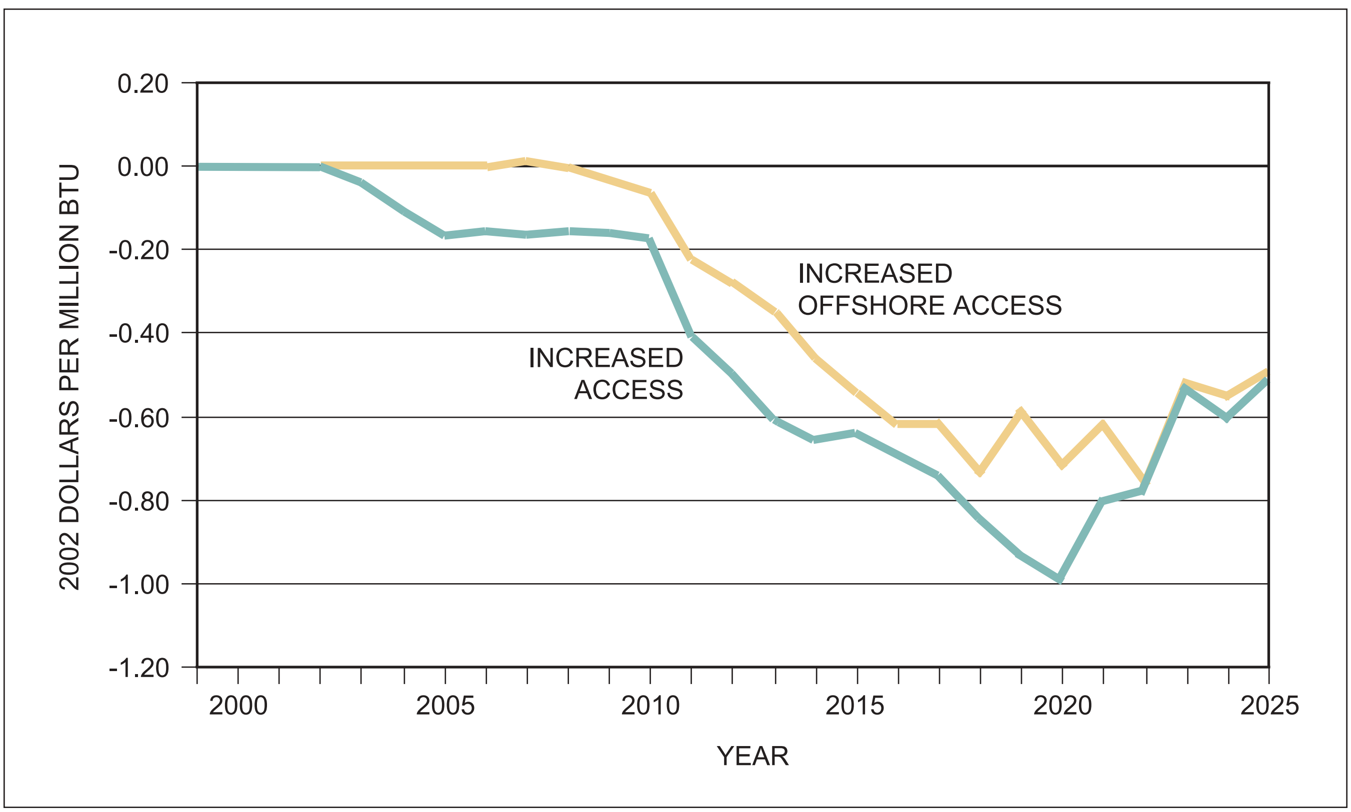


Figure S6-10. Change from Reactive Path Scenario – South Florida

As shown in Figure S6-11, the Increased Offshore Access case shows a steady ramp-up of new volumes from the Offshore Atlantic, due to the assumed lifting of existing moratoria on oil and gas exploration and production activities, beginning in 2011, growing to almost 700 BCF/year by 2025.

As noted elsewhere in this chapter, the inability of MMS to obtain more current data and update its inventory estimates in these OCS areas makes it very likely that these resource estimates are significantly understated. The artificially low volume numbers in turn will in turn dampen the impact on available volumes and prices shown by the modeling sensitivity runs.

3. Conclusion

Overall, the results of the access-related sensitivity cases that were run by EEA support the rationale for the public policy recommendations that appear in the next section of this report. None of the recommendations would in and of themselves become a panacea for alleviating the tight supply and demand outlook forecast by the Reactive Path scenario in this study. However, when taken as a whole, the NPC believes that the prompt implementation of these public policy recommendations would effectively increase the amount of recoverable natural gas resource in the lower-48 areas of the United States, which in turn would have a significant impact on prices paid by consumers.

E. Public Policy Recommendations

In its 1999 natural gas study, the NPC stated the following: "A clearly delineated public policy supporting development of ample supplies of natural gas is critical in order to satisfy growing demand at reasonable prices." What was true in 1999 remains true today. No single factor is more critical to the task of meeting the growing demand for natural gas in the United States than the government's assurance that the industry can obtain and maintain access to the lands and waters under which the resource lies. As already detailed, a very significant percentage of the known domestic natural gas resource has already been placed off-limits by an array of administrative and political decisions, statutes, regulations, and policies. This percentage has grown significantly over the last fifteen years, and a continuation of that growth would impair the domestic industry's ability to produce adequate supplies of natural gas in the future.

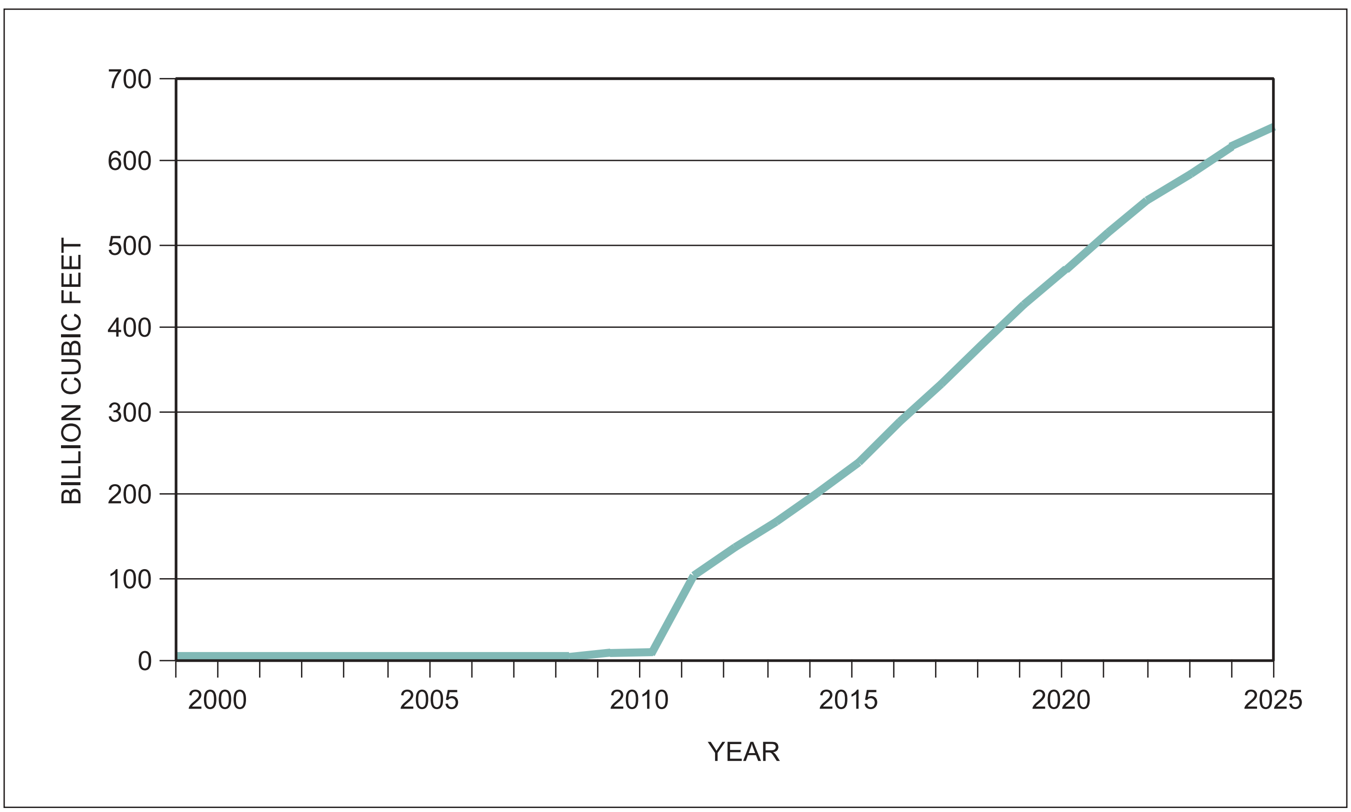


Figure S6-11. Increased Access – Atlantic Offshore

The NPC fully recognizes and supports the obligations of the state and federal governments to protect endangered species, marine mammals, historical structures and artifacts, and the environment in which we all live. At the same time, the NPC also recognizes the need for the government to balance those considerations with the need to ensure that adequate supplies of natural gas are available at reasonable prices for the benefit of future generations of Americans.

The public policy recommendations contained in this report do not advocate that national park lands, national monuments created by executive order, or other wilderness areas that are statutorily off-limits to leasing be opened to oil and gas exploration and development activities. In addition, these recommendations are **not** designed to roll back necessary protections for endangered species and marine mammals, the environment or the nation's archaeological treasures. Rather, they are designed to speed up and increase access to natural gas resources through streamlined processes, improved communication, enhanced cooperation, increased collaboration, and reduced costs and delays for both the industry and the various government agencies charged with dealing with these issues, while fully protecting this Nation's national treasures. For purposes of clarity, the recommendations are segregated into separate Onshore and Offshore sections.

More detailed, issue-specific recommendations may be found along with the detailed issue summaries located in Sections II and III of this chapter.

1. Onshore Recommendations

As discussed in the section on access-related sensitivity cases that were run in the modeling process of this study, the NPC estimates that the implementation of these recommendations over a five-year timeline would reduce the prohibitive effects of COAs – time delays, costs, and the amount of resource effectively off-limits to development – by 50%.

a. Onshore Advisory Task Force

The Secretary of the Interior, in consultation with the Secretaries of Energy and Commerce, should charter an advisory committee under the Federal Advisory Committee Act, designed to address access issues in the Western interior region of the United States. The Committee's charge would be to review the various statutory and regulatory regimes that govern use of public lands in these states, and make recommendations designed to reduce redundancy, streamline processes, reconcile conflicting policies within or between government agencies, and ensure that regulations are enforced in a manner consistent with their original intent. The Committee's membership should consist of directors or their first-line deputies of the relevant federal and state agencies, industry executives, representatives of other users of public lands such as ranchers, and interested parties from the general public.

b. Endangered Species Act

Because there are no qualification requirements to nominate a species for listing, species are frequently proposed by groups and individuals for the express purpose of utilizing the Endangered Species Act as a tool to hinder land management planning and project permitting. This has created such a backlog that nominated species are given the same level of protection as listed threatened and endangered species without supporting scientific data. Consideration should be given to modifying the Endangered Species Act to:

- Require listing petitions to be based on the best available scientific and commercial information, and develop specific criteria for what constitutes best available data
- Require independent scientific peer review and a socio-economic impact analysis before listing
- Develop standards and criteria to determine whether listing is in the national interest.

c. Land Use Planning

Federal land management agencies are required to prepare land use plans that allocate public lands uses, protect economic and environmental resources and values, and establish future management direction. Provision of reasonable access to energy resources while protecting environmental values is a key challenge for land managers and producers. A viable federal leasing and project permitting program will result if the following recommendations are incorporated in planning:

- Agencies should use Reasonably Foreseeable Development scenarios as a planning tool and refrain from using it to establish surface disturbance limitations.

- Land use plan and project monitoring needs to be established as a high priority in order to gather information (e.g., condition and trend of wildlife habitats) that can be used in subsequent plan revisions and project permitting, and to make science-based determinations about the efficacy of lease stipulations and conditions of approval.

- Maximize land use planning and cost efficiencies by including both the 36 CFR 228 Part 102 (d) & (e) leasing decisions in Forest Service land use plans.

- Ensuring there is adequate BLM and Forest Service minerals personnel with the requisite expertise required to meet land use plan, leasing and project permitting expectations.

d. Wilderness (including Forest Service roadless areas)

Many areas that have high potential for the occurrence of natural gas are either in wilderness study area (BLM) or inventoried roadless area (Forest Service) status. BLM wilderness study areas (26.5 million acres) are off-limits to leasing until Congress decides whether to designate them as wilderness or release them to multiple use. Road construction and re-construction is prohibited on inventoried roadless areas (58.5 million acres). On July 14, 2003, U.S. District Judge Clarence Brimmer of Wyoming issued a permanent injunction denying the Forest Service the right to enforce its roadless policy on these inventoried roadless areas. Given that the government may appeal this ruling, the status of these inventoried roadless areas is uncertain at the time of the publication of this report. Regardless of the outcome of this litigation, the ability of natural gas producers to meet future natural gas demand will be enhanced if the following recommendations are implemented:

- Modify the Forest Service's roadless rule to exempt oil and gas exploration and development activities because such activities are temporary in nature, subject to extensive environmental regulation and are fully reclaimed after production ceases.

- Identify and open to leasing inventoried roadless areas that contain natural gas resources. A recent DOE study conducted by Advanced Resources Inc. concluded that roughly 80% of the natural gas resources underlying these 58.5 million acres could be developed by allowing access to 5% of the land area.

- An April 2003 DOI settlement on wilderness re-inventory allows nominated tracts in Utah and Colorado that are adjacent to or in wilderness re-inventoried areas to be leased. Utah BLM should move expeditiously to post nominated tracts for lease sales.

e. Staffing

Congress should ensure that staffing for land management agencies is fully funded to enable the accomplishment of the following goals:

- NEPA/Planning – Land use plans need to be timely updated in high potential areas to authorize leasing and drilling activity.

- Leasing and Permitting – Lease nominations and project permits need to be handled expeditiously.

- Appeals and Protests – Citizen appeals and protests of BLM decisions need to be resolved in a timely way to reduce risk.

- Delegate an "APD Focus Team" to assist field offices with high permitting workloads.

f. Permitting

Increased resource production can be realized by streamlining improvements in the following areas:

- Performance goals and targets need to be set for each office, e.g., 90% of APDs must be completed within 35 days, and implement performance enhancement actions if these goals/targets are not met.

- Eliminate on-sites for conflict free wells in established fields.

- Use categorical exclusions for wells and ROWs that require minimal surface disturbance in existing fields.

- Encourage use of joint APD/ROW applications for gas wells.

- Use sundry notices instead of APDs for successive wells on multi-well drill pads.

- Use sundry notices for downhole operations and establish a 15-day timeframe for approval.

- Use the "APD Focus Team" to provide assistance to field offices.

g. Cultural Resources

Due to liberal interpretation of current regulations, operators are frequently required to perform exhaustive cultural resource studies far beyond the scope of their projects. Such in-depth research is the responsibility of state and federal agencies and should not become the sole responsibility of the operator. Operators may, however, voluntarily elect to cover a portion of the expense.

- Current regulatory requirements should be revised to limit an operator's responsibility to locating a site by cadastral survey and, in the absence of an agency archaeologist, for the cost of an authorized contract archaeologist to identify archaeological, historical, or vertebrate fossil materials discovered during construction. Current requirements (suspension of operations that further disturb the discovered materials, immediate notification of the authorized officer, and resumption of operations only after written authorization is issued by the authorized officer) should remain in effect.

- Improved methods for determining site significance are critically needed. Consultation should not be necessary if a site is not unique or lacks significance.

- BLM should ensure its national historic trail and visual resource management guidelines are used objectively and consistently to avoid unintended effects to private landowners, lessees, and state and federal revenues.

h. NEPA Process

Considerable frustration exists around the inability of agencies to meet NEPA requirements in a timely and efficient manner. It is imperative that agency-specific accountability and performance metrics are developed and implemented to measure and report results to the public and Congress. The Council on Environmental Quality's (CEQ) 1997 report "The National Environmental Policy Act, A Study of Its Effectiveness After 25 Years" offers many positive and effective recommendations that should be implemented by agencies. Further recommendations include:

- Directing federal agency compliance with CEQ regulations at 40 CFR 1500 to 1508 (e.g., scope of environmental analysis, public participation, and documentation) and relevant executive orders (e.g., requiring permit streamlining and energy impact assessments)

- Setting performance goals and targets, along with performance enhancement measure, for action on leasing and permitting for each BLM office, and reporting results to the public

- Developing internal programs aimed at improving information exchange and technology transfer with other agencies, and the manner by which relevant or new information from inventory, monitoring, research, and planning activities is incorporated in land use plans.

2. Offshore Recommendations

a. Removal of OCS Moratoria

The President, Congress, and state governors should review the rationale for continued moratoria on leasing and development of prospective natural gas resources. A review process should be structured to identify current moratoria areas containing high resource potential, with a view towards beginning the lifting of these moratoria in a phased approach beginning in 2005. The President and Congress should consider all currently existing factors when conducting this review, including but not limited to:

- The outlook for constrained domestic supply in the face of increasing demand for natural gas

- The significant natural gas resources that underlie the waters currently subject to presidential order moratoria

- The environmental advantages of producing and transporting OCS natural gas, especially the use of natural gas in industrial and power-generating applications

- The outstanding safety and environmental record demonstrated by the oil and gas industry in other OCS areas over the last 30 years.

The NPC recognizes that the decision to rescind these moratoria could result in a very politically charged debate, similar to that which occurred around the decision to close certain military bases in the 1990s. To largely remove the base closing decisions from the political arena, Congress and the Bush Administration formed the bipartisan blue-ribbon Base Realignment and Closure Commission, which took on the task of making these difficult decisions. Given the critical role the OCS will continue to play in meeting our national demand for natural gas, Congress and the current

Administration should consider a similar approach to this issue.

b. OCS Leasing of Available Lands

The Department of the Interior should provide access to all OCS areas not under moratoria in the 2007-2012 OCS 5-Year leasing program and continue to ensure access to the current 2002-2007 5-Year Leasing Program. Access to areas available for leasing is crucial if industry is to meet the growing demand for natural gas in the United States.

c. OCS Education and Outreach

The Secretary of the Interior, in consultation with the Secretaries of Energy and Commerce, should launch a process that will lead to an energy education and outreach program encouraging a national dialogue about the existing and potential role of OCS-derived natural gas in meeting our nation's energy needs. Congress should fully fund such a program. DOI should assess all existing education and outreach efforts with regard to ocean resources, inside and outside government, with the goal of increasing public/stakeholder awareness of OCS natural gas activities and the key role it plays in this nation's economy. To achieve balance and objectivity, any such education and outreach program must incorporate into the OCS natural gas perspective the concerns of stakeholders, including coastal community impacts and environmental concerns. The progress of such a program needs to be monitored and measured to ensure changes in public attitudes and knowledge of offshore issues is occurring.

d. Consideration of Existing Studies

Numerous other studies and recommendations have been developed to address energy availability. Some examples are "Energy for a New Century: Increasing Domestic Energy Supplies," 1998 *OCS Policy Committee Subcommittee on Environmental Information for Select OCS Areas,* "2001 Report from the Subcommittee on Natural Gas OCS Policy," "OCS Policy committee Subcommittee on Environmental Information for Select OCS Areas," "2003 Report of the Subcommittee on Education and Outreach" of the OCS Policy Committee, and the U.S. Commission on Ocean Policy principles and recommendations. Additional information on these is found in Section III of this chapter. The Department of Interior in consultation with key stakeholders including states, industry and NGOs, should review the recommendations from these various studies and compile them into a single set of comprehensive recommendations and action items for submission to Congress. Congress should consider supporting the implementation of these recommendations.

e. OCS Energy Permit Approvals

Congress should make statutorily permanent the requirement that all decisions regarding access to the OCS must consider impact on the nation's energy supply, distribution, and use, and decision makers must be held accountable for the impact their decisions will have on energy supply. To promote the timely approval of OCS energy permits requiring input from multiple agencies due to the requirements of certain laws like the Coastal Zone Management Act, Marine Mammals Protection Act, Endangered Species Act and other such statutes, Congress should support the permanent formation of an office in the Executive Office to coordinate the efficient approval of these type of permits. Congress should provide full funding to the agencies so they conduct all the necessarily research, analysis and approvals of OCS-related natural gas activities in a timely fashion.

f. The OCS and the Role of States

Congress should support mitigation of any negative impacts OCS development may have on infrastructure and coastal communities by directing a portion of the bonus bids and royalty revenue stream from existing royalties to affected coastal states. Additionally, the OCS royalty stream should be reviewed has a possible funding source of MMS activities that support the OCS oil and gas program.

Congress and the Administration should consider legislative proposals that would definitively establish the roles and responsibilities a coastal state has with regard to reviewing and taking a role in OCS leasing and development activities based on distance from the shorelines to OCS activities, and distribute OCS revenues to the coastal states according to these leasing "zones." At some distance seaward from the shoreline, the federal government should have the sole discretion to lease OCS resources. Congress, the Administration, and coastal states should establish such leasing guidelines.

g. OCS Inventory

Congress should provide MMS funding and authority to obtain a more accurate assessment of the OCS resources. This would include working with affected stakeholders, including coastal states. This assessment would analyze how resource estimates in the OCS areas have changed over time as (1) geological and geophysical data was gathered; (2) initial exploration occurred; (3) full field development occurred, including areas such as the deepwater and subsalt areas in the Gulf of Mexico. The assessment should also include an analysis of the effect that understated oil and gas OCS resource inventories have on domestic energy investments and the U.S. economy.

h. Coastal Zone Management

- If a state alleges that a proposed activity is inconsistent with its CZM Plan, it should be required to specifically detail the expected affects, demonstrate why mitigation is not possible and identify the best available scientific information and models which show that each of the affects are "reasonably foreseeable."

- State CZM Plans should not be approved by the Secretary of Commerce if such implementation would effectively ban an entire class of federally authorized and regulated activity.

- Changes to federal CZM regulations should be made which would provide for a single consistency certification process for proposed outer continental shelf oil and gas activities which covers all federally licensed or permitted activities, including air and water permits.

- Ensure timely action by the Secretary of Commerce is taken with regard to state appeals under the Coastal Zone Management Act (CZMA). Set specific deadline (120 days) for decision on appeal with limited opportunity for extension of that deadline if more time is needed.

i. Endangered Species Act/Marine Mammals Protection Act

- Regulatory changes designed to protect marine species should be based on best available scientific information and data to avoid inappropriate or unnecessary action could be taken with no benefit to the intended species.

- Certainty and predictability are key elements to offshore access and therefore lessees need to know what will be required of them as early as possible in the leasing/permitting cycle. Reasonable lease stipulations and operational measures designed to protect listed species should be practical and cost effective and aimed to achieve minimal delays in ongoing operations.

- More research must be conducted before implementing unwarranted mitigation measures. Congress should provide funding to NOAA and MMS to study the relationship between oil and gas activities and marine mammals in the Gulf of Mexico, with the initial focus on sperm whales. Additionally, the Administration should ensure that the ESA/MMPA regulatory processes are well coordinated between NOAA and MMS.

j. U.S. Commission on Ocean Policy

The Commission's guiding principles and recommendations, currently being drafted, must be implemented in a manner consistent with the following energy-oriented principles to effectively support improved OCS resource access and development:

- Recognition of the role of OCS energy production as part of national energy policy, and the need for mixed and balanced use of all resources.

- Given their long history of success, experience, and expertise, maintenance of the DOI/ MMS role as manager of offshore energy development.

- Utilization of existing federal agency authorities and ocean governance laws for enhanced coordination and conflict resolution mechanisms.

- Evaluation of recommendations to ensure they address well-documented resource problems – such as the CZM process – and provide for a real opportunity for improvement.

- Balanced consideration of environmental, economic, technical feasibility, and scientific factors in conflict resolution and policy coordination.

- Enhancement of regulatory process certainty in ocean resource management.

F. Conclusion

The last two decades have been marked by a clash of competing national policies where the subject of natural gas is concerned. On the one hand, the federal and state governments of the United States have recognized the desirability of natural gas as the cleanest-burning fossil fuel. The government has as a matter of policy encouraged utility companies and other industrial users to fuel their plants using clean-burning natural gas. These policies have greatly assisted the government in meeting its environmental objectives for the nation.

At the same time, however, the government has systematically withdrawn a steadily increasing share of federal and state lands and submerged lands from access for exploration and development activities. The government has also created an increasingly complex and costly set of statutory, regulatory and administrative requirements that render a significant portion of lands in the Rockies effectively off-limits to development, even though they are technically available for leasing, as demonstrated in this report.

The clash of these two competing sets of policies has helped to create a business environment in which domestic demand for natural gas is on the rise, yet industry finds it increasingly is unable to access the lands under which much of the nation's remaining reserves of natural gas are located. The NPC believes it is possible to meet the nation's environmental/endangered species goals while at the same time encouraging fuller development of these critical natural gas reserves.

The NPC urges the government to give serious consideration to the implementation of the policy recommendations contained in this report, recommendations that would enable the industry, government and other interested parties to work together to develop and implement innovative approaches and solutions to these difficult and complex issues.

II. Onshore Public Policy Recommendations

A. Interagency Coordination for Land Management Planning and Environmental Analysis

Issue: The National Environmental Policy Act (NEPA) requires agencies to share information and integrate planning responsibilities early in the process of preparing land management plans or project-related environmental documentation. Recent experience with Rocky Mountain area NEPA documents demonstrates land management agencies need to focus their efforts to improve interagency coordination in order to conform with original congressional intent.

The public has expressed considerable frustration in recent years regarding the inability of agencies to perform their NEPA responsibilities in four main areas:

- Ever-increasing taxpayer expense and time required to perform the analysis
- Enormous efforts required to review and comment on exhaustive and cumbersome documents
- Concern whether public and lessees' issues were understood and received due consideration
- Concern whether an agency with relevant expertise and jurisdiction was involved at the appropriate time in the process.

Impact: Effective interagency coordination is necessary to ensure timely, balanced, scientific, comprehensive and efficient preparation of land use plans and project-related environmental documentation. Poor coordination among state and federal agencies adds cost, delay and controversy for all parties, as well as appeals and protests that could have been avoided. If determined efforts to improve interagency coordination are not made, public distrust and agency credibility challenges will continue to escalate.

Recommendations:

- All state and federal agencies should be required to disclose to the public how and when interagency coordination will be performed whenever land use plans or project-specific environmental analysis are prepared. This plan should be consistent with the Council on Environmental Quality's (CEQ) requirements for agency involvement, coordination and timing as well as regulatory jurisdiction or responsibility.
- It is imperative that agency-specific accountability and performance metrics are developed and implemented to measure progress and report results to the public and Congress. Industry and public expectations would be better served if agencies adopted recommendations from the 1997 CEQ report "The National Environmental Policy Act, A Study of Its Effectiveness After 25 Years."
- Each agency should be required to develop internal programs that improve information exchange with other agencies and the manner by which relevant or new information from inventory, monitoring, research, and planning activities is incorporated.

- Defined interagency coordination roles and responsibilities for each agency would improve coordination efficiency while eliminating waste and duplication. Common timeframes and information exchange requirements are key to expedite completion of land use plans and project-level NEPA documents.

- Adoption of effective quality control and assurance measures is necessary to ensure timely communication and consistent enforcement of federally delegated environmental management and compliance programs.

- CEQ regulations at 40 CFR 1500 to 1508 establish clear expectations for each step of the NEPA process for all federal and state agencies and other parties such as Tribes, special interest groups and the general public. No new legislation or regulation is necessary to make significant interagency coordination improvements.

- It is recommended that each agency evaluate the report and recommendations published by the CEQ's NEPA Task Force and the Rocky Mountain Energy Council when they become available and develop program guidance accordingly.

- Lead agency project managers should assume responsibility for internal and external project coordination, such as identifying information needs, ensuring availability of resource staff, ensuring schedules and public commitments are kept, and designating contact and review personnel.

- When land use plans and project level NEPA documents are prepared by third party contractors, agencies need to develop action specific guidance that enables timely review and work progression. Areas of concern include:

  – Availability of personnel and resource specialists

  – Commitment of resources to perform research and to provide assistance with document preparation and review

  – Setting schedules and ensuring they are met

  – Communicating priorities to line managers and staff to ensure their availability throughout the process

  – Ensuring exact requirements and scope of analysis are identified for contractors.

B. Compliance with Cultural Resource Management Requirements

Issue: In 1966, Congress passed the National Historic Preservation Act (NHPA). The Advisory Council on Historic Preservation was created under Title II of the Act to "advise, encourage, recommend, review, inform, and educate." Section 106 of Title I is the operative part of the Act stating: "…and Federal agency…shall…take into account the effect of the undertaking on any district, site, building, structure, or object that is included in or eligible for inclusion in the National Register. The…Federal agency shall afford the Advisory Council on Historic Preservation…a reasonable opportunity to comment with regard to such undertaking." NHPA affects public lands as well as private and state lands where split estate ownership exists.

Impact: Delays and costs associated with cultural resource clearance can be major deterrents to exploration and production. For example, performance of a Class III survey (recordation of all cultural properties that can be identified from surface indications in a specific area) and resolution of possible effects can take up to 30 days if no cultural resources are found and costs from $1,500 to $4,000 depending on acreage. If cultural resources are found, operators typically relocate their projects, subject to topographic and other constraints, in an effort to eliminate or reduce impacts. If there is a significant discovery and impacts from project implementation cannot be avoided, expenses can easily run into the hundreds of thousands of dollars for a large gas plant, to millions of dollars for an interstate pipeline. These expenses are for cultural resource surveys and reports, project re-location and re-surveys, construction monitoring, testing of archaeological and historic sites, and preparation and implementation of research designs. Of concern, the extent of mitigation is wholly determined by agencies and there are no caps on expenses. Finally, resolution of conflicting mitigation requirements from the Bureau of Land Mangement (BLM), the State Historic Preservation Office and the Advisory Council on Historic Preservation is a frequent burden for project sponsors because they are expected to resolve these inconsistencies through additional work and expense.

Importantly, all federal agencies are required to consider the impact of their actions on 81,706[1] listed

[1] Listed sites as of August 19, 2003. From the National Register of Historic Places website.

properties on the National Register of Historic Places. These properties were proposed, professionally evaluated through peer review, and added to the National Register only after each property was determined to meet NHPA criteria. This was, and is, the intent of the Act. Today, however, especially in the West, one out of every four cultural resource survey results in a "discovery" of pre-historic Native American or other historic features. These features are nearly always considered potentially eligible historic properties under one or more of the Secretary's Standards and Guidelines criteria. It is important to note these potentially eligible discoveries are afforded the same level of protection as National Register listed properties even though only a fraction of these sites is ever listed.

A Class III survey must be performed to determine if archaeological or historical resources are present and to consider the effects of the undertaking. Based upon the results of the Class III survey, the operator has several mitigating options that include:

- If no discoveries were made during the survey, no further action is necessary. Construction commences after all other APD requirements are fulfilled.
- Avoidance of discovered resources through project relocation. Avoidance is a very effective response to an identified concern.
- Funding by the operator for further studies to determine the significance of the discovered resource. This option frequently entails long delays to resolve issues concerning site significance, adequacy of mitigation requirements, and agency consensus on research design.
- Cancellation of the project due to the significance of the discovery and time and cost required to proceed.

Recommendations:

- Amend the NHPA to restore its original intent. Section 106 should be amended as follows:

  > Section 106. The head of any Federal agency having direct or indirect jurisdiction over a proposed Federal or federally assisted undertaking in any State and the head of any Federal department or independent agency having authority to license any undertaking shall, prior to the approval of the expenditure of any Federal funds on the undertaking or prior to the issuance of any license, as the case may be, take into account the effect of the undertaking on any district, site, building, structure, or object that is included in or eligible for inclusion in the National Register. The agency official may afford the Advisory Council on Historic Preservation established under Title II of this Act a reasonable opportunity to comment with regard to such undertaking.

  This change would allow agencies flexibility to determine when and if they need to consult with the Council. In 1966, virtually none of the Federal agencies had any professional archaeologists or historians. The Council and the National Park Service were the sole sources of expertise in these matters. Today, each agency has a staff of cultural resource professionals. For comparative purposes, the Council has approximately 37 employees nationwide, including administrative and clerical help, while BLM has over 150 archaeologists and historians throughout the agency. Other agencies are similarly staffed. These figures are augmented by consulting archaeologists and historians who are readily available to assist any and all Federal agencies.

- Section 211 of NHPA authorizes the Council to promulgate regulations for the implementation of Section 106 consultation procedures. That section should be deleted because there is no longer any reason for the Council to regulate how agencies comply with the National Historic Preservation Act. In defining the duties of the Council, Section 202 of the Act does not imply a regulatory role for the Council. The Council can instead issue guidelines as they contemplated in the September 15, 2000 notice in the Federal Register (see FR vol. 65, no. 180, and pp. 55928-55929). All federal agencies have internal regulations, procedures, manuals, and trained cultural resource staff to implement any and all aspects of the Act. That such agencies are qualified to manage cultural resources is demonstrated by the fact that less than one percent of all Section 106 consultations receive comments by the Council or SHPO.
- Steps need to be taken to ensure a more balanced viewpoint by the Council. Consideration should be given to representation by a larger number of Presidential appointees from rural America because these areas are the most heavily affected by the 106 process.

- Stipulation language attached to approved project permits issued by federal agencies for actions on public lands reads:

  > The operator shall be responsible for the cost of any mitigation required by the authorized officer. The authorized officer will provide technical and procedural guidelines for the conduct of mitigation. Upon verification from the authorized officer that the required mitigation has been completed, the operator shall be allowed to resume operations.

  Unfortunately, this language has been liberally interpreted in a manner that exceeds congressional intent, thereby penalizing operators by forcing them to perform exhaustive cultural resource studies far beyond the extent or scope of their projects. Such analysis and research is clearly the responsibility of federal agencies and should not become the sole responsibility of the operator, who may, however, voluntarily elect to cover a portion of the expense. The original intent for this language was to address discoveries during construction, e.g., when a pipeline trench is being excavated. Operators should only be responsible for site identification and location to facilitate further study by the agency. The condition of approval noted above should be rewritten as follows:

  > If archaeological, historical, or vertebrate fossil materials are discovered during construction, the operator shall suspend all operations that further disturb the discovered materials and immediately contact the authorized officer. The operator shall be responsible for the cost of locating a site by cadastral survey, and, in the absence of an agency archaeologist, for the cost of an authorized contract archaeologist to preliminarily identify the discovery. Operations shall not resume until written authorization to proceed is issued by the authorized officer.

- Establish statewide multi-agency cultural resource databases to catalog current information. Such a database would help eliminate or reduce the need for Class III surveys in areas that have little likelihood for occurrence of significant cultural resources. The database would reduce or eliminate duplication of previous surveys, and possibly highlight areas that need additional study and facilitate a shared vision of cooperation instead of conflict. Federal land managers and SHPO will benefit from a common database and reduced cost through improved allocation of resources and manpower.

- An independent review of agency practice and interpretation of criteria for determining site significance is critically needed. Criterion "D" of the Secretary's Standards and Guidelines is being used to extend potential eligibility to common sites when comparable sites are known to be locally prevalent. As a result of this practice, some BLM offices are finding up to 30% of all discoveries as potentially eligible for listing on the National Register of Historic Places when the actual likelihood is near zero. In addition, some SHPOs frequently concur with these "assessments" as a way to protect "significant cultural resources" that are perceived to be at risk from future oil and gas development.

- BLM and SHPO need to continue to streamline the cultural resource report review process. BLM must become proactive in expediting SHPO responses in accordance with the agency's protocol agreements, for example, the agreement in Colorado where BLM and SHPO share a joint database is a good model.

- Guidance for contract archeologists should be reviewed to ensure consistency and clarity, thereby promoting expeditious review and recordation of cultural resource reports.

- Timely and effective fulfillment of Native American government to government consultation and coordination under Sections 106 and 110 of the NHPA is an important area of concern for federal land managers and industry. It is imperative that agencies take immediate steps to assure consultation with Tribes is conducted by line managers rather than leaving such critical coordination to cultural staff. Government to government consultation requires a balanced viewpoint that is not always shared by individual program specialists. Consultation with Tribes is highly recommended at two stages, first, during planning when broad issues of Tribal concern can be addressed, and, when Section 106 cultural resource surveys result in discoveries of Native American origin.

- Under existing policy and practice, BLM makes oil and gas leasing decisions in its Resource Management Plan/Record of Decisions and defers Section 106 consultation until actual undertakings occur. Industry supports in the strongest terms, the continuation of this practice. The BLM should not impose duplicative consultation during planning and again when lease sales are contemplated.

Statute(s) and Regulations: The National Historic and Preservation Act of 1966 as amended, 36 CFR Part 800 Protection of Historical and Cultural Properties, 43 CFR Subtitle A Part 7 Protection of Archaeological Properties, 43 CFR Part 10 Native American Graves Protection and Repatriation Act, American Indian Religious Freedom Act of 1991, BLM Guidance for Native American Consultation, Wyoming BLM Cultural Resource Inventory and Evaluation Handbook.

C. Cumulative Effects Analysis and Post-Plan Monitoring

1. Cumulative Effects Analysis

Issue: During the land use planning and project permitting processes, both BLM and the Forest Service are required to prepare a Reasonably Foreseeable Development Scenario (RFDS) that is used to predict impacts associated with future oil and gas development. Land management agencies rely on geological information, production records, and historical drilling activity to develop RFDS, which is an estimate of the number of wells that ***might*** be drilled in the planning area over the life of the land use plan or project. Estimates are made of potential surface disturbance acreage, based on averages associated with well pad, access road, pipeline, and facility disturbances. Of concern, instead of using the RFDS as a planning tool, agencies use the RFDS to set surface disturbance ***limitations***, thereby ignoring the fact that properly plugged and reclaimed wells have no adverse effect on the environment or that technological advances have been made that significantly reduce project footprints and other concerns such as air emissions.

Impact: Use of the RFDS to evaluate environmental consequences for land use planning purposes is appropriate and encouraged; however, RFDS should not be used to establish surface disturbance limitations. By only focusing on well counts, the effectiveness of widely used and highly successful reclamation techniques and the compatibility of exploration and production activities with other multiple uses are ignored. The well count metric is ineffective and inflexible for meeting the needs of land managers and producers, and is inconsistent with sound science land management principles. The key element that must be considered in determining the level of oil and gas activity is not the number of wells which could be drilled, but rather the net effects of surface disturbance and reclamation coupled with identified levels of change.

Recommendation: Since the RFDS is simply an analytical tool, it is inappropriate to use it to establish a threshold or put a ceiling on future exploration or development. As such, it is essential for BLM and the USFS to adopt the concept of net effects because it relies upon active monitoring and sound science to establish suitable levels and patterns of use – in other words, it is the essence of land management. Moreover, the net effects approach will help facilitate more responsive and flexible land management while encouraging better environmental and public lands stewardship.

2. Monitoring of Land Use Plan and Project Implementation

Monitoring requirements are addressed in all BLM and Forest Service land use plans, but they are not given much priority with respect to land use plan or project implementation. While it is recognized that agencies are required to conduct certain monitoring activities under the Federal Land Policy and Management Act (FLPMA) and the National Forest Management Act (NFMA), neither agency has performed monitoring except for a few site-specific situations. Therefore, in addition to proposing a method for basing land use decisions on net effects and acceptable levels of change, it is essential for federal land management agencies to adopt a means for determining when land use activities are approaching identified levels of concern. To this end, monitoring must be performed for all resource activities, including motorized and non-motorized recreation, threatened and endangered species and their habitats, wilderness use, grazing, mining, wildlife, vegetation management, air and water quality, as well as oil and gas, to attain a realistic understanding of cumulative and net effects. When new development proposals are received, it is important for agencies to avoid decisions that halt all activity pending completion of new environmental impact statement(s) and plan revision(s).

Recommendation: To ensure a viable and responsible federal oil and gas program, it is critical that agencies establish monitoring as a priority in high activity areas. Focused monitoring will allow agencies to acquire important and current information applicable for short or long-term management objectives. For example, as levels of concern are approached, it would be possible for agencies and project proponents to develop mutually acceptable response measures that mitigate or reduce potential effects to acceptable levels. Similarly, the effectiveness of mitigation measures and conditions of approval can be tested and revised as necessary.

- It is incumbent on land management agencies to develop and fully fund a system for tracking monitoring efforts and reporting results.

- A quality control/quality assurance process must be established to ensure resource management objectives and acceptable levels of change are clearly stated and measurable.

- Measurable management objectives, which when exceeded require a review of existing management practices, must be clearly identified in land use plans and project-level NEPA documentation.

  An extremely important element of the monitoring effort is an inventory of resource data. Components of this database, which should be captured in Geographic Information Systems, would include:

- Inventories of resource activities, including oil and gas wells, fields, roads, pipelines, recreation use, grazing, wildlife populations, wildlife habitat condition and trend, etc., on state and federal lands

- Annual surveys of companies regarding future activities (BLM and the Forest Service must devise methods for protecting confidential information) to facilitate timely permitting and development

- Annual inventories of current surface disturbance and post-development reclamation for all resource uses to help determine net effects

- Capturing cultural resource and other surveys such as those for big game and threatened and endangered species

- Reviews of project-specific mitigation measures and conditions of approval to determine their need and effectiveness

- Capturing findings and learnings from project-related environmental analyses, and monitoring of land use plan and project implementation

- Reviews of the effectiveness of plan decisions, lease stipulations and conditions of approval.

D. Proposed Additions to the Threatened and Endangered Species List

Issue: Citizen nominations for additions to the list of species protected under the Endangered Species Act (ESA) pose challenges for agencies and lessees. To be clear, the problem is *not* protection of currently listed threatened (276) or endangered (986) species.[2] Rather, the problem is that because there are no qualification requirements to nominate a species for listing, any group or individual can file a petition to list without supporting scientific data. The lack of qualifications has led to species being proposed for the express purpose of procuring ESA as a tool to hinder land management planning and project permitting. All protective measures authorized by ESA apply to proposed species and their habitats. Once listed, species are rarely removed.

Impact: Agencies have 90 days to determine whether substantial information exists to indicate the proposed listing may be warranted. Due to the short timeframe and the usual lack of detailed species information, agencies treat *proposed* and *candidate* species as if they *are* listed, before fulfilling the ESA's specific requirements for species status, distribution and habitat information. As a result, environmental analysis of proposed projects becomes more complex, costly and prone to additional delay given the sheer number of proposed (37) and candidate (257) species.[3] The ESA applies to all lands regardless of ownership. The open-ended nomination process has several other significant, negative impacts:

- Uncertainty and risk is created for lessees, states, private landowners and land management agencies with respect to lease and property rights as well as project permitting requirements.

- Cost, complexity and delay are increased for land use plan preparation and project-level environmental analysis.

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2 Figures as of March 2003 from the U.S. Fish and Wildlife Service website.

3 Figures as of March 2003 from the U.S. Fish and Wildlife Service website.

- The importance of identifying species that deserve protection under the ESA from those that do not is lost, resulting in needless effort and waste of federal and taxpayer resources.

In addition to the federal list of protected species, individual states have extensive lists of sensitive species (e.g., Uinta-Piceance Basin has 272 species) that are identified by state wildlife agencies to be at risk of becoming endangered, extinct or warrants further research. Projects are subject to additional regulations that may impose new access restrictions and mitigation at the discretion of the state regulatory agencies.

Recommendations: The oil and gas industry believes that the ESA is not achieving its objectives; that proposed additions are made without benefit of sound science and that it is inflexible and fails to balance biological and economic concerns. Industry urges Congress to consider the following statutory amendments to ESA:

- Scope of Protection
  - Prohibit imposition of the same level of protection for candidate, sensitive and proposed species that is afforded listed threatened and endangered species.
- Public Participation
  - Require public hearings on proposed listings in all areas of the nation that would be affected. Require agencies to provide response summaries for the public.
- Listing and Designation of Critical Habitat
  - Require listing and critical habitat decisions to be based on the best *available* scientific and commercial information.
  - Develop specific criteria for what constitutes best available data.
  - Require independent scientific peer review of proposed listings and designations of critical habitat by a non-governmental panel.
  - Require preparation of a socio-economic impact analysis prior to listing and designation of critical habitat; and develop standards and criteria for determining whether listing certain species is in the national interest and disclosing countervailing economic and social impacts.
  - Streamline the de-listing process to emphasize the importance of removing recovered species from the endangered species list.
- Judicial Review
  - Allow affected parties to seek remedies in court to challenge listing and other ESA decisions.
  - Require parties opposing activities to demonstrate that immediate, irreparable harm to species will result from a proposed project before granting injunctive relief.
- Private Property Rights
  - Require compensation to private property owners in cases where significant loss of fair market value or other economic use of private property occurs as a result of ESA implementation.

Example: One well-known example is the northern spotted owl, which was listed as a threatened species in June 1990. According to the U.S. Forest Service's Pacific Research Station, the debate over the spotted owl started in the mid-1980s and was focused on management of old growth national forests in the Pacific Northwest. Today, the controversy over whether spotted owls prefer old growth forests continues but it is known most owl-occupied landscapes include diverse mixtures of old and young forest patches that are created by natural disturbances and timber harvesting. Because land managers have had difficulty developing a description of spotted owl habitat that can be applied over large areas, there is still considerable debate over how much habitat is available for spotted owls.

More is known about the spotted owl than any other owl in the world but the status of the species is still hotly debated. What is certain, however, is that surveying for and monitoring this species is a high priority on national forests in the Pacific Northwest. The ultimate objective of monitoring is to learn if national forest management plans and Habitat Conservation Plans like the one Weyerhaeuser developed for its 209,000-acre Millicoma Tree Farm near Coos Bay, Oregon will lead to viable spotted owl populations, but that may not be known for several decades.

Statutes and Regulations: Endangered Species Act of 1973 and implementing regulations at 50 CFR 1711 and 1712, and 50 CFR Part 402, Interagency Cooperation. Other statutes include the Marine Mammal Protection Act, the Migratory Bird Treaty Act, the Bald Eagle and Golden Eagle Protection Act.

Involved Agencies: principally U.S. Fish and Wildlife Service and National Marine Fisheries Service; however, other state and federal agencies can become engaged if projects occur on lands they administer.

E. Federal Land Use Planning (LUP)

Issue: Both the Bureau of Land Management (BLM) and the U.S. Forest Service (USFS) are required to prepare land management plans for lands under their jurisdiction.[4,5] Land use plans are the principal tool used by agencies to allocate uses of the public lands and to protect and manage resources. In preparing LUPs, agencies are required to comply with several key statutes, e.g., the Multiple Use Sustained Yield Act of 1960, Resources Planning Act (RPA), National Forest Management Act (NFMA), Federal Land Policy and Management Act (FLPMA), and the National Environmental Policy Act of 1969 (NEPA). Scientific analyses, as well as opportunities for public involvement, are integral elements of the LUP process. The LUP process, as currently implemented by BLM and USFS, has impeded oil and gas development on public lands in the following ways:

- Backlog of LUP revisions and associated delays
- Lack of Leasing decisions
- Biased cumulative effects analyses
- Lack of post-plan monitoring
- Inadequate BLM and USFS minerals staff.

1. Forest Service

There are 155 national forests and 20 national grasslands within the National Forest System covering 191 million acres. In the 1980s, the U.S. Forest Service (USFS) incorporated oil and gas leasing decisions as part of the planning process as evidenced, for example, by language in the 1987 Record of Decision (ROD)[6] for the Custer National Forest Land and Resource Management Plan (LRMP). Soon after the plans were completed, however, scores of appeals and legal challenges were filed by non-governmental organizations (NGOs). In an effort to avoid such challenges, the agency retreated from its original position, claiming it had not, after all, made any leasing decisions. Rather, the USFS declared that LRMPs merely establish a broad programmatic view of how oil and gas exploration and development may be managed. Hence, approximately 30 additional oil and gas leasing environmental impact statements and RODs were prepared nationwide.

With the implementation of the Federal Onshore Oil and Gas Leasing Reform Act of 1987 (FOOGLRA), the USFS further confused the leasing program by adopting a two-step process for leasing. The regulations at 36 CFR 228 Part 102 (d) determine the lands administratively available for leasing, and 102 (e) authorizes leasing decisions for specific lands. As a result, agency policy has been to make the leasing availability decision in LRMPs but to defer making the specific lands decision until a separate leasing EIS is completed.

An additional issue concerns the agency's December 2002 proposed planning rule at 36 CFR 219. In an effort to allow planning activities to proceed without appeal, the Forest Service decided that no leasing decisions will be made at the programmatic stage and that all subsequent activities will require separate NEPA analysis and decisions.

Impact: In addition to growing agency resistance to leasing Forest lands, the USFS' planning process became even more onerous in recent years. Besides increasing restrictions for wildlife and other concerns in areas where leases are being processed, in 1997 the forest supervisor for the Lewis and Clark National Forest refused to lease lands in the Montana Overthrust Belt despite the fact that the leasing EIS did not support a "no leasing" decision. This unwillingness to make oil and gas leasing decisions has spread to the

[4] Enabling legislation: Federal Land Policy and Management Act of 1976, §202 – Land Use Planning.

[5] Enabling legislation: Forest and Rangeland Renewable Resources Planning Act of 1974 as amended by the National Forest Management Act of 1976.

[6] As evidenced on page 9 of the ROD issued for Custer National Forest LRMP in 1987, which states: "*I [forest supervisor] have identified the lands available for oil and gas leasing, lands available for leasing with No Surface Occupancy stipulations, and lands that I have identified where conditions lead to recommendations not to lease.*"

Bridger-Teton National Forest in Wyoming where that forest supervisor also refused to make leasing decisions, even though the Forest spent several years preparing a leasing EIS. Other forests are now seeking ways to avoid leasing on USFS lands.

2. BLM

The BLM manages 262 million acres of public land, located primarily in the 12 Western States, including Alaska, and 700 million acres of federal mineral estate. BLM prepared 162 resource management plans during the first round of planning which came to a close in the early 1990s. In 1986, BLM developed planning guidance for fluid minerals which was incorporated into the agency's 1624 Manual. Specifically, BLM is required to ascertain post-lease impacts that could occur after oil and gas lease issuance. To do this, BLM relies on historical drilling activity to develop a reasonably foreseeable development scenario (RFDS), which is then used to identify management objectives, including mitigation measures and limits on future oil and gas activities, for each management alternative. Unfortunately, instead of limiting use of the RFDS to consideration of environmental consequences, BLM uses the *number of wells* identified for each RFDS to set surface disturbance limitations. By doing so, BLM ignores the fact that properly plugged and reclaimed wells have no adverse effect on the environment. In addition, BLM has done an ineffective job of monitoring land use plan and project implementation. As a result, similar to the USFS, ever-escalating restrictions are imposed on lessees, through lease stipulations, project-related conditions of approval (COAs), and LUP revisions. Few of these restrictions are scientifically justified or have been shown to facilitate desired outcomes.

In 2001 BLM began to update its resource management plans and is expected to complete the process over the next 10 years. BLM identified 21 Time Sensitive Plans, 9 of which are in areas that are highly prospective for natural gas.

Impact: Resolution of issues regarding BLM's use of RFDS to establish surface disturbance limitations, adoption of net effects and increasing monitoring priorities are crucial to orderly resource development and land use planning. For example, in 1991, a new oil discovery utilizing horizontal drilling technology was made in Utah BLM's Grand Resource Area. Because BLM had an RFDS of 10 wells for the area, companies were limited to drilling 10 wells to define the structure. This expectation became impossible when 7 of the 10 wells were dry holes which were plugged, abandoned and reclaimed. Rather than acknowledging the fact that the surface disturbance was reclaimed, BLM focused only on the 10-well limitation and insisted that a LUP amendment (at industry expense) was needed to allow more than 10 wells. Because most of the wells were dry holes, industry was unable to justify funding such an analysis. Of note, if the analysis had been done, it would only have been used to update the Grand RMP rather than to approve pending wells or projects. Today, no new wells can be drilled, and industry has no means of evaluating resources in the area because BLM has yet to amend its LUP to accommodate additional drilling. This example is not unique to the Grand Resource Area; it extends to almost all federal lands with significant potential for oil and gas development.

Recommendations: The federal land management planning process must be refocused to demonstrate the agencies' commitment to a viable oil and gas leasing program on both BLM and National Forest System lands in accordance with the President's National Energy Policy as described in Executive Orders 13211 and 13212. This can only be accomplished by:

- Allowing use of Categorical Exclusions for sundry notices and Applications for Permits to Drill on multiple-well pads.
- Developing LUPs that ensure leasing and development of natural gas resources located on BLM and USFS lands and recognizing that reasonable lease stipulations are essential, particularly in known high potential areas such as the Wyoming and Montana Overthrust Belts.
- Establishing monitoring as a priority to track land use plan and project implementation. A system for tracking and coordinating monitoring within and among agencies needs to be developed, along with improvements in coordination among agencies for data exchange and research.
- Strengthening the process by which relevant or new information from inventory, monitoring, and research activities is incorporated in LUP revisions and project-specific NEPA documentation.
- Provision by Congress of adequate and stable funding.

- Eliminating duplicative NEPA analyses and requiring use of sound science principles to justify lease stipulations and conditions of approval in planning and permitting documents.

- Using RFDS as a planning tool and refraining from using them to establish surface disturbance limitations.

- Incorporating "net effects" in the RFD and land use planning processes. Agencies should recognize:

  – That more wells can be drilled in many areas without exceeding surface disturbance levels established in LUPs.

  – Wildlife habitat values associated with restored well sites, construction staging areas, roads, and other facilities that are no longer in use. Restored acreage should be excluded from surface disturbance calculations.

- Making science-based determinations about the efficacy of lease stipulations and conditions of approval.

- Maximizing land use planning and cost efficiencies by including both the 36 CFR 228 Part 102 (d) & (e) leasing decisions in USFS LUPs.

- Ensuring there are adequate BLM and Forest Service minerals personnel with the requisite expertise required to implement LUP directives and facilitate leasing decisions and project permitting.

F. Forest Service Roadless Rule (36 CFR § 294.13)

Issue: Nearly 35 million acres on the National Forest System have been designated wilderness by Congress since 1964. In January 2001, the Clinton Administration issued a final rule that would prohibit all road construction and reconstruction on an additional 58.5 million acres of inventoried roadless areas throughout the National Forest System, except for health and safety reasons, essentially creating "de facto" wilderness. In addition, the Forest Service was directed to evaluate smaller uninventoried areas to assess whether they too warrant special protection.

Impact: Administrative and statutory withdrawals from oil and gas exploration and development on the National Forest System would jump from 22% (wilderness) to over 50% upon implementation of the Roadless Rule. Further, approximately 9.4 trillion cubic feet out of a total of 11.3 trillion cubic feet of natural gas would be withdrawn from development.[7] Significantly, 14% of the Inventoried Roadless Areas (IRAs) in the Rocky Mountain region contain 83% of the nation's natural gas resources located in the IRAs. Importantly, these high gas potential areas represent less than 5% of the national IRA acreage. Recovery of these potentially foregone resources would generate from $23 to $34 billion of economic activity.[8] Clearly, the roadless rule has severe impacts to rural and western state economies through significantly decreased access to Forest Service Lands for natural gas exploration and development, grazing, timber harvest, along with a host of other multiple-use activities.

Given the scope of the proposal, an EIS was prepared by the Forest Service addressing the impacts of the proposed rule which was to go into effect on May 12, 2001. However, the State of Idaho sued to enjoin implementation of the Roadless Rule for violating NEPA, the National Forest Management Act (NFMA) and the Administrative Procedures Act (APA), and requested declaratory judgment. The court found that plaintiffs were likely to succeed on charges that the public was given an inadequate opportunity to comment on the proposed rule, that there was inadequate identification of roadless areas, an inadequate range of alternatives, and that the agency failed to analyze the negative impacts of the alternatives it did study. While the Bush Administration did not defend the rule, it asked the court to reserve its ruling to provide the administration time to submit a status report on its review and findings. Despite the administration's announcement that additional measures would be taken to address reasonable concerns raised, the judge granted a preliminary injunction on May 10, 2001 to prevent implementation of the Roadless Rule and the portion of the Planning rule that relates to roadless areas. The ruling was appealed by intervenors in the case to the 9th Circuit Court of Appeals, which remanded the decision

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7 Advanced Resources International, Inc., *Undiscovered Natural Gas and Petroleum Resources Beneath Inventoried Roadless and Special Designated Areas on Forest Service Lands Analysis and Results*, 11/20/2000, prepared for the Department of Energy.

8 Advanced Resources International, Inc., *Economically Recoverable Natural Gas Resources Beneath Inventoried Roadless Areas on Forest Service Lands, Analysis and Results*, 11/30/2000, prepared for the Department of Energy.

back to the lower court for review. The Ninth Circuit court denied the petition for rehearing and vacated the preliminary injunction.

The State of Wyoming also filed suit in the Tenth Circuit of Federal District Court seeking to block implementation of the Roadless Rule. On July 14, 2003, the U.S. District Court of Wyoming issued a permanent injunction thwarting execution of the Roadless Rule on the grounds that it constitutes an attempt to administratively designate more than 58.5 million acres of "de facto" wilderness when only Congress has authority to designate wilderness. In addition to violating the 1964 Wilderness Act, the court found the rule violated the National Environmental Policy Act. As of this writing, special interest groups have filed a notice of intent to appeal the ruling in the Tenth U.S. Circuit Court of Appeals.

Recommendations: It is critical for the U.S. Forest Service to comply with Congressional direction stated in the Multiple Use and Sustained Yield Act. Title 16, Chapter 2, Subchapter 1, §528. – Development and administration of renewable surface resources for multiple use and sustained yield of products and services; Congressional declaration of policy and purpose, states:

> It is the policy of the Congress that the national forests are established and shall be administered for outdoor recreation, range, timber, watershed, and wildlife and fish purposes...**Nothing herein shall be construed so as to affect the use or administration of the mineral resources of national forest lands** or to affect the use or administration of Federal lands not within national forests. [emphasis added]

Implementing the following two recommendations would allow the Forest Service to comply with the Multiple Use and Sustained Yield Act without compromising its interest in protecting IRAs while making valuable lands available for leasing to help meet projected increases in gas demand over the next 20 years.

- Eliminate IRAs that contain natural gas resources. These areas comprise less than 5% of the areas included in the Roadless Rule:
  - Montana Thrust Belt
  - Wyoming Thrust Belt
  - Uinta-Piceance Basin
  - Southwestern Wyoming.
- Modify the Roadless Rule to exempt all roads associated with oil and gas exploration and development activities because they are temporary in nature, subject to extensive environmental regulation and typically are fully reclaimed after production ceases.

Statutes and Regulations: Multiple-Use Sustained-Yield Act of 1960, Mineral Leasing Act of 1920, as amended, Energy Security Act, Federal Land Policy and Management Act of 1976, National Forest Management Act of 1976, Resources Planning Act.

G. BLM Wilderness Re-Inventories/ Citizens Wilderness Proposals in Utah and Colorado

Issue: Section 603 of the Federal Land Policy and Management Act of 1976 (FLPMA) directs the Department of Interior (DOI) to identify lands eligible for inclusion in the National Wilderness Preservation System (NWPS) established by the Wilderness Act of 1964. Between 1977 and 1980, BLM inventoried *all* public lands in two phases which resulted in identification of over 700 Wilderness Study Areas (WSAs) totaling about 26.5 million acres in eleven western states.

Immediately after DOI's wilderness recommendations were submitted to Congress in 1993, wilderness advocates began criticizing BLM for excluding "eligible areas" even though they did not appeal most of these "omissions" in 1980. Soon after, citizen wilderness bills surfaced, urging congressional protection for millions of acres BLM had determined did not qualify for wilderness consideration, much less designation. Citizen wilderness proposals range in size from individual areas to multi-state proposals such as the Northern Rockies Ecosystem Protection Act, which would have designated over 20 million acres of federal lands as wilderness in parts of Montana, Idaho, Wyoming, Oregon, and Washington, as well as over 1,800 miles of new Wild and Scenic Rivers. In a sympathetic move, then Secretary of Interior Babbitt issued a policy that allowed nominated areas to be held in limbo in perpetuity such that no economic use, including leasing, can occur on these lands.

Impacts: Because citizens' wilderness proposals and BLM wilderness re-inventories typically remove hundreds of thousands to millions of acres of public land from leasing and other multiple uses, significant economic challenges are created for gas resource and rural economic development, and to state and federal treasuries. Many areas located in the Uinta and Piceance Basins are being managed as WSAs, either by BLM re-inventories or through Utah- and Colorado-citizen proposed wilderness bills. Although potential exists for similar citizen wilderness bills to be introduced for other western states, complementary BLM wilderness re-inventories are not expected under the current administration. WSAs and wilderness re-inventoried areas are subject to BLM's Interim Management Policy (IMP), which requires protection of wilderness values until Congress either designates them as wilderness or returns these areas to multiple-use.

Utah: The Utah wilderness debate has a particularly contentious history. After ten years of studying 3.3 million acres as WSAs, BLM recommended 1.9 million acres as suitable for wilderness in 69 areas. Wilderness advocates countered with America's Red Rock Wilderness Act of 1997 (HR 1500), which would designate over 9 million acres of wilderness in Utah. Of strong concern to multiple users, HR 1500 generally ignored wilderness eligibility criteria established in the 1964 Wilderness Act by including roads, homes and portions of towns in the bill and was introduced without consulting the Utah Congressional delegation, which unconditionally opposed the bill. HR 1500 has been reintroduced in successive congressional sessions. Meanwhile, after years of public and county consultation, Utah's congressional delegation attempted a more reasonable proposal (Utah Public Lands Management Act) that would have designated 3.1 million acres but environmental groups and the Clinton Administration rejected this bill.[9] Subsequently, Rep. Hansen (R-UT) introduced HR 3035 (Utah National Parks and Public Lands Wilderness Act) that would designate 2.4 million acres but this bill only escalated the debate.

In 1996, Interior Secretary Babbitt, citing more than 20 years of wilderness debate, directed BLM to re-inventory 3.1 million acres that had been excluded from wilderness study by the agency's original wilderness inventory. Many of the areas identified in HR 1500 and HR 1745 served as the basis for the re-inventory. To justify the re-inventory, the Secretary of Interior cited authority at Section 201 of FLPMA, which directs:

> The Secretary shall prepare and maintain on a continuing basis an inventory of all public lands and their resources and other values (including, but not limited to, outdoor recreation and scenic values), giving priority to areas of critical environmental concern. This inventory shall be kept current so as to reflect changes in conditions and to identify new and emerging resource and other values.

The State of Utah challenged BLM's wilderness re-inventory, arguing DOI's authority had expired under FLPMA's 1991 deadline, by which the agency's wilderness recommendations had to be submitted to the President. However, the U.S. Tenth Circuit Court of Appeals found the Secretary did have authority to conduct an inventory. Specifically, Section 202 (a) of FLPMA states, "the preparation and maintenance of such an inventory or the identification of such areas shall not, of itself, change or prevent change of the management or use of pubic lands." While the Tenth Circuit Court of Appeals rejected the legal challenge to the re-inventory, it remanded the issue of DOI's imposition of a "de facto" wilderness management standard on non-WSA public lands in Utah to the District Court. The case was settled in April 2003 when DOI agreed to rescind all re-inventory management direction and not pursue designation of new WSAs.

Colorado: DOI's refusal to issue leases in citizen-proposed wilderness areas became an issue in Colorado in 1994 when the BLM State Director made a commitment to the Colorado Environmental Coalition (CEC) not to lease areas within CEC wilderness proposals. In nearly all cases, these lands were identified by BLM as wilderness inventory units but were dropped from consideration as WSAs because their attributes did not meet BLM's WSA criteria. The CEC Wilderness Proposal totals 1.6 million acres, consisting of 650,000 acres that were excluded from wilderness study during the inventory process, all pending WSAs (nearly 800,000 acres) and other acreage. No public involvement or notification was provided by BLM before deciding to withhold leasing on CEC nominated lands, further, this decision contravenes current management direction in BLM RMPs which show these lands to be available for leasing.

9 At a 1999 House Resources Subcommittee on National Parks, Lands and Forests hearing on the bill, a Deputy Assistant Secretary of Interior testified, "this bill is far off the mark. If the bill were presented to the President in its current form, Secretary Babbitt would recommend that he veto it."

Colorado BLM was forced to justify its "no lease" agreement in 1996 after inadvertently posting and then pulling a lease parcel located in one of the CEC proposed wilderness areas. With assistance from the Department of Interior, Colorado BLM developed a new procedure that sets aside all 650,000 acres that were inventoried by BLM but released from WSA consideration until a plan amendment is completed. Many Colorado counties objected, as did the oil and gas industry, but were unsuccessful. The revised procedure, Processing Actions Proposed in the Remaining Areas in the Conservationists' Wilderness Proposal (Instruction Memoranda CO-97-044, CO-98-017, CO-99-013 and CO-01-005), requires BLM to notify CEC of proposed actions within their nominated wilderness areas. In addition, BLM Field Offices are required to review pending actions for irreversible and irretrievable impacts before proceeding with the action and a plan amendment. While the policy requires plan amendments to be completed on 6 areas of current oil and gas lease interest, none have been initiated as of April 2003. Moreover, because the plan amendment process cannot commence in any of the other CEC proposed wilderness areas until an action is proposed, all 650,000 acres of CEC proposed wilderness have been managed as "de facto" wilderness since 1994.

Recommendations:

- Given the fact that the re-inventory process was instituted as a matter of policy, it seems it would be a simple matter for BLM to retract the entire process to be consistent with FLPMA §202. Language from this section limits BLM's authority to study and designate WSAs to the 15-year wilderness review period specified in §603 of FLPMA.

- Ample justification for the retraction exists. For example, the Interior Board of Land Appeals, which is Interior's administrative hearings and appeals review body, has routinely upheld this limitation on authority, that "final administrative decisions designating [WSAs] in Utah and excluding remaining lands from such areas were issued in the 1980's." *Southern Utah Wilderness Alliance,* 123 IBLA 13, 18 (1992); *Southern Utah Wilderness Alliance et al.,* 128 IBLA 52, 66 (1993); *Southern Utah Wilderness Alliance et al.,* 122 IBLA 17, 22 (1992).

Statute: Federal Land Policy and Management Act of 1976, §603.

H. Noise

Issue: Stationary noise from gas production operations may be an issue when activities ensue near raptor nests, recreation and visitor sites on public lands and rural communities. The extent to which noise is an issue is highly variable, and is dependent on the location and terrain where drilling and gas production occurs as well as the type of equipment that is used. There is no established BLM or Forest Service standard for noise at this time. Although some states and local municipalities have standards for noise, they vary from location to location. Noise, as perceived at an occupied home or other receptor, varies according to site-specific conditions such as wind, terrain, and temperature, as well as the sensitivity of individuals.

Impact: Stationary noise mitigation is an issue for operators because the need for and extent of mitigation is highly variable and the cost associated with noise reduction can be very high. In certain instances, the added cost of noise mitigation could force new projects to become subeconomic and may lead to premature abandonment of production. Mitigation options may include project relocation, changing engines, installing high performance mufflers, building sound walls of various configurations, or completely enclosing the source of noise in a building. The effectiveness of each option varies; in addition, whether an option is implemented may be dependent on other issues. For example, four-sided sound walls are effective in certain instances, but they create engine overheating, worker health and exposure issues, and safety challenges that limit their use.

The primary source of stationary noise typically results from internal combustion and turbine engines and associated equipment such as pumps and compressors. Noise from these sources can be from the exhaust, internal moving parts, the engine frame and cooling fans.

In June 1991 Argonne National Laboratory conducted a noise study on selected wildlife species. The report, "A Study Of The Effects of Gas Well Compressor Noise On Breeding Bird Populations Of The Rattlesnake Canyon Habitat Management Area, San Juan County, New Mexico, concluded that a 50 dB(A) standard would be protective of birds. Beyond this study, studies on noise and its effects on animals are limited.

Recommendations:

- Landowners, real estate companies and real estate buyers must be aware that the mineral rights under private property may already be under lease, or, be leased at some future date, and that drilling may occur and wells may be placed in production on private surface lands.

- It is important that agencies only consider noise standards that have a scientific basis and/or evaluate existing regulations that have an established record of implementation and have been shown to be effective for meeting local needs and conditions.

- Oil and gas producers should evaluate noise levels at nearby receptors. If noise is identified as an issue, operators should utilize applicable best practices and/or the mitigation measures noted above.

I. Protection of Designated National Historic Trails and Associated Viewsheds

Issue: The National Trails System Act was enacted in 1968 to provide for a national system of recreation, scenic and historic trails. Congressionally designated National Historic Trails recognize prominent past routes of exploration, migration, and military action. The National Park Service administers thousands of miles of trails across the country. These trails are located on lands under the jurisdiction of various federal land management agencies. The following criteria must be met to qualify for designation as a National Historic Trail:

- Be established by historic use and be historically significant as a result of that use.

- Be of national significance with respect to any of several broad facets of American history. To qualify as nationally significant, historic use of the trail must have had a far reaching effect on broad patterns of American culture.

- Have significant potential for public recreational use or historical interest based on historic interpretation and appreciation.

To be clear on the issue, the oil and gas industry supports recognition and protection of designated National Historic Trails and the elements associated with our nation's history if they are consistent with the criteria established by the National Trails System Act.

On January 18, 2001, President Clinton signed Executive Order 13195, "Trails for America in the 21st Century," that requires federal agencies to ensure trail corridors and trail values are protected. This Executive Order was the impetus for Wyoming BLM to develop Interim Guidance for Managing Surface-Disturbing Activities in the Vicinity of National Historic Trails (WY-2002-001). The Interim Guidance included protection of viewsheds associated with Congressionally designated trails and consideration of ***undesignated*** trail segments and sites that in the future ***may*** be considered for listing on the National Register of Historic Places.

Impact: Executive Order 13195 created two major problems for industry and the State of Wyoming associated with BLM's management of historic trails and protection of visual resources. The first is a conflict with current BLM Resource Management Plans (RMP) that require the "area within 1/4 mile of the trail or the visual horizon, ***whichever is less*** … to be an avoidance area for surface disturbing activities." Wyoming BLM's Interim Guidance proposed analysis of surface disturbing activities up to five miles on each side of certain trail segments, far beyond current RMP requirements.

The second major issue is protection of viewsheds that are also addressed by BLM through use of Visual Resource Management (VRM) stipulations. Because VRM guidelines are vague, implementation of visual protection stipulations is highly subjective and inconsistent throughout Wyoming, but these concerns pale in comparison to BLM's Interim Guidance requirements. Where trail segments are perceived to have high landscape values, the Interim Guidance proposes two management options: Deferral of prospective lease parcels from future lease sales until RMPs are modified or amended, or, suspension of affected leases until trails issues are resolved. Both options represent major departures from current practice and pose extreme adverse effects for lease sales and the ability to produce natural gas from leases located near historic trails.

Due to the adverse effects of the Interim Guidance to lessees, producers, and the State of Wyoming, BLM eventually withdrew the Interim Guidance and is currently developing a Trail Management Plan for Congressionally designated national historic trails. When completed, Wyoming's Trail Management Plan will be used to amend existing RMPs and is expected to become a model for other states. As such, industry has strong concern about potential impacts to gas development near historic trails in Wyoming and nationwide.

Of note, BLM has no requirements for the general public to obtain permits prior to use of or driving along trails, and, in most areas there are no off-road vehicle restrictions. Therefore, the public is free to utilize historic trails for recreation, hunting, and other purposes without any BLM intervention.

Recommendations:

- Land management agencies should not implement restrictive requirements for trails and associated viewsheds prior to consideration by Congress for their historical significance.

- Changes in trail management plans should not be implemented until a comprehensive NEPA analysis is completed and existing RMPs are properly amended.

- Accommodation of valid existing lease rights and disclosure of gas resources that may be lost due to trail and viewshed protection should be considered key issues in BLM's trail management plans.

- Disclose the socioeconomic impacts of historic trail and viewshed protection to lessees, current production activities, state and federal revenues, and local economies. Further, BLM should use a cost benefit analysis to quantify the impacts.

- Visual resource management guidelines must be used objectively and consistently to avoid unintended effects to private landowners, lessees and state and federal revenues.

Statutes and Regulations: National Trails System Act of 1968 as Amended through 1992; National Historic Preservation Act of 1966 as Amended through 1992; Secretary of Interior's Standards for the Treatment of Historic Properties with Guidelines for the Treatment of Cultural Landscapes; January 18, 2001 Executive Order "Trails for America in the 21st Century"; the 2001 Revised Code of Federal Regulations, 36 CFR 800, "Protection of Historic Properties"; and existing stipulations from BLM Resource Management Plans.

J. National Environmental Policy Act

Issue: The intent and expectations identified in the National Environmental Policy Act (NEPA) and Council on Environmental Quality (CEQ) regulations for a compact, clear and efficient environmental analysis and decision-making process have not been met in practice by the governing agencies. The manner by which land and resource management plans and environmental documentation for projects are developed has created public concern and distrust about the federal decisions being made. The NEPA process has become unnecessarily complex and cumbersome, and has greatly increased cost, delay and uncertainty for operators seeking onshore and offshore exploration, development and production opportunities.

Impact: Although NEPA only applies to federal agencies, the extent to which federal decisions are intertwined with state, local and private interests makes NEPA a universal issue for onshore and offshore producers. NEPA comes into play when land and resource management plans are developed or revised; during promulgation of new regulations or when existing regulations are revised; when five year plans for OCS leases are proposed; when oil and gas leases are offered by federal agencies; when permits are sought for new projects; and when existing operations are expanded or modified.

Enacted in 1969, NEPA is our basic charter for protection of the environment. NEPA is a procedural act, that, in conjunction with it's implementing regulations, was designed to ensure the federal government considers the environmental consequences of all major federal actions that significantly affect the human environment. NEPA established the environmental review process and created the Council on Environmental Quality (CEQ) within the Executive Office of the President. CEQ developed regulations that require public involvement throughout an extensive environmental analysis process that examines:

- The environmental impact of the proposed action,

- Any adverse effects which cannot be avoided,

- Alternatives to the proposed action,

- Relationships between local short-term uses and maintenance and enhancement of long-term productivity, and

- Any irreversible and irretrievable commitments of resources which would be involved if the proposal is implemented.

In general, industry believes NEPA has been successful in requiring federal agencies to take a hard look at the environmental consequences of their actions, bringing the public into the decision-making process, and reducing environmental effects through use of lower impact alternatives and mitigation measures. Industry does not believe changes are required to NEPA or the CEQ regulations, but urges senior land management agency officials to give serious attention to the NEPA implementation process to comport with original congressional intent. The following are a few examples that illustrate how the clear intent of NEPA and the plain language of the regulations are being abused. Relevant citations from CEQ regulations are shown in brackets where they apply:

- The detailed analysis required by NEPA has become an end unto itself instead of serving as a tool to improve federal agency decision-making. Agencies view NEPA as a compliance requirement instead of a process that leads to improved decision-making and public support. For example, although agencies commit to monitoring, only a few offices actually perform monitoring and acquire and incorporate new information after land and resource plans and projects are implemented. Monitoring may provide significant new information, for example, whether anticipated impacts to marine mammals occur, or, if required seasonal use stipulations are needed or effective. [§1502.2(a), EISs shall be analytic instead of encyclopedic, §1502.7, Page limits, and §1505.3 Implementing the decision.]

- Instead of preparing an EA and progressing to an EIS only after significant impacts are determined, agencies are pressing project proponents to prepare EISs at the outset in the mistaken belief that EISs are more "litigation-proof." Lessees are expected to pick up the added cost and live with the longer time required to complete an EIS. Similarly, EAs have grown in scope and magnitude such that they are nearly as extensive and require as many resources to complete as an EIS. [§1501.4, Whether to prepare an EIS]

- Consideration of alternatives to a proposed action has been reduced to a ***search*** for alternatives without regard for how unreasonable or infeasible those "alternatives" may be, or, whether there is any associated environmental or cost benefit. In nearly all cases, project sponsors are expected to pay for "research," ostensibly to determine the effects and mitigation of these infeasible alternatives. [§1502.14, Alternatives including the proposed action, §1502.16, Environmental consequences, §1502.23, Cost benefit analysis, and, §1502.24, Methodology and scientific accuracy.]

- Although federal agencies are only required to use the ***best available*** information, a widespread belief exists among agencies that current information (e.g., mule deer populations and habitat trends) in their possession (or residing with sister agencies), is inadequate, incomplete or unreliable. Federal agencies essentially force project sponsors to acquire new information through third party contractors before beginning analysis of the proposed project. [§1502.21, Incorporation by reference, also §1502.22 Incomplete or unavailable information.]

- CEQ requirements to ***disclose*** potential environmental effects and identify mitigation measures to reduce or eliminate anticipated effects are being interpreted by federal agencies to mean requiring use of "zero risk" alternatives, criteria and strategies, which results in the search for alternatives mentioned above. [§1502.22 Incomplete or unavailable information.]

- Although agencies claim form letter responses (e.g., postcards or mass emails) are "acknowledged," and deny counting public comment votes in favor of or against projects, it is clear that federal agencies are unduly influenced by public opinion and media attention even when their NEPA analyses and subsequent decisions meet legal, policy and environmental requirements. Recent actions to avoid approval of OCS development plans at Destin Dome, and denial of leasing in areas of known high potential on the Bridger-Teton and the Lewis and Clark national forests are referenced in this regard.

- Procedures for information exchange among state and federal agencies are still only informal 34 years after NEPA passed. Early and effective interagency coordination among state and federal agencies is critical for meeting NEPA requirements, public policy expectations, and natural resource management goals. [§1501.5, Lead agencies, §1501.6, Cooperating agencies and §1506.2, Elimination of duplication with State and local procedures.]

Inadequate staffing and funding at some BLM and USFS offices causes the process of completing development project EISs to become so time-consuming – often taking up to four years to complete – that many producers choose to bear the costs of completing these studies in order to speed up the process. Many potentially viable exploration projects have folded in the face of uncertainty created by the long delays and high costs related to NEPA compliance.

Finally, the practice of shifting NEPA compliance costs from agencies to lessees and operators is becoming routine, and is of strong concern among producers. In the past, operators would pay for surveys for cultural resources, threatened and endangered species or other biological resources on a voluntary basis to assist agencies and help expedite project timing. Today, operators are routinely expected to pay for the ***entire*** environmental analysis, and preparation of the NEPA document itself, ***including***, in some cases, financial support for land use plan updates such as the recently completed Powder River Basin Oil and Gas Final EIS in order to facilitate leasing, exploration and development activities.

The examples noted above clearly demonstrate the manner by which federal agencies implement the NEPA analysis is the single most significant impediment to recovery of onshore natural gas reserves, and is a significant impediment to exploration for and development of offshore gas resources. Significant streamlining and adequate funding of NEPA-related processes – both land management planning and the environmental analysis process for proposed projects – is vital to industry's ability to meet future U.S. natural gas demand.

Public Policy Recommendations:

- Federal agencies must use the NEPA process as a decision-making tool for federal land and resource managers and administration policy makers. NEPA should not be viewed as a requirement for agencies to develop litigation proof documents nor an opportunity for federal agencies to acquire new land and resource information at the expense of project sponsors.

- Steps need to be taken to ensure federal agency compliance with the clear intent and purpose of NEPA. Industry encourages the development of agency performance and accountability metrics to ensure better and more consistent compliance with NEPA and to inform the public and the Congress.

- Federal agencies need to integrate NEPA early in policy making and agency programs because it makes good economic and environmental sense – in other words, it is good government. Early integration will aid collection and use of critical data while eliminating duplication of data that is already available.

- Federal agencies need to establish monitoring as a high priority after implementation of land use plans and projects to ensure proper balance between resource protection and production. New information gained from monitoring can be used to ensure the use of appropriate conditions of approval and to reduce reliance on risk avoidance stipulations such as the No Surface Occupancy stipulation which is extensively used throughout the onshore leasing program. Active monitoring will help assist development of local, flexible, science-based land and resource management strategies.

- Agencies need to recognize technology-based tools are still being developed for impact modeling, estimating carrying capacity, assessing cumulative impacts, and testing the effectiveness of mitigation. There is no question progress using these tools will improve decision-making but the search for "better information" should not prolong project decisions. Uncertainty needs to be acknowledged, mitigation measures need to be identified and used, and agencies must fulfill commitments to monitor and adapt management tools as resource plans and projects are implemented.

- NEPA documents should present scientifically valid information and avoid speculation. NEPA documents should be written for the general public in a clear, concise and informative manner, highlighting the decision being made and the justification for that decision. Technical documents can be referenced or included in an appendix. More weight in the EA or EIS does not mean a more rigorous analysis has been performed.

K. Coal Bed Natural Gas Water Management

Issue: Production of coal bed natural gas (CBNG) has been recognized as an energy resource since the 1950s but has only gained commercial interest and momentum in recent years. While similar to conventional gas production, CBNG requires dewatering of coal seams to reduce hydrostatic pressure, after which the natural gas is released from the coal beds. The level of CBNG activity, coupled with the volume of produced water to be disposed of, have become issues in the Powder River Basin where it is uneconomical to re-inject produced water into underground formations. Concern has also been expressed about other water related issues such as possible shallow aquifer depletion, possible contamination of groundwater sources, possible adverse effects to streams and rivers, and possible migration of injected waters from approved injection zone(s).

Importantly, CBNG water volumes decrease rapidly as gas production ensues and the produced water varies in quality and quantity within and among coal basins. Two common options for managing produced water are surface discharge or injection into deeper zones. Selection of the water disposal method is dependent on variables that are unique to each project, such as basin geology (suitability of injection zones), soil types, topography, water quality, water quantity, cost, and land use. This complex mix of variables creates challenges and opportunities for producers and regulators that require creative, flexible, and project specific management approaches.

Impact: CBNG projects are being delayed due to the public's lack of familiarity with CBNG operations and the regulatory framework that is used to manage the resource. For example, concerns have been expressed about the viability of surface disposal and downhole injection options even though each option has been accepted and approved by state and federal regulators. Delays in the Powder River Basin were experienced due to land and resource management plan updates but these updates have now been completed.

When CBNG water is surface discharged, state agencies and/or the EPA are responsible for protecting water rights and water sources utilized for domestic supply, livestock, wildlife, agricultural and fisheries purposes. The responsible agencies are required to ensure all discharges that affect waters of the state and/or the U.S. meet federal Clean Water Act (CWA) regulations and state surface water classification standards. The mechanism to accomplish this goal is the National Pollutant Discharge Elimination System (NPDES) permit program. If a state has primacy, it has established its own requirements which may be more stringent than the federal CWA regulations. In all states, NPDES permits cannot be obtained if the water to be discharged does not meet defined, site-specific water quality standards.

Injection is a viable option for CBNG water management in certain basins. The Underground Injection Control (UIC) Program, administered by the EPA or state (if it has primacy), requires inspection, monitoring, sampling and record keeping to ensure underground sources for drinking water are protected. UIC regulations specifically provide for a category of oil and gas injection wells, known as Class II wells, which are used to dispose of fluids associated with oil and gas production. Class II well requirements include strict construction and materials specifications as well as periodic mechanical integrity testing of well casing and cement to prevent the movement of fluids in the wellbore. Monitoring, testing, record keeping, and reporting of the wellbore's mechanical integrity are all requirements of the Class II regulatory program.

Landowner involvement in evaluating options for disposal of produced water is an important aspect of CBNG development. For example, in the Powder River Basin, regulatory agencies require operators to develop Water Management Plans (WMPs) in consultation with landowners prior to commencement of operations. Aspects of WMPs may include landowner needs and requirements, water quality and volume, regulatory limits, soil types, land use both on location and downstream, local terrain, irrigation needs, and project economics. Because of the variability of water quality and land uses, WMPs vary substantially to meet local needs and conditions. In general, WMPs may use one or more of the following tools: re-infiltration, stock ponds, irrigation, surface discharge, atomization/evaporation, water treatment, soil amendments, and injection wells.

Recommendations:

- Governing agencies must maintain regulatory flexibility to maximize beneficial use of water
- Maintain flexibility in agency oversight of water management plans to accommodate specific needs of landowners and CBNG producers
- Support appropriate technological research (including peer reviews) to develop viable water management options
- Develop financial incentives for producers and landowners that encourage water management innovation
- Facilitate CBNG dialogue and education about the regulatory framework among landowners, producers, state and federal agencies, and the business community

- Improve the permitting process to reduce cycle time and increase predictability
- Improve coordination among state and federal agencies and eliminate overlaps in the processes.

Statutes:

1. Federal Clean Water Act

2. State Statutes (i.e. Montana Water Quality Act)

3. Federal Safe Water Drinking Act

Regulatory Agencies for Permitting and Compliance:

1. State Engineers Offices

2. State Departments of Environmental Quality under primacy granted by the Federal Environmental Protection Agency and as directed by state statute

3. Corps of Engineers

4. Oil & Gas Conservation Commissions

5. BLM

6. Environmental Protection Agency

Other Sources of Information: United States Environmental Protection Agency, 2002. Protecting Drinking Water Through Underground Injection Control, Office of Ground Water and Drinking Water (4606-M), EPA 816-K-02-001.

III: Offshore Public Policy Recommendations

A. Access to OCS Resources

Issue Description: The majority of submerged lands located offshore the continental United States are unavailable for oil and gas leasing and development. Most of the acreage that is available for leasing is located in the western and central portions of the Gulf of Mexico off the coasts of Texas, Louisiana, Mississippi, and Alabama. Ninety eight percent (98%) of the leasing and drilling activities in federal offshore waters are concentrated in the Gulf of Mexico.

Issue Impact: In the United States, approximately 20 million barrels of oil per day and more than 57 billion cubic feet of natural gas per day is consumed. Domestic oil fields provide about 42% (8.4 million barrels of oil per day) of the nation's oil and 85% (48.45 billion cubic feet of natural gas per day) of the nation's gas. The remaining 58% of oil and 15% of natural gas are imported from different sources from around the world.

Approximately 26% of domestic daily natural gas is produced from the Outer Continental Shelf (OCS). The majority of this gas comes from the western and central portions of the Gulf of Mexico from wells located in water depths less than 1,000 feet. Wells located in deepwater (greater than 1,000 feet) are beginning to contribute to the daily production volumes from the Gulf of Mexico OCS.

The OCS program generates approximately $6 billion in revenues to the government each year. The Minerals Management Service (MMS) collects and distributes these revenues to special purpose funds administered by various federal agencies, States, and to the General Fund of the U.S. Department of the Treasury. Each year $150 million of offshore revenues are transferred to the National Historic Preservation Fund. The OCS provides over 90% of revenues to Land and Water Conservation Fund. Since 1990, it has provided more than 95% of the LWCF every year. In addition, OCS revenues contribute 70% to 90% of the legislated yearly minimum $900 million allocated to fund the Land and Water Conservation Fund. The coastal States receive 27% of OCS revenues generated from leasing of lands within three miles of the seaward boundary of a coastal State's boundary. In the Gulf of Mexico, off the coast of California and in Alaska, these payments are substantial each year. Offshore revenues are a significant source of income for both the States and federal governments.

Recommendation for Improvement: Without retraction of the existing Presidential Executive Order which established a leasing moratoria over most of the OCS, or changes in the interest level of many planning areas in Alaska currently not available for leasing due to administrative deferrals, no additional offshore acreage will be offered for leasing beyond what is covered in the 2002-2007 5-year leasing program at least until June of 2012. If the current policies of the federal government are not modified to allow access to areas currently off limits to oil and gas exploration and development, it can only be assumed the current acreage in the 5-year plan will be the only acreage potentially available for OCS leasing and development through 2012.

B. Coastal Zone Management (CZM)

Issue Description: The CZM Act was passed in 1972, after the Stratton Commission Report, to create a framework within which States would be motivated to act within their Constitutional powers to promote "the effective management, beneficial use, protection and development of the coastal zone."

There are several incentives for states to create CZM programs and have them approved by the Secretary of Commerce. Federal aid is provided to assist in planning, coordination and funding of program components designed by each state to achieve that state's goals. A major incentive, however, has been the power states with approved CZM programs are given over direct and indirect actions of the federal government and its agencies. It is through this provision of the Act that offshore oil and gas activities, pipeline transportation of hydrocarbon energy sources and the development of alternative sources of energy like wind power can be subjected to state control. Conflicts have arisen between the Commerce Department's administration of the CZMA and the MMS's implementation of the energy goals of the Outer Continental Shelf Lands Act (OCSLA). This can happen even where only one of several affected coastal states disapproves of the proposed activity.

Issue Impact: As the law is now being administered, those who wish to stop activities do not have to demonstrate actual adverse impacts on state interests in order to subject proposed offshore projects to delay, uncertainty and disapproval. States can impact leasing, exploration and production activities on the OCS off the shores of other affected coastal states which approve of those activities. In addition, the citizen suit provisions of the CZMA could allow disruption of OCS activities by third party special interest groups even if the state and federal government are satisfied that regulated conduct has been properly reviewed and permitted. The uncertainty produced by the factors enumerated above can, in and of itself, cause the shifting of high cost, long term job creating energy projects proposed for federal leases in the United States' OCS to overseas locations. In terms of our ability to maximize the domestic contribution to America's oil and gas supply, CZM challenges are being brought most in "frontier areas" where an estimated 81% of America's recoverable gas resources are thought to lie.

Recommendations for Improvement:

- **Activities Covered.** Under the CZMA, a consistency determination is necessary where activities "will have reasonably foreseeable affects on any land or water use or natural resource of a states' coastal zone."

  If a State alleges that a proposed activity is inconsistent with its CZM Plan, it must be required to specifically detail each of the expected affects, demonstrate why mitigation is not possible and identify the best available scientific information and models which show that each of the affects are "reasonably foreseeable." In order to be the basis for a determination of CZMA inconsistency, alleged adverse affects should have to be substantial, irreversible and unavoidable.

  No state CZM Plan should be approved by the Secretary of Commerce if its implementation would effectively ban an entire class of federally authorized and regulated activity.

- **Single Consistency Certification.** The energy industry has experienced lengthy delays in the permitting process due to a lack of coordination and communication between federal permitting agencies and affected coastal states. Due to the nature of offshore projects, various federal permitting agencies are involved in a stepped process which begins with exploration plans, includes development and production plans, pipeline installation and then ends with the removal of everything which has been installed when production ceases.

  Changes should be made which would provide for a single consistency certification process for proposed outer continental shelf oil and gas covering all federally licensed or permitted activities, including air and water permits. This would increase the efficiency of the process without in any way limiting the scope of a state's review or its access to information and data necessary for it to make its consistency determination.[10]

- **General Negative Determination.** Many federal agency and permitted activities, or components thereof, are repetitive in nature but, presently, Federal

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[10] See 30 C.F.R. Sections 250.203 and 250.204, plus 43 U.S.C. Section 1340(c)(3) and 43 U.S.C. 1351(d).

permitting agencies must make case-by-case specific determinations despite the fact that these activities will not have reasonably foreseeable coastal effects, individually or cumulatively. This is expensive and wasteful of both human and financial resources.

The efficiency of the federal consistency process would be greatly enhanced by the addition of a provision that would authorize the creation of "general negative determinations." This new determination would be similar to those created under the existing regulation for "general consistency deter-minations,"[11] and would cover repetitive In order to be approved by the Secretary of Commerce, State Coastal Management Plans should be required to contain determinations of which activities, undertaken far offshore from State waters, will or will not have reasonably foreseeable coastal effects. These should be listed and 15 CFR 930.53 should be modified to provide additional clarity and predictability.

- **Open-Ended Consistency Appeal Process.** As presently administered, the CZMA consistency override appellate process has taken anywhere from 16 months to 4 years.

  Several factors that need to be addressed in order for the consistency appeal process to work properly are discussed below:

  - **The Time Period.** Section 316 of CZMA provides that the Secretary of Commerce must issue a final decision on an override appeal no later than 90 days from publication of a Federal Register notice indicating when the decision record has been closed. However, experience has shown that override appeals can be drawn out indefinitely as there is no clear deadline for the close of the record or definition of what constitutes the record. Department of Commerce regulations at section 930.130 require that the notice of the close of the record should be published no sooner than 30 days after the close of the public comment period, but do not specify a deadline by which the record should be closed.

    The law (or the regulations) can be revised to include a reasonable deadline, such as 12 months from the date the appeal is filed, for the close of the record.

  - **The Record.** The Department of Commerce is concerned about its ability to compile a legally sufficient record if Congress mandates a specific time frame. Eliminating any ambiguity as to the definition of the term "record" within the context of the CZMA consistency appeal process should allow these concerns to be set aside.

Conclusion: Natural gas and oil operations on the United States' OCS contribute a significant proportion of our nation's present domestic energy supply and will become increasingly important in the decades ahead. The Coastal Zone Management Act and its consistency requirements will continue to have a direct, adverse effect on the ability of the Minerals Management Service to carry out its responsibilities under the Outer Continental Shelf Lands Act unless appropriate modifications are made to the CZMA and its regulations.

C. Marine Protected Areas

Issue Description: Several mechanisms exist outside of OCS moratoria in which exploration, development and production activities can be restricted or prohibited. These means are both direct and indirect.

The most common and broadly used direct mechanism is marine protected areas (MPAs). This internationally used phrase may include national parks, marine sanctuaries, estuarine reserves, wildlife refuses, local, regional and federal fishery management areas, critical habitats, wilderness areas, no take reserves and environmental sensitive areas. Globally, MPAs have grown from an inventory of 118 in 1970 to at least 1,306 in 1994. In the United States, NOAA has identified 328 Marine Managed Areas consisting of approximately 150,000,000 acres.

Specific indirect mechanisms impacting industry's ability to develop natural gas reserves include "customary international law" and NGO conferences, congresses and publications on MPAs and biological diversity. Our Mexican and Canadian neighbors have ratified the UN Convention on the Law of the Sea and the Convention on Biological Diversity. These conventions generate obligations to create marine protected areas in order to conserve biological diversity. Despite the lack of ratification, the United States, and other countries address conservation of biological diversity and MPAs in a regional approach such as

[11] 15 CFR 930.36(c).

with Mexico and Canada. Another indirect mechanism is the application of international development bank policies on ecosystem and sensitive areas management for international projects which creep toward the United States.

The most recent U.S.-based activity on MPAs is the 2000 Presidential Executive Order. This order mandates enhancement and expanded protection of existing MPAs. Appropriate recommendations include assessment of threats and gaps in levels of protection currently afforded to natural and cultural resources, practical and science based criteria for monitoring and evaluating the effectiveness of MPAs and identification of opportunities to improve linkages with international MPA programs.

Issue Impact: Local, state, regional, federal and international activities are at play to reduce industry's access to potential natural gas resources. The call for reduction or closure from interested parties within the MPA universe approaches 20% of U.S. seas, management areas, the EEZ and major ecosystems.

Excluding the U.S. moratoria, closure of the seas will contribute substantially to the further decline of critical natural gas supplies and have a chilling effect on industry's inventory of prospects.

For those areas allowing mitigation, the measures may lack a scientific base without consideration of a cost/benefit analysis. Mitigation measures will extend the cycle time for exploration, development and production projects

Costs will increase as environmental assessments and accompanying permits become more comprehensive, particularly in deepwater acreage.

Decreased access will impact the sustainability of communities, economics, and jobs, and increase the flight of U.S. capital for natural gas development to areas outside the United States.

Planned expansion of existing production may be curtailed.

A range of MPA precedents exist outside the U.S. These precedents are largely driven by international treaties (Convention on Biological Diversity) and UNEP. The precedents may be considered in the formulation of future U.S. policy and is reflected in the 2000 Presidential Executive Order.

Recommendations for Improvement:

1. Ensure understanding of science through adequately funded research. (MMPA, NOAA strategic plan, U.S. Commission on Ocean Policy, Pew Commission, NEP, OCS Policy Commission, CZM)

2. Continue to recognize multiple use of the seas and to protect the balance between living marine resources and non-living marine resources.

3. Involve key stakeholders (DOI) through efficient consultation.

4. Apply ICC definition of the precautionary principle.

5. Ensure existing MPAs are meeting their intended purpose and confirm minimal industry footprint.

6. Assess the positives and negatives associated with precedents outside the United States.

Example: Lessons learned from Flower Garden Banks, Mobile Bay, Galveston, B-T, NEPs.

Legal Authority:

1. Convention on Wetlands

2. Convention for the Protection of World Cultural and Natural Heritage

3. Regional Seas Program (Caribbean)

4. Law of the Sea? (U.S. has not ratified)

5. Convention on Biological Diversity? (U.S. has not ratified)

6. National Marine Sanctuaries Act

7. Magnunson – Stevens Fisheries Act

8. National Park Service Organic Act

9. Coastal Zone Management Act

10. National Wildlife Refuge System Act

11. National Wildlife Preservation System Act

12. Oil Pollution Act

13. Clean Water Act

14. Oceans Dumping Act

15. NEPA

16. ESA

17. MMPA

18. OCSLA

19. Archaeological Resources Protection Act

20. CERCLA

21. Fish and Wildlife Coordination Act

22. Marine Plastics Pollution Research and Control Act

23. Geneva Convention on the Law of the Sea (1958) (U.S. ratification?)

Agencies Involved:

- Department of Commerce
- Department of Interior
- Environmental Protection Agency
- Department of State

D. Marine Mammals Protection Act (MMPA) and Endangered Species Act (ESA) – Biological Opinions and Incidental Take Guidelines or Regulations

Issue Description: Recent actions by the National Oceanic and Atmospheric Administration (NOAA) and the Minerals Management Service (MMS) in the area of marine mammals and endangered species could significantly impact E&P operations in the deepwater Gulf of Mexico. The occurrence of these impacts is more likely if NOAA and MMS issue requirements for protecting endangered species and marine mammals based upon incomplete science and flawed process.

Issue Impact: Proposed mitigation measures could result in further delaying critically important domestic energy supplies through unnecessary and costly delays and generally reducing access to these valuable resources without solid scientific evidence that such actions would significantly enhance species protection.

Under the MMPA provisions, and because of the lack of information available on the feeding, migration and breeding habits of mammals in the Gulf of Mexico, NOAA and MMS have begun to implement protection for listed species. Until enough information has been gathered to determine the effects of oil and gas operations on certain species, MMS and NOAA will likely take preemptive action designed to protect these species. MMS discretion is limited on non-discretionary provisions stated in Biological Opinions issued by NOAA Fisheries on OCS activities to protect endangered or threatened species.

Recommendations for Improvement:

1. The E&P industry should support efforts by MMS and NOAA to use best available scientific information and data to define prudent and effective policy to protect marine mammals and endangered species.

2. A policy decision should be made to engage in more research before proceeding into unwise and expensive regulation.

3. Through process, we suggest a deeper and well-coordinated effort between NOAA and MMS.

Industry has created a task force consisting of the upstream trade associations and many of their members to work this issue. The purpose of the task force is to address the policy, legal, and scientific issues surrounding the ESA and MMPA as those laws, regulations and agency policies affect the oil and gas industry in the Gulf of Mexico. Task force membership is expected to reflect the broad policy, legal, and scientific implications of the issue. The task force will frame the issue, develop and implement a strategy to address policies and actions that are proposed or taken by government agencies or outside parties. The task force will dialogue with MMS and NOAA to try to add certainty to the process with MMS serving in a leadership role and NOAA being required to base decisions on sound science.

Example: Section 7 of the ESA requires any federal agency contemplating an action that could have an effect on a species covered by the act to contact NOAA and seek a Biological Opinion (BO) on the proposed activity so that actions can be taken to protect the protected species. The MMS responded to this requirement in the form of "Stipulation 5 – Protected Species," from OCS Lease Sale 184 and the Notice to Lessees that followed. This stipulation was in response to "mandatory" provisions in NOAA's BO, which were required in order for Sale 184 to be conducted.

Legal Authority:

1. Section 101 of the MMPA generally prohibits the taking of any marine mammal in U.S. waters.

2. Section 7 of the ESA requires any federal agency contemplating an action that could have an effect on a species covered by the act to contact NOAA and seek a BO on the proposed activity so that actions can be taken to protect the protected species.

3. Section 9 of the ESA prohibits wildlife listed as endangered from being subject to a "take" by any person within the United States, its territorial sea, or on the high seas.

Agencies Involved:

- Department of Interior/Minerals Management Service

- Department of Commerce/National Oceanic and Atmospheric Administration

E. U.S. Commission on Ocean Policy

Issue Description: The Commission was established by the Oceans Act of 2000; it is likely to recommend new ocean policy governance structures, fundamental ocean policy principles, and a variety of specific implementation recommendations. The Commission is unlikely to make specific recommendations concerning moratoria areas or improved OCS energy access, but will recognize the environmental stewardship, technology, and economic contributions of OCS energy. The final report is also likely to stress the increasing impacts of onshore non-point source pollution on the marine environment. The Commission is currently developing a draft final report to Congress and the President in August/September 2003;[12] the following recommendations are under consideration [11/22/02, 1/24/03, 4/1/03 USCOP public meeting discussion drafts].

Discussion: The Commissions guiding principles and recommendations must be implemented in a manner consistent with the following energy-oriented principles to effectively support improved OCS resource access and development:

- Recognition of OCS energy production as a clear national ocean resource priority and of the need for mixed and balanced use of all resources

- Maintenance of the DOI/MMS role as steward of offshore energy development

- Maintenance of existing federal administrative agency authorities and substantive ocean governance laws as the foundation for enhanced policy coordination and conflict resolution mechanisms

- Evaluation of recommendations against well-documented resource problems such CZMA reform, to ensure real potential for improvement

- Balanced consideration of environmental, economic, technical feasibility, and scientific factors in conflict resolution and policy coordination

- Enhancement of regulatory process certainty in ocean resource management

- Enhancement of a public/industry customer-based approach by government to ocean resource management.

Potential Recommendations:

- Establishment of The Executive Office of Ocean Policy, directed by an appointed Assistant to the President for Ocean Policy, with staff to support the Executive Office of Ocean Policy and the National Ocean Council.

- Creation by Executive Order, of a National Ocean Policy Framework, composed of an Executive Office of Ocean Policy, a National Ocean Council, and an Advisory Committee. The Executive Office and advisory committee should oversee and monitor implementation of Commission recommendations.

- Establishment of a new set of measurable national coastal management goals to:

  – ensure the economic and environmental vitality of coastal communities, waterfronts, tourism, and transportation; develop and implement a new, ecosystem-based approach

[12] The report will be available at http://oceancommission.gov.

- establish a deliberate and formal process for developing scientific information in support of decision making
- establish a more coordinated system of coastal management programs
- continue incentive-based approaches to coastal management as the focus of federal involvement; national goals should be established that can be measured and progress toward those goals should be directly related to the provision of federal funding.

- Stewardship: Ocean resources are held in the public trust. The government has special obligations to its citizens based on the public trust nature of ocean areas and resources and the government's responsibility to protect the interest of the public. The public should understand the importance of coastal and ocean waters and that their actions impact marine areas and resources. The public should recognize that they are citizen stewards of the oceans.

- Sustainability: Ocean policy should be designed to meet the needs of today without compromising the needs of tomorrow.

- Best Available Science: The decision making process should be based on an understanding of natural and social processes and influences that impact the marine environment.

- Transparency: Decisions and their rationale should be clear and available to all.

- Timeliness: Governance systems should operate with enough effectiveness, efficiency, and predictability to respond in an expeditious manner.

- Accountability: Responsibility for actions or tasks should be clear and unambiguous to all. Those who are involved in decision-making and implementation should be held accountable for their actions.

- Multiple Use: The oceans provide a wide range of current and future opportunities for economic activities, conservation, recreation, and other human endeavors. Management must recognize these multiple uses and objectives and balance competing interests.

- Precautionary Approach: A precautionary approach should be used in developing and implementing the required management plans for coastal and ocean resources and activities.

Statutory Authority:

- Oceans Act of 2000; Public Law 106-256

- OCS Lands Act

F. National Energy Policy Activities Affecting OCS Access

Issue Description: The May 2001 Report of the National Energy Policy Development Group, Chapter 5, "Energy for A New Century: Increasing Domestic Energy Supplies," provides the following assessments, conclusions, and recommendations. The Policy content has significant potential to support expanded future OCS energy access and development, but it currently lacks focus on supply-related access problems.

Discussion: The President's energy policy focuses on "21st Century Technology: The Key to Environmental Protection and New Energy Production." The following supply policy discussion documents continuing improvement in production technology, safety, and pollution prevention supporting increased access to OCS energy resources.

- New technology and management techniques allow for sophisticated energy production as well as enhanced environmental protection. The computer, three-dimensional seismic technology, and other technologies have transformed the process to one highly dependent on the most advanced and sophisticated technology available.

- Energy efficient drilling and production methods reduce emissions; practically eliminate spills from offshore platforms, enhance worker safety, lower risk of blowouts, and provide better protection of water resources. With each improvement in operational performance and efficiency, more oil and gas resources can be recovered with fewer wells drilled, resulting in smaller volumes of cuttings, drilling muds and fluids, and produced waters.

- Other examples of advanced technology include: 3-D seismic technology that enables geoscientists to use computers to determine the location of oil and gas before drilling begins, dramatically improving the exploration success rate; deep-water drilling technology that enables exploration and production of oil and gas at depths over two miles beneath the ocean's surface; high-powered lasers that may one day be used for drilling for oil and gas; and highly sophisticated directional drilling that enables wells to be drilled long horizontal distances from the drilling site.

- **Outer Continental Shelf**

- Congress has designated about 610 million acres off limits to leasing on the Outer Continental Shelf (OCS), which contains large amounts of recoverable oil and gas resources. These Congressional moratoria have been expanded by Presidential action through 2012, effectively confining the federal OCS leasing program to the central and western Gulf of Mexico, a small portion of the eastern Gulf, existing leases off California's shore, and areas off of Alaska.

- Concerns over the potential impacts of oil spills have been a major factor behind imposition of the OCS moratoria. For areas that are available for possible development, it is projected by NPC that with advanced technology, we could recover 59 billion barrels of oil and 300 trillion cubic feet of natural gas. This type of exploration and production from the OCS has an impressive environmental record. For example, since 1985, OCS operators have produced over 6.3 billion barrels of oil, and have spilled only 0.001% of production. Naturally occurring oil seeps add about 150 times as much oil to the oceans. Additionally, about 62% of OCS energy production is natural gas, which poses little risk of pollution.

- It is estimated there are significant undiscovered resources in the two planning areas of the Arctic OCS. Geologists estimate that there are approximately 22.5 billion barrels of oil and 92 trillion cubic feet of natural gas in the Arctic OCS. The Beaufort Sea Planning Area encompasses approximately 65 million acres. Active leases within the Beaufort Sea Planning Area represent only 0.4% of the total acreage, and only 5% of the leased acreage is being actively pursued for development and production. The Chukchi Sea Planning Area encompasses approximately 63.7 million acres, none of which is currently leased.

- **Natural Gas Production**

- Currently, natural gas provides about 16% of U.S. electricity generation. Seven states obtain over one-third of their generation from natural gas (Rhode Island, New York, Delaware, Louisiana, Texas, California, and Alaska). Perhaps more importantly, natural gas-fired electricity is projected to constitute about 90% of capacity additions between 1999 and 2020. The amount of natural gas used in electricity generation is projected to triple by 2020.

- Ensuring the long-term availability of adequate, reasonably priced natural gas supplies is a challenge. Low gas prices in 1998 and 1999 caused the industry to scale back gas exploration and production activity. Since 2000, the North American natural gas market has remained tight due to strong demand and diminished supplies. Last year, natural gas prices quadrupled, which resulted in substantially higher prices for electricity generated with natural gas.

- While the largest barriers to expanded natural gas electricity generation relate to production and pipeline constraints, there are several other barriers. Environmental regulations affect the use of gas for electricity generation. Although natural gas electric plants produce fewer emissions than coal-fired power plants, they still emit nitrogen oxides, carbon dioxide, and small amounts of toxic air emissions.

Recommendations – Energy for a New Century: Increasing Domestic Energy Supplies:

- The recommendation to open the ANWR 1002 area is included with the recommendations pertaining to OCS energy for completeness. The absence of specific recommendations addressing OCS moratoria areas reflects the difficulty in, and importance of, *action* on these and other national energy policy improvements.

- The NEPD Group recommends that the President direct the Secretary of Energy to improve oil and gas exploration technology through continued partnership with public and private entities.

- The NEPD Group recommends that the President direct the Secretary of the Interior to consider economic incentives for environmentally sound offshore oil and gas development where warranted by specific circumstances: explore opportunities for royalty reductions, consistent with ensuring a fair return to the public where warranted for enhanced oil and gas recovery; for reduction of risk associated with production in frontier areas or deep gas formations; and for development of small fields that would otherwise be uneconomic.

- The NEPD Group recommends that the President direct the Secretaries of Commerce and Interior to re-examine the current federal legal and policy regime (statutes, regulations, and Executive Orders) to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the Outer Continental Shelf (OCS).

- The NEPD Group recommends that the President direct the Secretary of the Interior continue OCS oil and gas leasing and approval of exploration and development plans on predictable schedules.

- The NEPD Group recommends that the President direct the Secretary of the Interior work with Congress to authorize exploration and, if resources are discovered, development of the 1002 Area of ANWR. Congress should require the use of the best available technology and should require that activities will result in no significant ad verse impact to the surrounding environment.

G. Comprehensive Federal Energy Legislation

Issue Description: Comprehensive federal energy legislation is the critical path for advancement in OCS energy access and supply development. HR 6 as passed by the House in April, and S. 14 as currently under debate in the Senate contain several technical, economic, and policy enabling provisions, but no meaningful direct OCS access improvements other than the S. 14 OCS inventory and related provision similar to the recommendation below

Discussion: In March 2003, the American Petroleum Institute provided Congress with the following assessment of the critical industry factors which must be recognized as the 108th Congress debates energy legislation, looking specifically at natural gas prices, drilling and production and the challenges to increasing future OCS and onshore energy access and development:

- Drilling has increased in recent years, but production has declined.

- U.S. natural gas production in the fourth quarter of 2002 was down about 4% from the fourth quarter of 2001. Indeed, U.S. natural gas production today is lower than it was five years ago, despite increases in drilling in recent years. In 2001, the industry drilled about 22,000 natural gas wells, nearly double the number of wells drilled in each of the four previous years. Drilling activity declined by 30% in 2002.

- Historically, rig counts and new production have lagged price rises.

- Higher prices do not necessarily lead to immediate increases in rig counts and new production. Additional production can take months or longer depending on factors such as availability of drilling equipment, labor availability, time to drill the well, infrastructure to connect to natural gas pipelines, and the weather at the production site.

- Traditional sources/fields are in decline.

- Since 1970, the United States has seen a progressive decline in the ability to satisfy natural gas demand growth from traditional sources – most of which are on private or state lands in the U.S. lower-48. While the United States is a “mature” area, untapped fields remain. However, finding and producing this gas is becoming more and more expensive. Canadian production also seems to be declining.

- Offshore production has declined in the shallow waters of the Gulf of Mexico. However, technology advances have allowed greater activity in deeper waters. Deepwater gas supplies offset most of the decline in shallow waters, thus stabilizing OCS gas supply. In addition to long lead times, deepwater fields tend to have shorter lives than onshore wells.

- Less mature areas such as the deep waters of the Gulf of Mexico and the eastern coast of Canada will help, but developing such areas can take years. In addition, the same technology that is helping us reach more areas is making it possible to deplete the gas found at a much faster rate, so that a typical well drilled today will decline at a faster rate than a well drilled 10 years ago.

- The denial or restriction of access, and barriers to development, have made the industry “prospect poor.”

- Nearly 40% of the potential domestic natural gas resource base on federal land is either off limits or only open to development under highly restricted conditions. Offshore, federal moratoria prohibit the exploration and development of some of the nation's most promising resources. Federal policies in the Rocky Mountains have also placed substantial resources off limits. Studies by the National Petroleum Council and the Interior Department have concluded that nearly 40% of the gas resource base in the Rockies is restricted from development either partially or totally.

- Opponents of drilling contribute to delay by exploiting conflicts in federal policies. For example, the Coastal Zone Management Act has been invoked by states to block natural gas pipeline projects as well as to block offshore leasing and development.

- Without production from areas currently under access and development restrictions, it is unlikely producers can significantly increase gas from the U.S. lower-48.

- Substantial E&P capital investment decisions, especially in frontier areas, are not based on short-term prices.

- To meet future natural gas demand, producers must invest many billions of dollars annually. Industry must compete against other domestic investment options that produce higher returns as well as competing against potentially lower cost foreign investments. Exploration and production planning can be risky because market volatility, as recently experienced, can deny producers reasonable assurance that their investments will be rewarded. For example, over the past two years prices have ranged from about $2 per million cubic feet of natural gas to $10 per million cubic feet. Prudent planning demands that producers average out prices over the long term to determine investments.

- There are serious infrastructure constraints.

- Even with greater access, there may be significant challenges to delivering new gas. In the Rockies, there is concern about adequate pipeline capacity. Similarly, to tap the huge natural gas reserves in Alaska, a new pipeline is needed. Permitting challenges are formidable in Alaska and the U.S. lower-48. Recent uncertainty in the energy markets and questions about future regulatory policy may also discourage new pipeline construction.

Recommendations: The 108th Congress should include the following provisions in a comprehensive Energy Bill that are relevant to improved OCS resource access; most of them are included in either H.R. 6 as passed by the House in April 2003 or are under consideration in the Senate:

- *Offshore Land Access and Development.* Support an inventory of OCS resources that will provide: an historic look at offshore resource estimates to demonstrate how they grow with time if exploration is allowed; an identification of impediments to development of offshore resources; and direction to DOI to work with stakeholders to make process recommendations for achieving broader public support for multiple and balanced use of offshore lands.

- *Codify Executive Orders (EO 13212 and EO 13211).* To expedite increased energy supply and availability to the nation by (1) considering the effect of federal regulations on the nation's energy supply, distribution and use, and (2) ensuring "energy accountability" within federal resource management agencies. Accountability may include requiring internal agency audits to establish performance measures and benchmarks for addressing permit backlogs and Resource Management Plan updates.

- *Coastal Zone Management Act Consistency Provisions.* Ensure timely action by the Secretary of Commerce on override decisions of state appeals under the Coastal Zone Management Act (CZMA). Set specific deadline (12 months) for decision on appeal with limited opportunity for extension of that deadline if more time is needed. Coordinate agency reviews for consistency into a single process.

- *Energy Permit Streamlining.* Congress should create an office should be formed in the Executive Office that is to coordinate energy permits, including energy permits in the OCS. A pilot should be conducted in the OCS that streamlines the OCS permitting process, which would include approvals related to OCSLA, MMPA, ESA, and other relevant statutes.

- *OCS Revenue Sharing.* Congress should support infrastructure and community impacts from OCS development by directing a portion of the royalty revenue stream to affected coastal states.

- *Bipartisan Commission.* Congress should create an independent blue-ribbon bipartisan energy supply commission along the lines of the Base

Realignment and Closure Commission (BRAC). The new commission should, work with the *administrative interagency advisory task force* we also recommend, to reach a high-level federal and state government decisions allowing the nation to move forward on a more balanced natural gas supply policy for the OCS.

– BRAC introduced a model by which important national decisions with far-reaching impacts were elevated above the political fray which is necessarily defined by local, short-term interests. Members of the commission were appointed in a bipartisan manner and represented expertise in military affairs, economic development, land-use and local, regional and national issues.

– In this way, politicians fearful of reprisals from local interest groups could effectively delegate these difficult choices to a body of experts, which was removed from the pressures of campaigning and re-election. A long-term plan with broad national support was crafted and implemented, and has since been recognized as a tremendous success.

– Once again, we find ourselves at an impasse. Many coastal state representatives are caught between a rock and a hard place: coastal populations continue to grow and demand affordable and abundant supplies of energy. However, it is politically untenable for any individual representative to vote in favor of allowing development near their coastal waters.

– As exploration and production technology has improved and the U.S. industry has established an excellent safety and environmental record, this policy paradox no longer makes sense. But our traditional means of policy development hold no solutions for compromise or progress.

– A commission or commissions, modeled on the BRAC might be one answer. Using this model, the nation could develop policy that is far-reaching and not held hostage to parochial demands of a given moment in time.

H. The Pew Oceans Commission

Issue Description: The Pew Oceans Commission is an independently funded research and policy group, chaired by Mr. Leon Panetta, focused primarily on the future policies needed to restore and protect living marine resources in U.S. waters.

Discussion: The commission has to some degree participated in the U.S. Commission on Ocean Policy process, but has generally taken an independent path. The commission will make its recommendations to Congress and the nation in early 2003.

The Pew Commission provided interim conclusions and recommendations, as follows, before the U.S. Commission on Ocean Policy in Anchorage in August 2002.

- Pollution from cities and farms finds its way into the oceans, and has already created a 12,000 square mile “dead zone” in the Gulf of Mexico.
- Every eight months, 10.9 million gallons of oil running off our streets and driveways reaches our oceans.
- Half of America’s population already lives along our coastlines and that’s projected to increase to 75% over the next two decades. Our scientists say this increased development “will impair water quality in coastal streams and can damage coastal wetlands that are vital nursery grounds for many marine species.
- Governance is fragmented at best and often hopelessly grid locked.

Recommendations: The Pew Commission conclusions and recommendations focus on improving living resource protection and an enhanced role for local and regional stakeholders in national energy and other OCS resource decisions. The recommendations are not likely to be directly adverse to current OCS energy production, but are likely to reflect a policy bias, driven by the Pew view of the “precautionary principle,” against expanding access to OCS energy supplies.

This expected bias appears largely unsupported by the policy and technical work done by the Commission, including the research and conclusions in the 2001 Pew Marine Pollution in the United States report available on the Pew website. The report contains a thorough assessment of significant coastal and marine pollution, which in generally puts the threat of pollution from new energy exploration and production activities in perspective as much less significant that other onshore and coastal human uses and activities, particularly onshore non-point source pollution.

The Pew commission supports adoption of a National Oceans Policy Act, modeled after statutes such as the National Forest Management Act. The Act would implement policy binding on all activities affecting United States Ocean waters and resources, and provide clear standards against which performance can be measured and a mechanism through which compliance can be assured.

The policy would establish a governance system to protect, maintain and restore marine biological diversity; manage activities on an ecosystem basis; utilize the best available scientific, social, and economic information for decisions; support necessary research and education in improving the understanding of marine ecosystems; result in governance that is equitable, transparent, and accountable; and balance the legitimate interests of federal, regional, state, and private stakeholders.

I. The OCS Moratoria on Offshore Drilling and Development

Issue Description: The OCS moratoria on offshore drilling and development affecting the U.S. Atlantic and Pacific Coasts, parts of the Eastern Gulf of Mexico, and parts of Alaskan offshore waters (North Aleutian Basin) constitute the most significant barrier to future U.S. energy access and development.

Discussion: OCS moratoria were never envisioned when the first federal lease sale of OCS hydrocarbon rights occurred in 1954. Tracts in the Gulf of Mexico seaward of Louisiana were auctioned off just one year after the passage of the Outer Continental Shelf Lands Act. Since that time, lease sales have occurred, with few exceptions, at least annually in the Gulf. Submerged federal lands off the coast of California, Florida, and other coastal states were gradually added to the program.

However, the expansion of federal leasing came to a rapid halt in 1969, when the accidental release of more than 71,000 barrels of oil from Unocal's Platform A in Santa Barbara channel, fouled wildlife and a significant swath of California coastline. Public outcry generated by the event solidified resulted in the immediate cancellation of additional leases sales in the Pacific region for five years; initial sales in Alaska and Atlantic regions were also postponed. Numerous environmental laws were passed in the next few years including the National Environmental Policy Act and the Coastal Zone Management Act.

The oil embargoes of 1973 and 1974 disrupted world energy markets, causing significant shortages, long lines at gasoline pumps and huge price increases. Renewed attention was focused on the OCS as a potential means of insulating the United States against the volatility of world oil markets. President Nixon's "Project Independence" called for the Secretary of the Interior to expand OCS leasing to 10 million acres in 1975 – nearly triple what had been offered previously. Sales in the Pacific region resumed in 1975, in the Atlantic in 1975, and in Alaska in 1977. Major amendments were made to the Coastal Zone Management Act in 1976 to facilitate energy facility siting and other energy development, and to recognize energy supplies as a national priority.

However, outside of the central and western Gulf of Mexico, actual implementation of OCS leasing was fraught with controversy, litigation, and other roadblocks. To expedite energy production, then-Secretary of the Interior James Watt, combined all of the leasing, regulation and research functions related to OCS development and placed them under the authority of the MMS in 1982. Then in 1983, Watt expanded the area wide-leasing program that had worked successfully in the central and western Gulf of Mexico to all OCS areas. This procedure opened large areas to development instead of limited, specifically designated tracts. Public reaction to the move was swift and states and localities that had never undergone OCS development in the past reacted negatively to the prospect. By the mid-1980s, Congress was routinely limiting which portions of the OCS could be leased by attaching riders to appropriations legislation for the Department of the Interior that stipulated how and where funds could be spent.

This controversy culminated in 1990, when President Bush announced a moratorium on lease sales seaward of the entire east and west coasts of the United States until the year 2000. In the interim period, President Bush ordered the Interior Department to assess the effects of OCS development, select more carefully the areas slated for development, and to prepare legislation that would give states directly affected by OCS development a greater share of the financial benefits resulting from this development. In the year 2000, however, President Clinton extended this leasing ban until 2012.

For practical purposes the result of this controversy has been to close down the OCS of most of the continental United States to development. Certain leases seaward of California continue to produce and very limited production has recently come online in the federal OCS of Alaska. However, the central and western Gulf of Mexico are the regions where more than 90% of OCS oil and nearly 99% of OCS natural gas is found and produced. A limited sale recently took place in a small section of the eastern Gulf seaward of Alabama, but no production has resulted to date.

Less than 20% of the federal OCS is open to offshore energy exploration and development – either currently under lease or scheduled for lease sales through the next five-year plan. Areas of the OCS currently off limits to leasing activity are estimated to contain about 16 billion barrels of oil and nearly 62.2 trillion cubic feet of natural gas. This represents approximately one-third of the total oil resources estimated to remain to be discovered offshore of the U.S. lower-48. As a point of reference, 70 trillion cubic feet could fuel the current residential needs of the entire United States for 14 years; 16 billion barrels of oil would sustain domestic production equal to current imports from Saudi Arabia for 27 years.

This study has updated resource estimates as compared to the MMS estimates in the figure below. Regardless of incremental revisions in OCS resource assessments, however, the importance of natural gas and oil resources in areas under current OCS moratoria cannot be overestimated.

Recommendation: The extensive OCS moratoria preclude development without regard to the nation's energy needs, the rational evaluation of environmental and economic costs and benefits, available technologies to prevent or remedy any environmental impacts, or other means of addressing conflicting uses. In President Bush's 1990 Executive Order implementing the leasing moratoria he stated his intent to "allow time for additional studies to determine the resource potential of the area and address the environmental and scientific concerns which have been raised."

Most of these studies are complete or continuing; however, understanding of the reserve potential and the environmental characteristics of an area expand more quickly when an area is available for leasing rather than under moratoria. Pre-leasing activities in priority moratoria areas should be authorized by the 108th Congress after due consideration of regional issues. The extensive MMS pre-leasing process may demonstrate the impracticality of developing some areas; it will also ensure that the information is available to make informed decisions about oil and gas leasing and development in key OCS areas.

Statutory Authority: Continuing DOI Appropriations (From FY 1982 to the present) – HR 5093 (Current FY 2003), S. 2708, consolidated resolutions; OCS Lands Act Sec. 12.

J. The MMS OCS Policy Committee

Issue Description: The MMS OCS Policy Committee is one of three advisory groups under the Minerals Management Advisory Board; it is chartered under the provisions of the federal Advisory Committee Act along with the scientific and royalty policy committees. The OCS Policy Committee gives advice related to discretionary functions of the Outer Continental Shelf Lands Act, representing the collective viewpoint of coastal states, environmental interests, industry, and other parties to the Secretary of the Interior through the Director of the Minerals Management Service. These functions include all aspects of leasing, exploration, development and protection of OCS resources.

There are three categories of members on this Committee; the diverse membership has generally frustrated the ability of the Policy Committee to have a positive impact on policies to expand OCS energy access. The Governor of each coastal state appoints state representatives. A coastal state is any state bordering on the Atlantic, the Pacific, the Gulf of Mexico, or the Long Island Sound. The Secretary of the Interior may appoint up to 12 members from the private and public sector to serve 2-year terms; currently energy producers, services, local government and environmental stakeholders are members. Appointments are to balance the Committee in terms of background, constituency, points of view, and function. Federal, Ex Officio Members are the Departments of Commerce, Defense, Energy, and State.

Discussion: The Policy Committee over the last decade has prepared several thorough reports and submitted numerous recommendations concerning expanded OCS energy supply access. The recommendations of two of these subcommittees are incorporated below. Many of the conclusions remain valid today, but they also reflect political pressure and uncertainty that has prevailed for over a decade. The result has been that the MMS continues to "study" environmental and socio-economic moratoria issues without the DOI adopting any specific policy recommendations addressing moratoria areas. The Administration and Congress need to move beyond the "study" phase, to an informed debate on the national and regional policy choices which must be made concerning future OCS energy resource access. This "continued study, policy decision deferral" paradigm is reflected in the following excerpt from the 1998 MMS report:

> *The Subcommittee on Environmental Information for Select OCS Areas Under Moratoria* was jointly established by the Outer Continental Shelf (OCS) Policy and Scientific Committees of the Minerals Management Advisory Board in January 1996. The purpose of the subcommittee was to independently review, evaluate, and provide guidance on information needs for OCS areas where leasing is now prohibited (termed moratoria), but may be considered in the future.
>
> These moratoria areas, created through Congressional/Presidential action since 1982, are estimated by the Minerals Management Service (MMS) to contain significant quantities of undiscovered and conventionally recoverable oil and natural gas. During its deliberations for assessing information needs and providing guidance on gathering information for decision purposes, the subcommittee considered the findings and recommendations of the National Research Council's (NRC) reports addressing the MMS' Environmental Studies Program (ESP) and other related OCS issues, as well as the MMS's response to those findings and recommendations. In addition, the subcommittee considered the following issues:
>
> - the amount of undiscovered oil and natural gas resources and the physical form (natural gas versus oil) of petroleum resources estimated for moratoria areas;
> - recent advances in technologies and procedures of the offshore petroleum industry;
> - the environmental record of the offshore petroleum industry; and
> - ESP budgetary constraints.

Recommendations: *OCS Policy Committee Subcommittee on Environmental Information for Select OCS Areas.*

1. *The MMS should proceed with environmental studies in moratoria areas.* The subcommittee neither endorses nor opposes opening moratoria areas for future leasing. The subcommittee does recognize, however, that future energy requirements may lead to the need to explore and produce oil and natural gas in these areas. Should this occur, the MMS must be prepared to predict, assess, and manage the impacts from oil and natural gas operations.

2. *Congress should support environmental studies in moratoria areas with new funds.* Funding for the ESP has declined from a high of $55.5 million in 1976 to $14 million in 1996. Current funding is insufficient to provide for adequate study of both moratoria areas and those areas currently experiencing OCS exploration and production.

3. *The MMS should request the funds necessary to initiate environmental studies in moratoria areas in its 1999 budget.* Because of the time requirements from study planning and initiation to publication of the scientific results, the subcommittee recommends that appropriate environmental studies for moratoria areas be started as soon as possible. These studies should be administered and directed by MMS because of the high level of direct interaction needed among MMS, stakeholders, and researchers.

4. *The MMS should maintain, or have access to, up to-date, basic information on oil and natural gas resources and natural resources within moratoria areas.* The MMS should use the most sophisticated technologies available to refine and update its assessment/inventory of oil and natural gas resources in all OCS planning areas. In addition, the MMS should also maintain or have access to basic knowledge of important natural and cultural resources and oceanographic features in all OCS planning areas. [Consider this 1999 recommendation in light of the current controversy concerning OCS inventory provisions in S. 14].

5. *The MMS should establish a social and economic studies program that includes current data for all OCS areas, including moratoria areas.* As with natural resources, a basic level of social and economic data should be collected in all OCS planning areas and updated as needed. These data are especially important in moratoria areas to examine potential costs and benefits to affected communities. Workshops should be conducted in all OCS planning areas to assist in delineating regional and sub regional research needs.

6. *The MMS should maintain knowledge of key issues and of information needs in moratoria areas.* The

MMS should maintain experts to assist in identifying and responding to national and regional specific issues. The MMS should consult with the members of the Minerals Management Service Advisory Board and university researchers to identify key scientific issues and information needs.

7. *The subcommittee recommends that the MMS refine its generic process for identifying the studies required to be performed in moratoria areas to meet information needs and formulate a strategy for this process that includes affected States and other stakeholders, including industry*. The MMS should be cognizant of all recent environmental studies, new technologies, and industry interest. Due to a variety of factors, environmental study priorities may have changed in some planning areas since the NRC reviews. The MMS is encouraged to develop new strategies with the participation of all stakeholders, for inventorying information available and identifying and selecting environmental studies necessary for making leasing decisions.

8. *The MMS should continue to be supportive of the development of new and advanced technologies that improve operational performance and reduce environmental risk*. Numerous technological advances that enhance and improve all facets of OCS operations have been made over the last several years. However, a concerted Federal-industry effort to improve technologies must continue in order to ensure that all OCS activities are performed in a manner that minimizes environmental risks and maximizes economic benefits.

9. *Environmental studies should be tailored to the different environmental risks associated with the production of oil versus natural gas*. The different environmental risks associated with the production of liquid oil versus natural gas should be considered when developing study needs for moratoria areas. The principal difference in environmental risk associated with the exploration and production of oil versus natural gas is the danger of accidentally spilled oil compared to the release of volatile natural gas. Other environmental risks are similar for oil or natural gas production. Environmental studies and evaluations should recognize these differences.

10. *The MMS should support and expand environmental studies in cooperation with other Federal and State agencies, universities, and industry*. Reduced ESP budgets, as well as the need to use monies in areas with active leasing, significantly limits the funding of studies in moratoria areas. Cooperation between Federal and State agencies, local universities, and industry will provide the MMS with the opportunity to leverage limited funds and better identify environmental conditions and issues of local concern. However, cooperative funding efforts should not limit the ESP funding or restrict study priorities.

Recommendations: *2001 Report from the Subcommittee on Natural Gas OCS Policy*. The committee considered the available information concerning the supply and demand for energy in the United States, and found that natural gas should be considered as a significant part of an energy base including alternatives and conservation programs, and made the following recommendations which continue to be instructive as our nation develops an energy policy for the future [the CD-ROM that is available with this report also contains a review of known, and foregone, geologic basin gas plays in moratoria areas]:

1. The Outer Continental Shelf (OCS) should be viewed as a significant source for increased supply of natural gas to meet the national demand for the long term.

2. Congressional funding to MMS and other critical agencies such as Fish and Wildlife Service, National Marine Fisheries Service, DOE, and EPA, should be assured to allow staff to accomplish the work necessary to increase production of natural gas in an environmentally sound manner from the OCS.

3. Future production will have technical and economic challenges; therefore, following on the success of the deepwater royalty relief program, MMS should develop economic incentives to encourage new drilling for natural gas in an environmentally sound manner in deep formations, subsalt formations, and in deepwater. Such incentives should be considered for both new leases and existing leases to maximize the use of the existing natural gas infrastructure on the OCS.

4. The MMS, in cooperation with industry, should encourage increased natural gas production in an environmentally sound manner from existing OCS leases.

5. The Policy Committee supports the existing 5-year leasing program. However, the leasing process can

be improved with increased congressional funding for mitigation, including impact assistance funds, revenue sharing, and local participation in the decision making process.

6. Encourage congressional funding for additional education and outreach regarding the leasing program.

7. With regard to improving the leasing process, the Policy Committee also recommends that MMS: include the mitigation of local social, cultural, and economic impacts within its policy determinations and recommendations; consider how the Bureau can restructure its decision making process to provide for greater input from local communities, including the opportunity for MMS, the industry, and local residents to attempt to reach agreement on controversial matters and how they should be adjusted, remedied, or mitigated – at specific times and places that various activities occur; conduct a comparative assessment of environmental risk between offshore and onshore production, where onshore reserves exist in the same area as offshore reserves; encourage operators to provide natural gas to the local communities in all areas. Specifically in Alaska, give special consideration to local, social, cultural, and economic impacts in northern Alaskan communities, in light of the unique subsistence culture in and the remoteness of, these communities; adopt as a resource tool the 1994 NRC Committee report entitled "Environmental Information for Outer Continental Shelf Oil and Gas Decisions in Alaska" (National Academy Press, 1994).

8. The MMS, partnering with DOE, should expand cooperative research with other agencies and industry seeking technical solutions to leading edge issues such as seismic imaging of subsalt areas and drilling in deep formations.

9. The MMS, in cooperation with DOE, should encourage international cooperation in development of gas hydrates in an environmentally sound manner, with a goal of a pilot program in place within 10 years.

10. A gas pipeline from Alaska to the U.S. lower-48 would favorably encourage an increase in natural gas production by creating favorable economics for Federal OCS production in Alaska. The Policy Committee recommends that DOI work with other agencies to expedite all appropriate permit reviews for such a pipeline.

11. To help develop information and enhance an informed public debate on whether or not there are grounds and support for a limited lifting of moratoria in existing moratoria areas, the MMS in consultation with industry and affected states, should identify the 5 top geologic plays in the moratoria areas, and if possible, the most prospective areas for natural gas in the plays that industry would likely explore if allowed. The following process would be used: encourage congressional funding to MMS for the acquisition of seismic data to assist in narrowing down prospective areas. It is important that these data be nonproprietary, which would be the case if acquired exclusively by MMS; encourage congressional funding for environment and social/human impacts studies for broad based or specific to 5 prospective geological plays; encouraging dual fuel capacity for new electricity generating plants; encouraging the review by the Administration of cost-effective tax incentives to increase the production of natural gas; encouraging conservation and increasing efficiency in the use of natural gas, as a part of a national energy policy portfolio.

The fair conclusion to be drawn from the extensive works developed and cited by the Policy Committee, in the context of improved access to OCS energy resources, is that most if not all significant national policy and scientific issues have been and continue to be adequately studied, while critical policy decisions on future domestic energy supply continue to be deferred.

Statutory Authority: Federal Advisory Committee Act, 5 U.S.C App. 2.

K. National Oceanic and Atmospheric Administration (NOAA) Strategic Plan

Issue Description: NOAA has recently completed a strategic planning process for the years 2003-2008. NOAA conducted an elaborate stakeholder engagement process to obtain assistance from stakeholders in creating a new strategic plan and ensuring that their transformation results in better products and services for their customers and the American public. NOAA hosted a series of "strategy and performance" dialogues and workshops with stakeholders from industry, nonprofit organizations, academia, state and local governments, and others. These workshops surveyed perspectives and solicited feedback on questions related to science, management improvement, and overall agency integration.

Issue Impact: NOAA is an increasingly important agency for the offshore oil and gas industry. Recent actions by the NOAA in the area of marine mammals and endangered species could significantly impact E&P operations in the deepwater Gulf of Mexico. Further, NOAA's administration of the Coastal Zone Management Act (CZMA) and the Federal Consistency Regulations at 15 CFR Part 930 implementing the CZMA have a long history of impeding energy exploration, development and production in offshore areas other than the Central and Western Gulf of Mexico. The Federal Consistency Regulations were recently revised, and the CZMA is presently up for reauthorization in Congress.

Recommendations for Improvement:

1. We recommend that NOAA, as an agency with regulatory responsibilities over the oceans that produce more than 25% of the U.S. current energy production, recognize the importance of the energy industry to the nation and allocate all necessary funding, staffing and effort to the achievement of this priority.

2. We recommend that NOAA work with other federal and state government agencies to coordinate the regulation of energy-related activities.

3. We recommend that the Secretary of Commerce join with the Secretary of Interior to examine current federal legal and policy regime to determine if changes are needed regarding energy-related activities and the siting of energy facilities in the coastal zone and on the OCS as prescribed in the President's National Energy Policy Development Group outlined these issues in the National Energy Policy published in May 2001.

4. We recommend the creation of working partnerships with industry to increase ocean and coastal areas explored, mapped, characterized and inventoried. We support the advancement of hydrographic data and information about the ocean environment.

5. We recommend that NOAA conduct research to understand and describe the ecological and biological population aspects of protected species as a basis for sound management decisions. The biological and ecological factors related to the population and habitat abundance and health of marine mammal populations protected by NOAA should be fully understood before the agency takes regulatory action.

6. We recommend that all of NOAA's actions, regulations and policies should be based on the best available scientific information and data with clear benchmarks, and outside peer review.

Example: Section 7 of the ESA requires any federal agency contemplating an action that could have an effect on a species covered by the act to contact NOAA and seek a Biological Opinion (BO) on the proposed activity so that actions can be taken to protect the protected species. The MMS responded to this requirement in the form of "Stipulation 5 – Protected Species," from OCS Lease Sale 184 and the Notice to Lessees that followed. This stipulation was in response to "mandatory" provisions in NOAA's BO, which were required in order for Sale 184 to be conducted.

Legal Authority: In a July 1970 statement to Congress, President Nixon proposed creating NOAA to serve a national need "...for better protection of life and property from natural hazards...for a better understanding of the total environment...[and] for exploration and development leading to the intelligent use of our marine resources.…" On October 3, NOAA was established under the Department of Commerce.

Agencies Involved:

- Department of Commerce

- National Oceanic and Atmospheric Administration

IV. Comparison of the 2002 EPCA and 2003 NPC Rocky Mountain Access Studies

The 2002 EPCA Rocky Mountain gas resource access study evaluated access to gas and oil resources on federal lands in the Green River, Uinta-Piceance, Powder River, and San Juan Basins and in the Montana Thrust Belt. The study was based upon analysis of lease stipulations, and the methodology was to overlay the lease stipulation information with play level maps of undiscovered resources.

The current NPC study evaluates access on all land types in the Rockies (federal, Indian, state, and fee lands). The NPC study expands upon the EPCA study and quantifies the impact of not only lease stipulations, but also the cumulative impact of conditions of approval, both in terms of no-access areas and higher costs.

The purpose of this section is to explain the differences in the resource base and access methodology for these studies, and to compare the results on an equivalent basis.

A. Scope and Methodology

1. EPCA

The EPCA study is titled "Scientific Inventory of Onshore Federal Lands' Oil and Gas Resources and Reserves," and was published by the Departments of Interior, Agriculture, and Energy. It evaluated the impact of federal lease stipulations on federal lands in the major gas-bearing basins of the Rockies. Since it was limited to federal lands, it did not attempt to evaluate restrictions on Indian, state, or fee lands. It also did not consider the impact of "conditions of approval" that are often required in order to drill a well in these areas.

The approach was to first map the 2002 USGS play level assessments for the five basins. These play level maps were aggregated to account for play overlap, resulting in a resource "density" map. This map was intersected with mineral ownership and lease stipulations.

The study originally intended to evaluate proved reserves, reserve growth, and undiscovered resources. However, due to time limitations EIA was not able to provide the analysis of reserve growth for the study. As a result, EPCA does not include the reserve growth resource, but does include proved reserves, which are all classified as "standard lease terms."

The EPCA study categorized undiscovered resources into 10 categories of access:

1. *No Leasing – Statutory/Executive Order*. Areas that cannot be leased due to Congressional or Presidential action. Examples include national parks, national monuments, and wilderness areas.

2. *No Leasing – Administrative, Pending Land Use Planning or NEPA Compliance*. Federal administrative areas that are currently undergoing land use planning or NEPA analysis and are not currently available for leasing.

3. *No Leasing – Administrative*. Areas in which leasing does not occur because of discretionary decisions made by the Federal land management agency. Includes endangered species habitat and historical sites.

4. *Leasing – No Surface Occupancy*. Areas that can be leased but stipulations generally prohibit surface occupancy for exploration and development activities to protect identified resources. Treated in the EPCA analysis as no-access areas (administrative). However, the resource can technically be accessed by directional drilling.

5. *Leasing – Cumulative Timing Limitations of >9 months*. Areas that can be leased, but stipulations limit the time of year when oil and gas exploration and drilling can take place. Timing limit stipulations prohibit surface use during specified times during the year. In this category, the timing limitations represent more than 9 months per year.

6. *Leasing – Cumulative Timing Limitations of 6-9 months*.

7. *Leasing – Cumulative Timing Limitations of 3-6 months*.

8. *Leasing – Cumulative Timing Limitations of <3 months*.

9. *Leasing – Controlled Surface Use*. Areas that can be leased, but stipulations control the surface location of exploration and development activities by excluding them from certain portions of the lease.

10. *Leasing – Standard Lease Terms*. Areas that can be leased and where additional stipulations are added to the standard lease form. Standard lease terms, however, still dictate that the lessee comply with a number of environmental and other requirements.

2. 2003 NPC

The goal of the 2003 NPC access study – as with the 1999 study – was to evaluate industry access to the entire gas resource base, including federal, Indian, state, and fee lands in the entire Rocky Mountain region. In addition, the NPC wanted to go beyond previous access work to fully assess not only lease stipulations, but also the cumulative impact of "conditions of approval." As in the 1999 NPC study, the goal was to categorize resources as "no-access," "increased costs," and "standard lease terms."

Because several COA restrictions exist for any given well location, the study group determined that the best way to evaluate these impacts is a Monte Carlo statistical model. This model is described in detail separately in this report. The model evaluates federal, state, and fee lands separately. Within each land type, the Monte Carlo analysis develops a matrix of access restrictions in terms of months of delay and increased costs per well.

It was assumed for the study that a delay of nine or more months per year effectively takes an area off limits. The total off limits for each basin and land type (federal, state) was determined. Subsequently, the "statutory" portion of the off limits was determined using percentages developed in the EPCA study. This allows the breakout of no-access into "statutory" (areas such as parks and wilderness) and "conditions of approval" (areas that are technically available to lease but are rendered as no-access through conditions of approval amounted to a cumulative impact of nine months per year or more).

The "high cost" portion of the resource base was determined as that portion of the resource with a cumulative cost impact of $100,000 or more per well. All resources that are accessible, and not high cost are classified as "standard lease terms." Therefore, the NPC categories are:

- No access –statutory (derived from EPCA federal analysis)
- No access – cumulative conditions of approval (9 or more months restriction per the Monte Carlo model)
- Accessible but high cost ($100,000 per well threshold per the Monte Carlo model)
- Standard lease terms – all remaining resources

In terms of the natural gas resource base, the NPC study is similar to EPCA in many respects. However, the NPC Supply Task Group, while relying heavily on the new USGS assessment, made a number of changes to the assessment that are incorporated into the new access study. For example, the NPC has a much higher resource for Powder River coal than was assessed by USGS. These differences, while not affecting the access percentages, do affect the volumes of gas that are available or off-limits.

In terms of methodology, the NPC used the Monte Carlo model to evaluate access to *undiscovered* resources. An additional estimate was made for reserve appreciation (growth to existing fields): 60% of this gas is assumed to be standard lease terms and 40% is higher cost. (This was the same assumption used in the 1999 NPC study.) As with the 1999 NPC study, proved reserve volumes are not explicitly included in the NPC access analysis, but are treated as having no restrictions for the purpose of the NPC forecasting model runs.

It should be emphasized that in order to compare the NPC access study with the EPCA study, an equivalent resource base must be used. This means that the proved reserves must be removed from the EPCA study, and the reserve appreciation resource and access assumption must be removed from NPC. In this way, the studies can be compared on the basis of undiscovered gas resource.

B. Resource Assessments

Exhibit 1 shows EPCA, USGS, and NPC resources by basin. EPCA used the revised 2002 USGS resource assessment and the values are identical. The USGS resource base is included in the table because the EPCA study did not publish the individual components, such as coal bed methane, tight gas, and new fields.

The third column shows the NPC assessment and the last column is the difference between NPC and EPCA. The new NPC assessment relied heavily upon the USGS, but there are some large differences.

Differences primarily occur in the coal bed methane and tight gas assessments. The NPC supply group has a larger volume of coal bed methane in the Powder River and Uinta-Piceance basins, and has a lower coal bed assessment in the San Juan. The largest tight gas difference is in the Green River Basin, where NPC is 14.8 trillion cubic feet lower than USGS. In all basins, the NPC new field assessments are higher because of the addition of small fields (6 billion cubic feet and less) to each play, which are not included by USGS.

The lower portion of Exhibit 1 summarizes the undiscovered resources by basin, and shows the aggregate difference between EPCA and NPC for these four basins. In aggregate, the NPC is only 4 trillion cubic feet lower than EPCA. At the basin level, the largest difference with EPCA is in the San Juan, as a result of the lower NPC coal bed assessment.

Exhibit 2 is a breakout of federal vs. non-federal undiscovered resources. The table shows that the federal fraction of undiscovered gas was determined in the EPCA analysis, and this fraction was used in the NPC study. Not shown here is the additional breakout of the non-federal resource into Indian and combined state and fee. The Indian lands percentage was based upon play level information from the 1999 NPC study, and

Comparison of EPCA and 2003 NPC Gas Resources - Rockies
Total Gas, Current tech, BCF

		2002 USGS	2002 EPCA		2003 NPC	Difference NPC vs USGS/ EPCA
Powder River Basin						
Discovered						
	proved reserves	not incl.	2,398		2,399	1
	growth	not incl.	not incl.		957	
Undiscovered						
	new fields	1,011	1,011	*	1,478	467
	tight nonassoc.	787	787	*	764	-23
	tight associated	424	424	*	0	-424
	coalbed	14,264	14,264	*	19,408	5,144
	low btu	0	0		0	0
		16,486	16,486		21,650	5,164
	control		16,487			
			* EPCA used USGS resource base but did not publish the details			
Green River Basin						
Discovered						
	proved reserves	not incl.	12,703		12,703	0
	growth	not incl.	not incl.		7,299	
Undiscovered						
	new fields	2,421	2,421	*	4,729	2,308
	tight nonassoc.	80,578	80,578	*	65,764	-14,814
	tight associated	62	62	*	0	-62
	coalbed	1,529	1,529	*	1,966	437
	low btu	0	0		14,535	14,535
		84,590	84,590		86,994	2,404
	control		84,590			
Uinta-Piceance						
Discovered						
	proved reserves	not incl.	7,182		7,182	0
	growth	not incl.	not incl.		3,824	
Undiscovered						
	new fields	213	213	*	2,063	1,850
	tight nonassoc.	18,828	18,828	*	22,826	3,998
	tight associated	64	64	*	0	-64
	coalbed	2,319	2,319	*	5,862	3,543
	low btu	0	0		0	0
		21,424	21,424		30,751	9,327
	control		21,661			

Note: the published EPCA undiscovered resource base is 237 Bcf high to USGS (see San Juan - Paradox)

Exhibit 1. Comparison of EPCA and 2003 NPC Rocky Mountain Access Studies

Exhibit 1 (continued)

San Juan and Paradox

		2002 USGS	2002 EPCA	2003 NPC	Difference NPC vs USGS/ EPCA
Discovered- San Juan only					
	proved reserves	not incl.	not incl.	19,621	
	growth	not incl.	not incl.	5,418	
Discovered- Paradox only					
	proved reserves	not incl.	not incl.	1,033	
	growth	not incl.	not incl.	995	
Discovered - San Juan + Paradox					
	proved reserves	not incl.	20,654	20,654	0
	growth	not incl.	not incl.	6,413	
Undiscovered (San Juan)					
	new fields	165	165 *	671	506
	tight nonassoc.	26,180	26,180 *	21,002	-5,178
	tight associated	0	0 *	0	0
	coalbed	24,240	24,240 *	8,413	-15,827
	low btu	0	0	0	0
		50,585	50,585	30,086	-20,499
	control		50,347		
Undiscovered (Paradox)					
	new fields	1,287	1,287	2,714	1,427
	tight nonassoc.	0	0	0	0
	tight associated	194	194	0	-194
	coalbed	0	0	0	0
	low btu	0	0	0	0
		1,481	1,481	2,714	1,233
Undiscovered - San Juan + Paradox					
	new fields	1,452	1,452	3,385	1,933
	tight nonassoc.	26,180	26,180	21,002	-5,178
	tight associated	194	194	0	-194
	coalbed	24,240	24,240	8,413	-15,827
	low btu	0	0	0	0
		52,066	52,066	32,800	-19,266
	control		51,828		

Note: the published EPCA undiscovered resource base is 238 Bcf low to USGS (see Uinta - Piceance)
Note: NPC includes Great Basin with Paradox

Summary of Undiscovered Resources - Four Basins

	USGS	EPCA	NPC	Difference
Powder River	16,486	16,486	21,650	5,164
Green River	84,590	84,590	86,994	2,404
Uinta-Piceance	21,424	21,424	30,751	9,327
San Juan (excluding Paradox)	50,585	50,585	30,086	-20,499
total of above basins	173,085	173,085	169,481	-3,604

Exhibit 1 (Continued)

Estimation of Federal vs Non-Federal Resources

Use of EPCA percentage to estimate federal portion of NPC
Undiscovered only, does not include proved or growth
Total Gas, Current tech, BCF

	2002 EPCA		2003 NPC	
	Bcf	%	Bcf	%
Powder River Basin				
Resource Base Breakout				
Federal	7,229	**43.8%**	9,482	**43.8%**
non-federal	9,258	56.2%	12,168	56.2%
total	16,487	100.0%	21,650	100.0%
Green River Basin				
Resource Base Breakout				
Federal	61,464	**72.7%**	63,245	**72.7%**
non-federal	23,126	27.3%	23,750	27.3%
total	84,590	100.0%	86,995	100.0%
Uinta Piceance				
Resource Base Breakout				
Federal	12,355	**57.0%**	17,528	**57.0%**
non-federal	9,306	43.0%	13,223	43.0%
total	21,661	100.0%	30,751	100.0%
San Juan				
Resource Base Breakout				
Federal	25,307	**48.8%**	14,832	**49.3%**
non-federal	26,521	51.2%	15,254	50.7%
total	51,828	100.0%	30,086	100.0%

(Slight difference due to NPC breakout of Paradox)

Exhibit 2. Estimation of Federal vs. Non-Federal Resources

the combined state and fee is the remaining portion of the resource.

C. Method Used to Compare Access Assessments

Exhibit 3 presents the current EPCA assessment of federal lands and compares this to the results of the NPC study. The EPCA assessment is categorized into months of delay, as well as statutory and administrative no access. The NPC study did not use the same classification system, so there are inherent difficulties with comparing the results. As mentioned above, the NPC evaluated a total no access using a nine-plus months of delay rule. The NPC also evaluated costs to determine the higher cost resource and EPCA did not. Despite these differences, it is possible to group the EPCA categories in a way in which the results can generally be compared to the NPC. This is the objective of the analysis in Exhibit 3.

Looking at the first page, EPCA data are shown for the San Juan/Paradox basin. Note that the EPCA resource base for the San Juan/Paradox is 25,307 billion cubic feet. *This does not include reserves or reserve growth*. This is an important distinction because in their report, the EPCA authors included proved reserves as "standard lease terms." When proved reserves are removed the percentage of resource subject to standard lease terms is lower. This can be a source of confusion in comparing the two studies. The only direct comparison is on an undiscovered resource basis. The EPCA study only evaluates federal lands, and so can only be compared to the federal lands portion of the NPC study.

This comparison is an effort to aggregate the EPCA and NPC categories/percentages to achieve rough equivalence. The first grouping is for "statutory no access." This equates to EPCA categories 1-3, which in the case of the San Juan is 4.7%. This 4.7% is also used directly in the NPC study.

The non-statutory conditions of approval no-access is defined here as the sum of EPCA categories 4 and 5 (0.3% for San Juan). This is approximately equivalent to the sum of NPC 10-12 months of "conditions of approval" seasonal restrictions (6.0% for San Juan).

The "leasing with restrictions" category is defined here as the sum of EPCA categories 6-8 (17.5%). This equates to the sum of the NPC 1-9 months of "conditions of approval" seasonal restrictions (10.6%).

The final category is labeled as "SLT (standard lease terms) plus CSU (controlled surface use)." This is the sum of EPCA categories 9-10 (77.5%). The addition of the CSU component to this grouping makes it equivalent to the current NPC zero months of seasonal restrictions (78.7%).

Note that EPCA did not analyze costs, so there can be no comparison to the cost results for NPC. The NPC's "high cost" resource is scattered within the last two categories in Exhibit 3, equivalent to EPCA categories 6-8 and 9-10.

D. Summary of Comparison for Federal Lands

The following is a summary of the comparison between EPCA and NPC undiscovered federal lands resources on the basis of aggregations shown in Exhibit 3.

1. San Juan

In the San Juan Basin, the standard lease terms resource fraction (SLT plus CSU) is quite similar at about 78%. The resource available with restrictions is lower in the NPC study (11% vs. 18%). The statutory no access is identical. The non-statutory no-access is higher in the NPC study (6% vs. <1%).

2. Uinta-Piceance

In the Uinta-Piceance Basin, the SLT/CSU resource fraction is lower in the NPC study (43% vs. 54%). The resource available with restrictions is higher in the NPC study (35% vs. 19%). The statutory no access is identical. The non-statutory no-access is lower in NPC (15% vs. 20%).

3. Green River

In the Green River Basin, the SLT/CSU resource fraction is much lower in the NPC study (26% vs. 58%). The resource available with restrictions is higher in the NPC study (38% vs. 30%). The statutory no access is identical. The non-statutory no-access is much higher in NPC (24% vs.1%).

4. Powder River

In the Powder River Basin, the SLT/CSU resource fraction is much lower in the NPC (24% vs. 66%). The resource available with restrictions is higher in the NPC (41% vs. 21%). The statutory no access is identical. The non-statutory no-access is much higher in NPC (24% vs. 3%).

E. Comparing All Land Types

Exhibit 4 presents a summary of all four basins, and compares EPCA and NPC access volumes for undiscovered the resource. The first two columns of the table show the EPCA federal land access data. The table shows that 62.7 % of the EPCA resource is considered SLT/CSU, 25.0 % is available with restrictions, and 12.4 % is no-access. The NPC federal access analysis indicates a SLT/CSU value of 36.1 %, while 34.1 % is available with restrictions and 29.7 % is no-access.

The right hand side of the table shows the non-federal portions of the NPC resource base and the corresponding access percentages using the same definitions. The non-federal resources were broken out into Indian and combined state and fee resource. Note in this series that the statutory no-access is always zero since it is only for federal lands. The NPC non-federal resource is generally characterized with a higher percentage of standard lease terms resource than the federal resource.

Comparison of EPCA and NPC Rockies Access Analysis

Comparison is for federal lands portion of resource since EPCA only evaluated federal.
Undiscovered only, does not include proved or growth
NPC breakout does not match final classification; This is an effort to match EPCA categories only.
Total Gas, Current technology, BCF

1. San Juan/Paradox Basin

EPCA category	EPCA Category Label	EPCA - Federal BCF	EPCA - Federal Percent of resource	NPC - Federal BCF	NPC - Federal Percent of resource	NPC - Indian BCF	NPC - Indian Percent of resource	NPC - State & Fee BCF	NPC - State & Fee Percent of resource	NPC - Total Undisc. BCF	NPC - Total Undisc. Percent of resource
1	No leasing (Statutory/Executive Order), (NLS)	540	2.1%								
2	No leasing (Administrative), (NLA/LUP)	1	0.0%								
3	No leasing (Administrative), (NLA)	647	2.6%								
4	Leasing, No Surface Occupancy (NSO)	67	0.3%								
5	Leasing, Cumulative Timing Limitations > 9 mos (TLs>9)	0	0.0%								
6	Leasing, Cumulative Timing Limitations 6-9 mos (TLs6-9)	402	1.6%								
7	Leasing, Cumulative Timing Limitations 3-6 mos (TLs3-6)	4,015	15.9%								
8	Leasing, Cumulative Timing Limitations < 3 mos (TLs<3)	10	0.0%								
9	Leasing, Controlled Surface Use (CSU)	1,789	7.1%								
10	Leasing, Standard Lease Terms (SLTs)	17,836	70.5%								
	Total federal	25,307	100.0%								
Comparison											
	Statutory no access (EPCA categories 1-3)	1,188	4.7%	697	4.7%	0	0.0%	0	0.0%	697	2.3%
	Non-statutory no access (EPCA categories 4-5) (NPC 10-12 months COA)	67	0.3%	890	6.0%	698	6.3%	263	6.3%	1,851	6.2%
	total no access	1,255	5.0%	1,587	10.7%	698	6.3%	263	6.3%	2,548	8.5%
	Leasing with restrictions (categories 6-8) (NPC 1-9 months COA)	4,427	17.5%	1,572	10.6%	1229	11.1%	270	6.5%	3,071	10.2%
	SLT plus CSU (EPCA categories 9-10) (NPC 0 months COA)	19,625	77.5%	11,673	78.7%	9145	82.6%	3649	87.3%	24,467	81.3%
		25,307	100.0%	14,832	100.0%	11,072	100.0%	4,182	100.0%	30,086	100.0%

Exhibit 3. Comparison of EPCA and NPC Rockies Access Analysis

2. Uinta - Piceance

EPCA category	EPCA Category Label	EPCA Unproved BCF	EPCA Percent of unproved	NPC - Federal BCF	NPC - Federal Percent of resource	NPC - Indian BCF	NPC - Indian Percent of resource	NPC - State & Fee BCF	NPC - State & Fee Percent of resource	NPC - Total Undisc. BCF	NPC - Total Undisc. Percent of resource
1	No leasing (Statutory/Executive Order), (NLS)	661	5.4%								
2	No leasing (Administrative), (NLA/LUP)	149	1.2%								
3	No leasing (Administrative), (NLA)	81	0.7%								
4	Leasing, No Surface Occupancy (NSO)	2,433	19.7%								
5	Leasing, Cumulative Timing Limitations > 9 mos (TLs>9)	0	0.0%								
6	Leasing, Cumulative Timing Limitations 6-9 mos (TLs6-9)	86	0.7%								
7	Leasing, Cumulative Timing Limitations 3-6 mos (TLs3-6)	1,652	13.4%								
8	Leasing, Cumulative Timing Limitations < 3 mos (TLs<3)	585	4.7%								
9	Leasing, Controlled Surface Use (CSU)	1,232	10.0%								
10	Leasing, Standard Lease Terms (SLTs)	5,475	44.3%								
	Total federal	12,355	100.0%								
Comparison											
	Statutory no access (EPCA categories 1-3)	891	7.2%	1,262	7.2%	0	0.0%	0	0.0%	1,262	4.1%
	Non-statutory no access (EPCA categories 4-5) (NPC 10-12 months COA)	2,433	19.7%	2,577	14.7%	292	15.8%	1,798	15.8%	4,667	15.2%
	total no access	3,324	26.9%	3,839	21.9%	292	15.8%	1,798	15.8%	5,929	19.3%
	Leasing with restrictions (categories 6-8) (NPC 1-9 months COA)	2,323	18.8%	6,187	35.3%	703	38.1%	2,543	22.4%	9,433	30.7%
	SLT plus CSU (EPCA categories 9-10) (NPC 0 months COA)	6,707	54.3%	7,502	42.8%	851	46.1%	7,037	61.8%	15,390	50.0%
		12,355	100.0%	17,528	100.0%	1,846	100.0%	11,378	100.0%	30,752	100.0%

Exhibit 3 (Continued)

3. Greater Green River

EPCA category	EPCA Category Label	EPCA Unproved BCF	EPCA Percent of unproved	NPC - Federal BCF	NPC - Federal Percent of resource	NPC - Indian BCF	NPC - Indian Percent of resource	NPC - State & Fee BCF	NPC - State & Fee Percent of resource	NPC - Total Undisc. BCF	NPC - Total Undisc. Percent of resource
1	No leasing (Statutory/Executive Order), (NLS)	4,598	7.5%								
2	No leasing (Administrative), (NLA/LUP)	702	1.1%								
3	No leasing (Administrative), (NLA)	2,046	3.3%								
4	Leasing, No Surface Occupancy (NSO)	175	0.3%								
5	Leasing, Cumulative Timing Limitations > 9 mos (TLs>9)	107	0.2%								
6	Leasing, Cumulative Timing Limitations 6-9 mos (TLs6-9)	4,055	6.6%								
7	Leasing, Cumulative Timing Limitations 3-6 mos (TLs3-6)	14,117	23.0%								
8	Leasing, Cumulative Timing Limitations < 3 mos (TLs<3)	104	0.2%								
9	Leasing, Controlled Surface Use (CSU)	2,076	3.4%								
10	Leasing, Standard Lease Terms (SLTs)	33,483	54.5%								
	Total federal	61,464	100.0%								
Comparison											
	Statutory no access (EPCA categories 1-3)	7,346	12.0%	7,589	12.0%	0		0	0.0%	7,589	8.7%
	Non-statutory no access (EPCA categories 4-5) (NPC 10-12 months COA)	282	0.5%	14,926	23.6%	0		6,365	26.8%	21,291	24.5%
	total no access	7,628	12.4%	22,515	35.6%	0		6,365	26.8%	28,880	33.2%
	Leasing with restrictions (categories 6-8) (NPC 1-9 months COA)	18,276	29.7%	24,223	38.3%	0		8,479	35.7%	32,702	37.6%
	SLT plus CSU (EPCA categories 9-10) (NPC 0 months COA)	35,559	57.9%	16,507	26.1%	0		8,906	37.5%	25,413	29.2%
		61,464	100.0%	63,245	100.0%	0		23,750	100.0%	86,995	100.0%

Exhibit 3 (Continued)

4. Powder River

EPCA category	EPCA Category Label	EPCA Unproved BCF	EPCA Percent of unproved	NPC - Federal BCF	NPC - Federal Percent of resource	NPC - Indian BCF	NPC - Indian Percent of resource	NPC - State & Fee BCF	NPC - State & Fee Percent of resource	NPC - Total Undisc. BCF	NPC - Total Undisc. Percent of resource
1	No leasing (Statutory/Executive Order), (NLS)	26	0.4%								
2	No leasing (Administrative), (NLA/LUP)	570	7.9%								
3	No leasing (Administrative), (NLA)	165	2.3%								
4	Leasing, No Surface Occupancy (NSO)	178	2.5%								
5	Leasing, Cumulative Timing Limitations > 9 mos (TLs>9)	1	0.0%								
6	Leasing, Cumulative Timing Limitations 6-9 mos (TLs6-9)	961	13.3%								
7	Leasing, Cumulative Timing Limitations 3-6 mos (TLs3-6)	545	7.5%								
8	Leasing, Cumulative Timing Limitations < 3 mos (TLs<3)	4	0.1%								
9	Leasing, Controlled Surface Use (CSU)	884	12.2%								
10	Leasing, Standard Lease Terms (SLTs)	3,896	53.9%								
	Total federal	7,229	100.0%								
Comparison											
	Statutory no access (EPCA categories 1-3)	761	10.5%	996	10.5%	0	0.0%	0	0.0%	996	4.6%
	Non-statutory no access (EPCA categories 4-5) (NPC 10-12 months COA)	179	2.5%	2,314	24.4%	59	27.2%	3,137	26.3%	5,510	25.5%
	total no access	940	13.0%	3,310	34.9%	59	27.2%	3,137	26.3%	6,506	30.1%
	Leasing with restrictions (categories 6-8) (NPC 1-9 months COA)	1,510	20.9%	3,869	40.8%	99	45.6%	5,503	46.1%	9,471	43.7%
	SLT plus CSU (EPCA categories 9-10) (NPC 0 months COA)	4,779	66.1%	2,304	24.3%	59	27.2%	3,310	27.7%	5,673	26.2%
		7,229	100.0%	9,483	100.0%	217	100.0%	11,950	100.0%	21,650	100.0%

Exhibit 3 (Continued)

Summary of Access Comparison for EPCA and NPC Rockies - Four Basins Combined

Comparison on Equivalent Basis

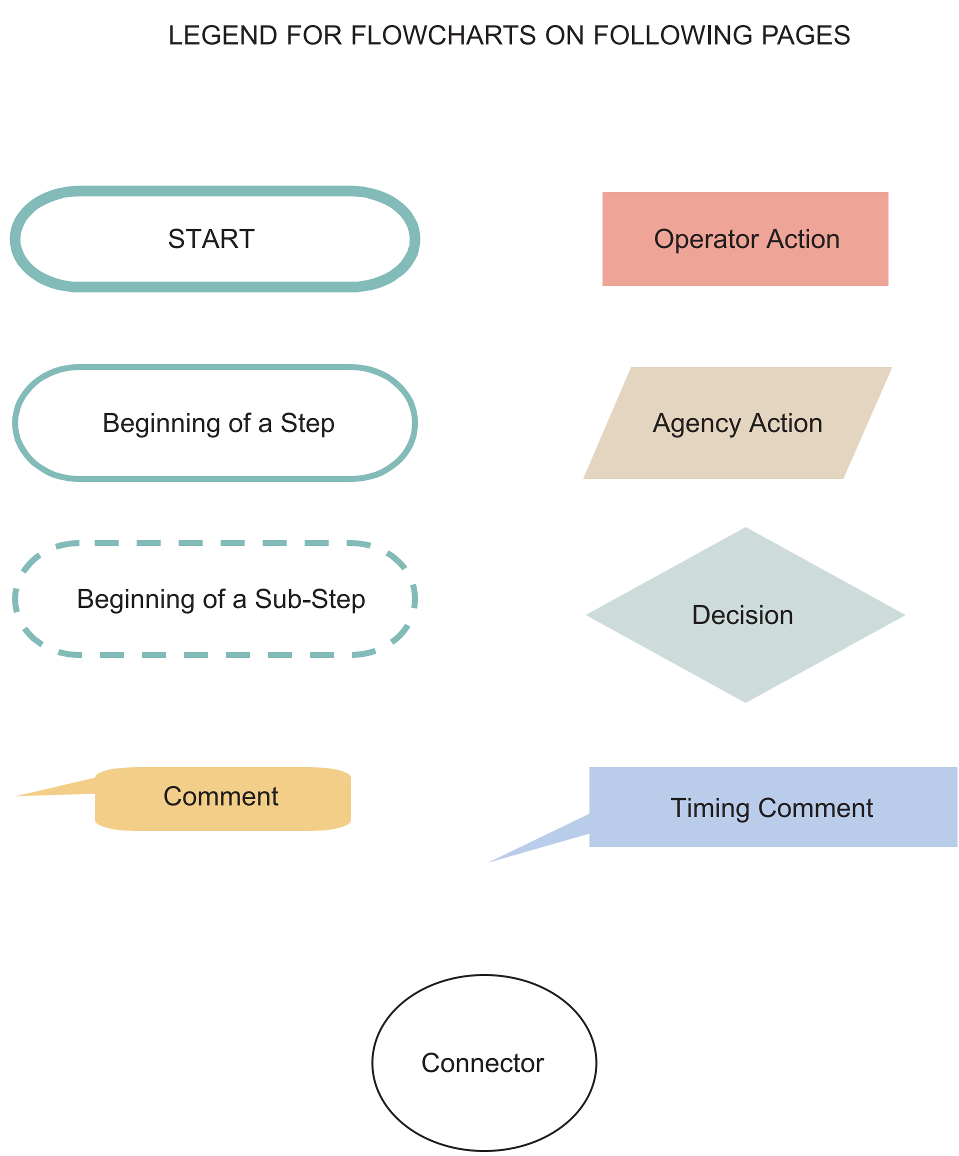
San Juan, Green River, Uinta-Piceance, and Powder River

	EPCA Federal		EPCA Non-federal	EPCA Total	NPC - Federal		NPC - Indian		NPC - State & Fee		NPC - Total Undisc.	
	BCF	Percent of resource	BCF	BCF	BCF	Percent of resource	BCF	Percent of resource	BCF	Percent of resource	BCF	Percent of resource
Statutory no access (EPCA categories 1-3)	10,186	9.6%	not evaluated		10,544	10.0%	0	0.0%	0	0.0%	10,544	6.2%
Non-statutory no access (EPCA categories 4-5) (NPC 10-12 months COA)	2,961	2.8%	not evaluated		20,707	19.7%	1,049	8.0%	11,563	22.6%	33,319	19.7%
total no access	13,147	12.4%			31,251	29.7%	1,049	8.0%	11,563	22.6%	43,863	25.9%
Leasing with restrictions (categories 6-8) (NPC 1-9 months COA)	26,536	25.0%	not evaluated		35,851	34.1%	2,031	15.5%	16,795	32.8%	54,677	32.3%
SLT plus CSU (EPCA categories 9-10) (NPC 0 months COA)	66,671	62.7%	not evaluated		37,986	36.1%	10,055	76.6%	22,902	44.7%	70,943	41.9%
	106,354	100.0%	68,212	174,566	105,088	100.0%	13,135	100.0%	51,260	100.0%	169,483	100.0%

Exhibit 4. Summary of Access Comparison for EPCA and NPC Rockies – Four Basins Combined

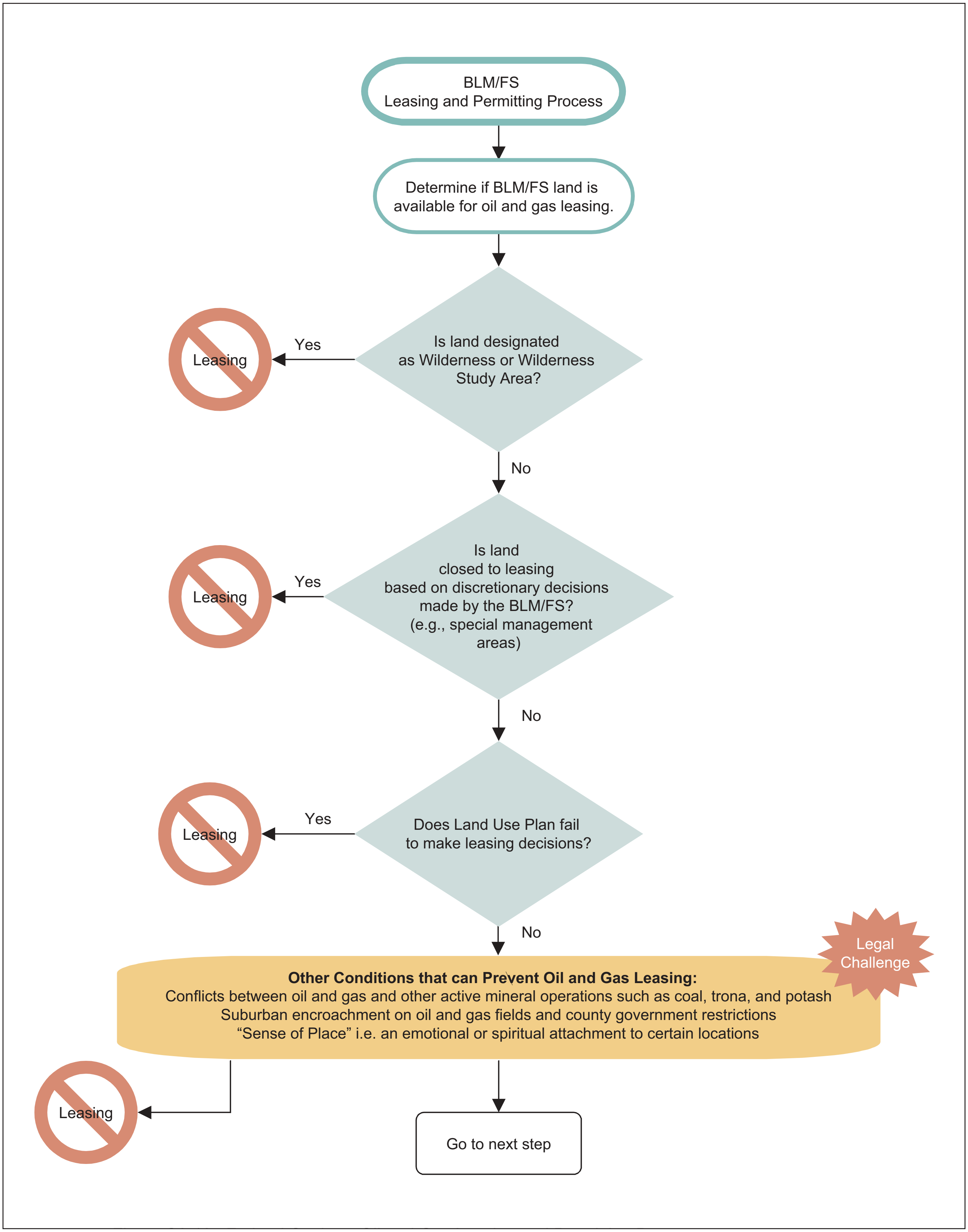
V. Flowcharts of Federal Onshore Oil and Gas Leasing and Permitting Process

The diagrams on the following pages are flowcharts detailing the leasing and permitting process for onshore federal lands.

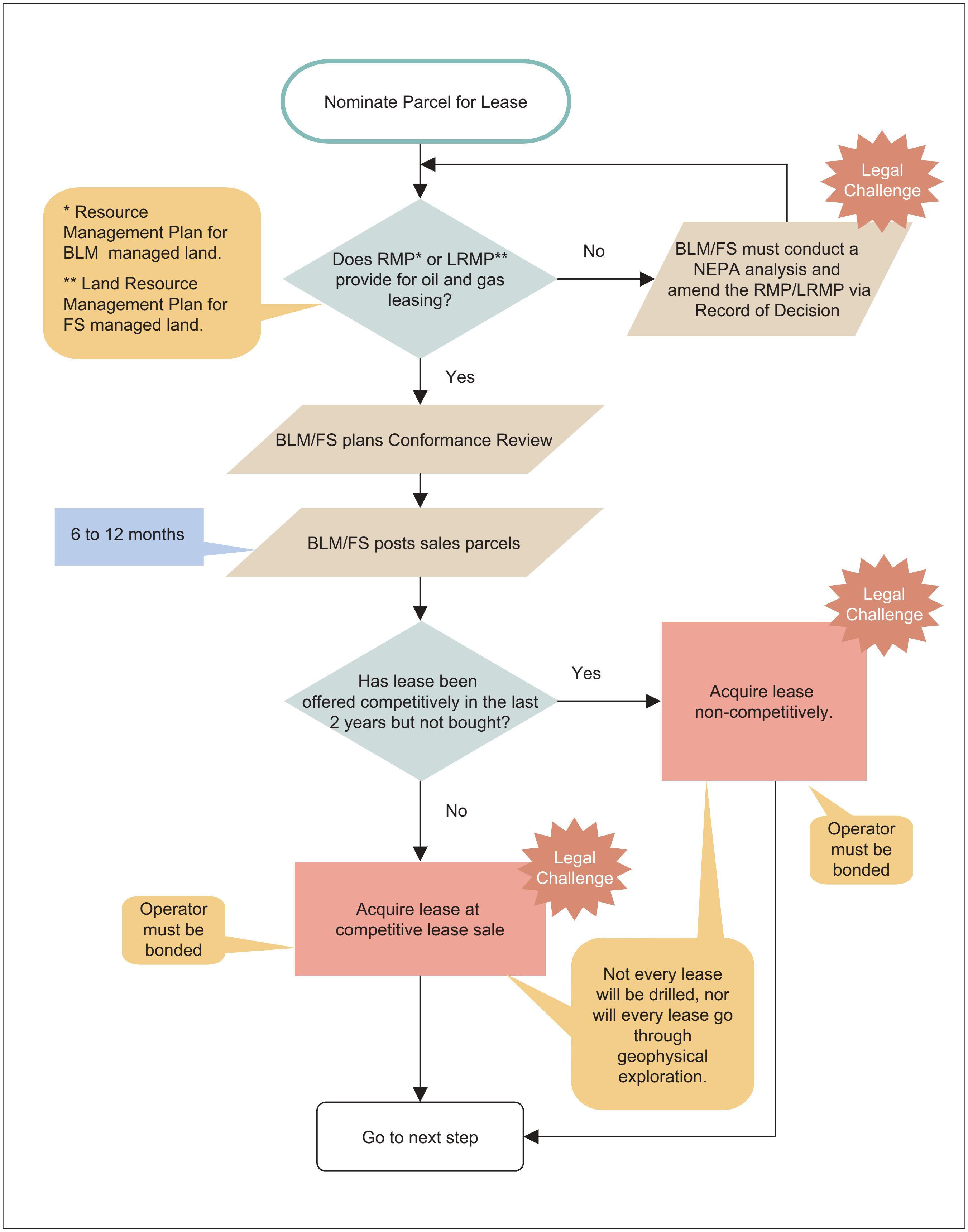


Source: American Petroleum Institute.

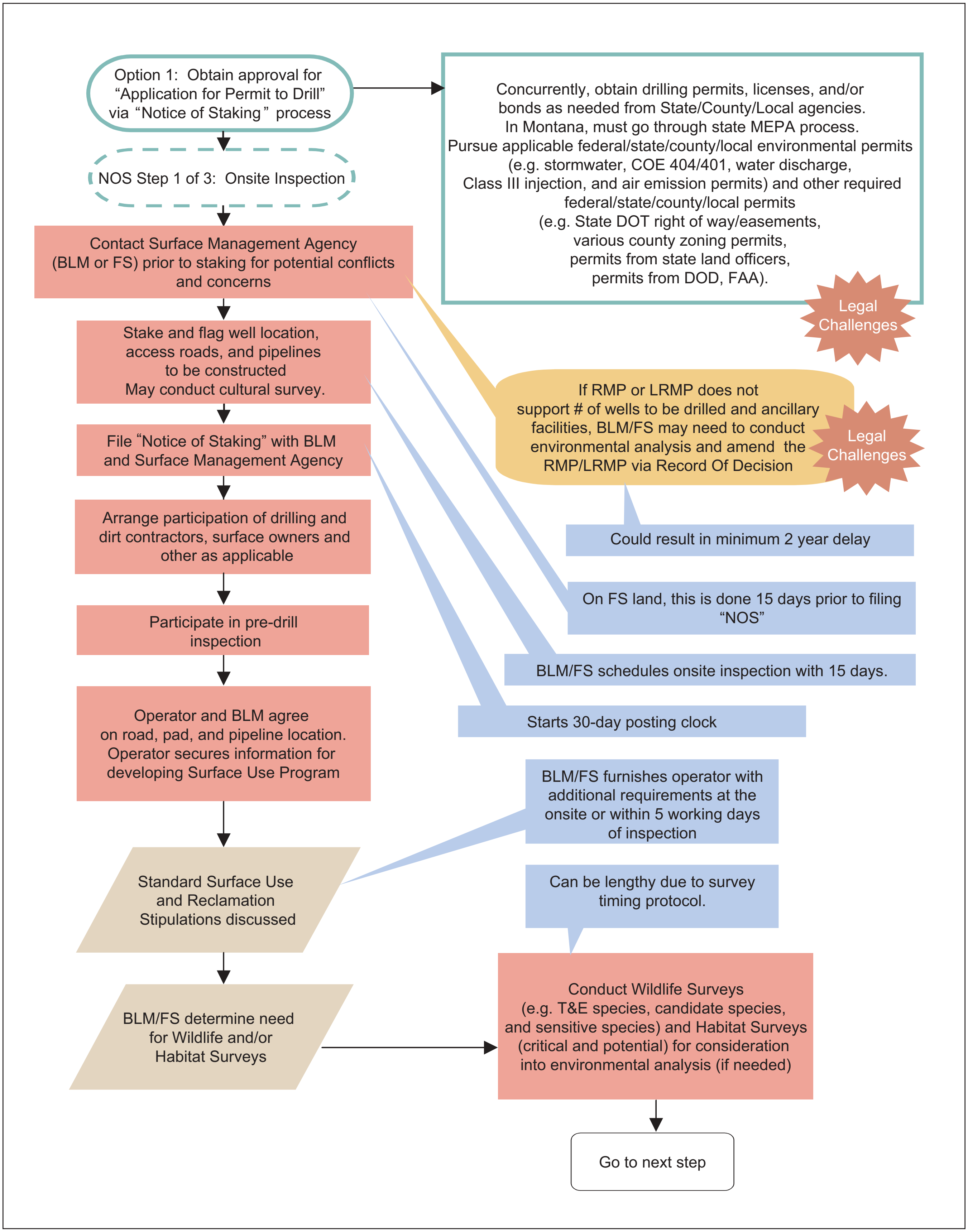
Federal Onshore Oil and Gas Leasing and Permitting Process



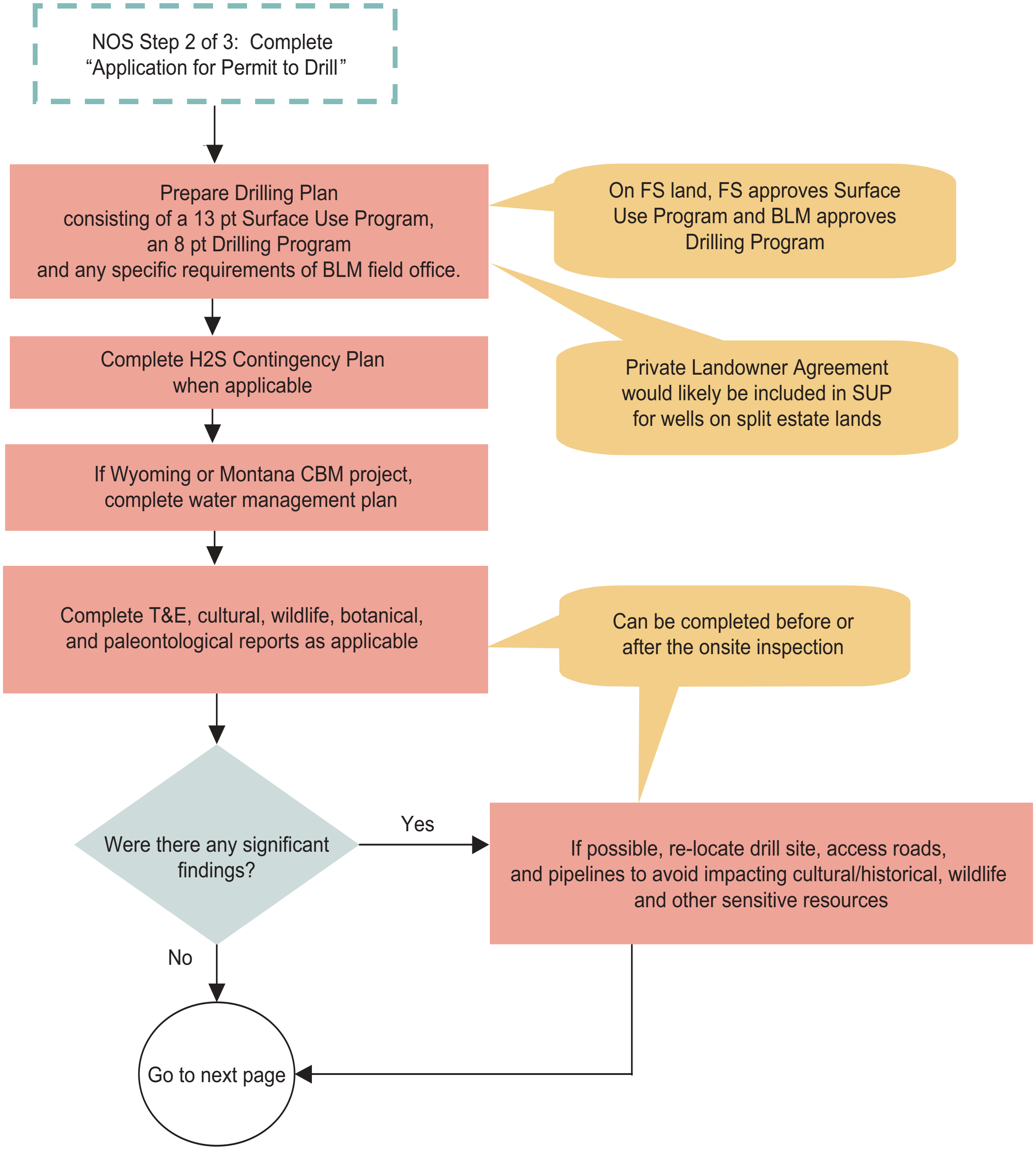
Federal Onshore Oil and Gas Leasing and Permitting Process (Continued)



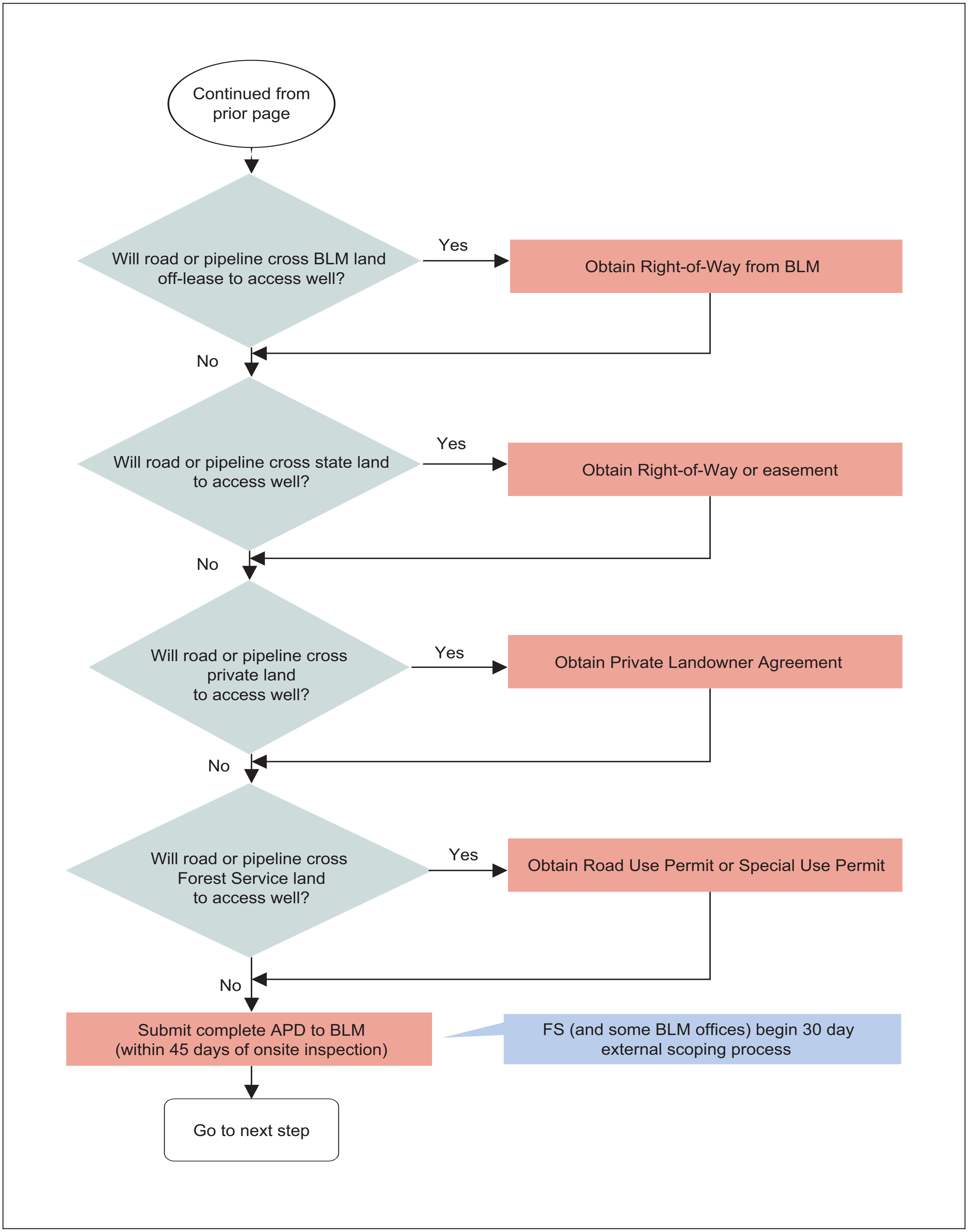
Federal Onshore Oil and Gas Leasing and Permitting Process (Continued)



Federal Onshore Oil and Gas Leasing and Permitting Process (Continued)



Federal Onshore Oil and Gas Leasing and Permitting Process (Continued)



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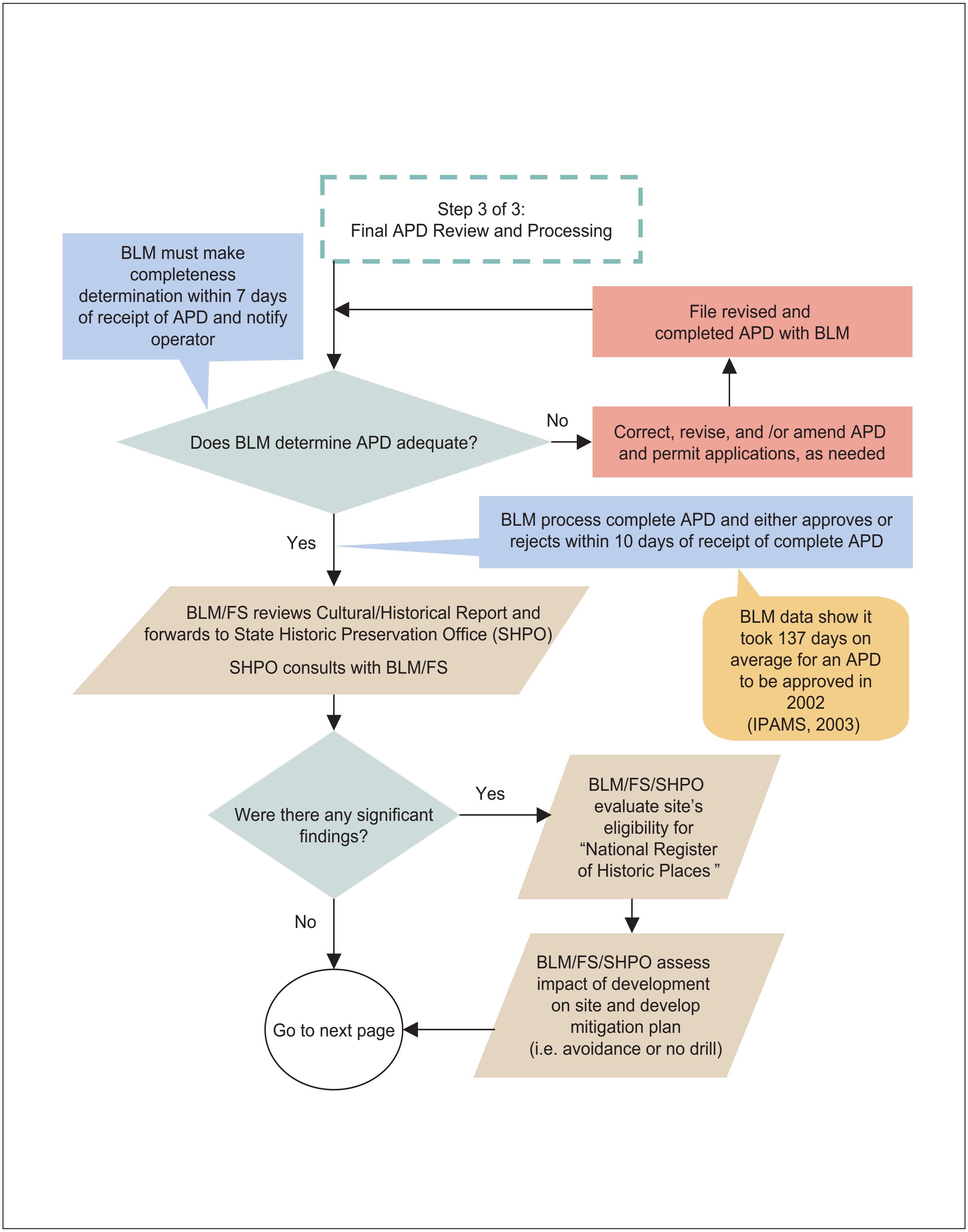

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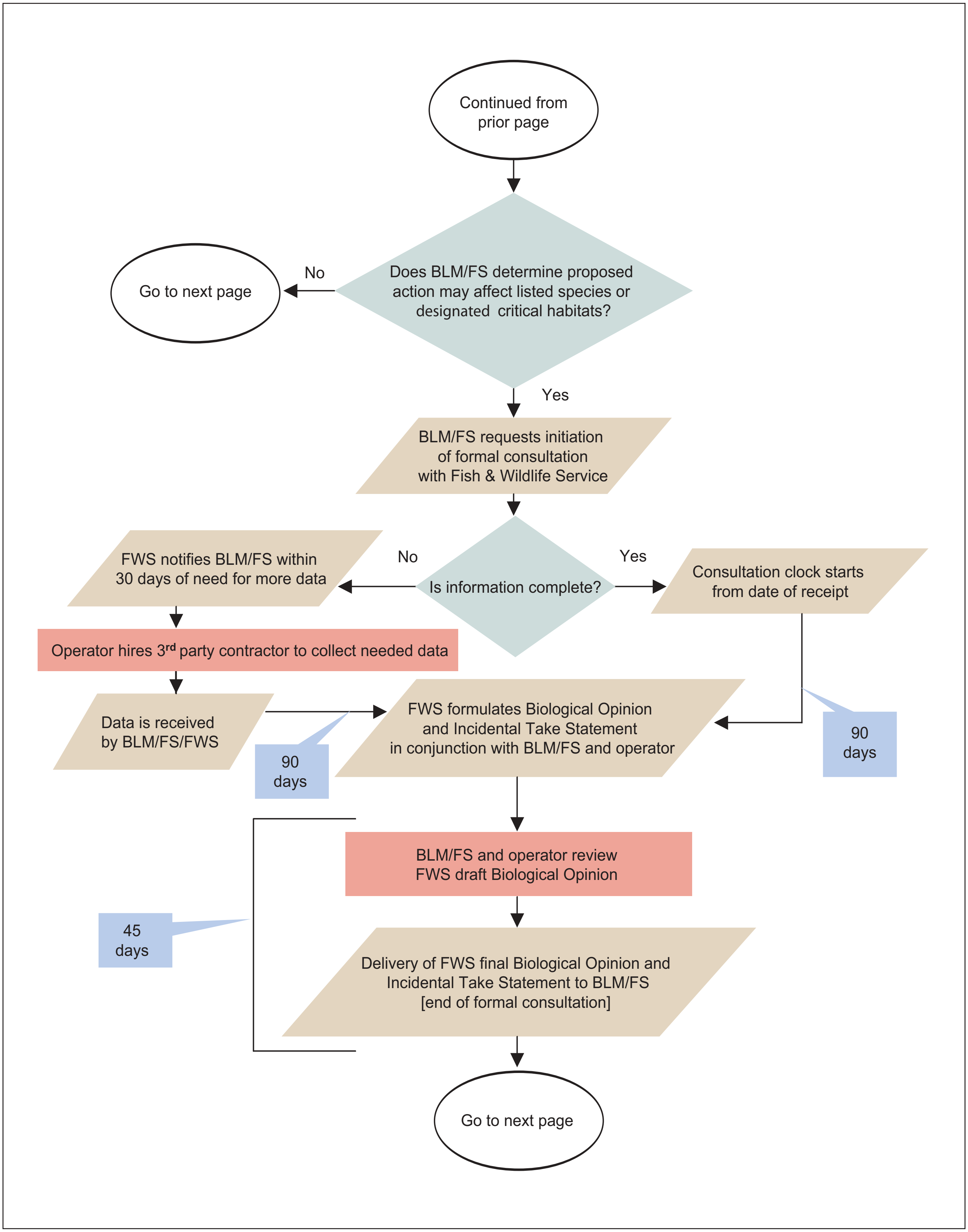
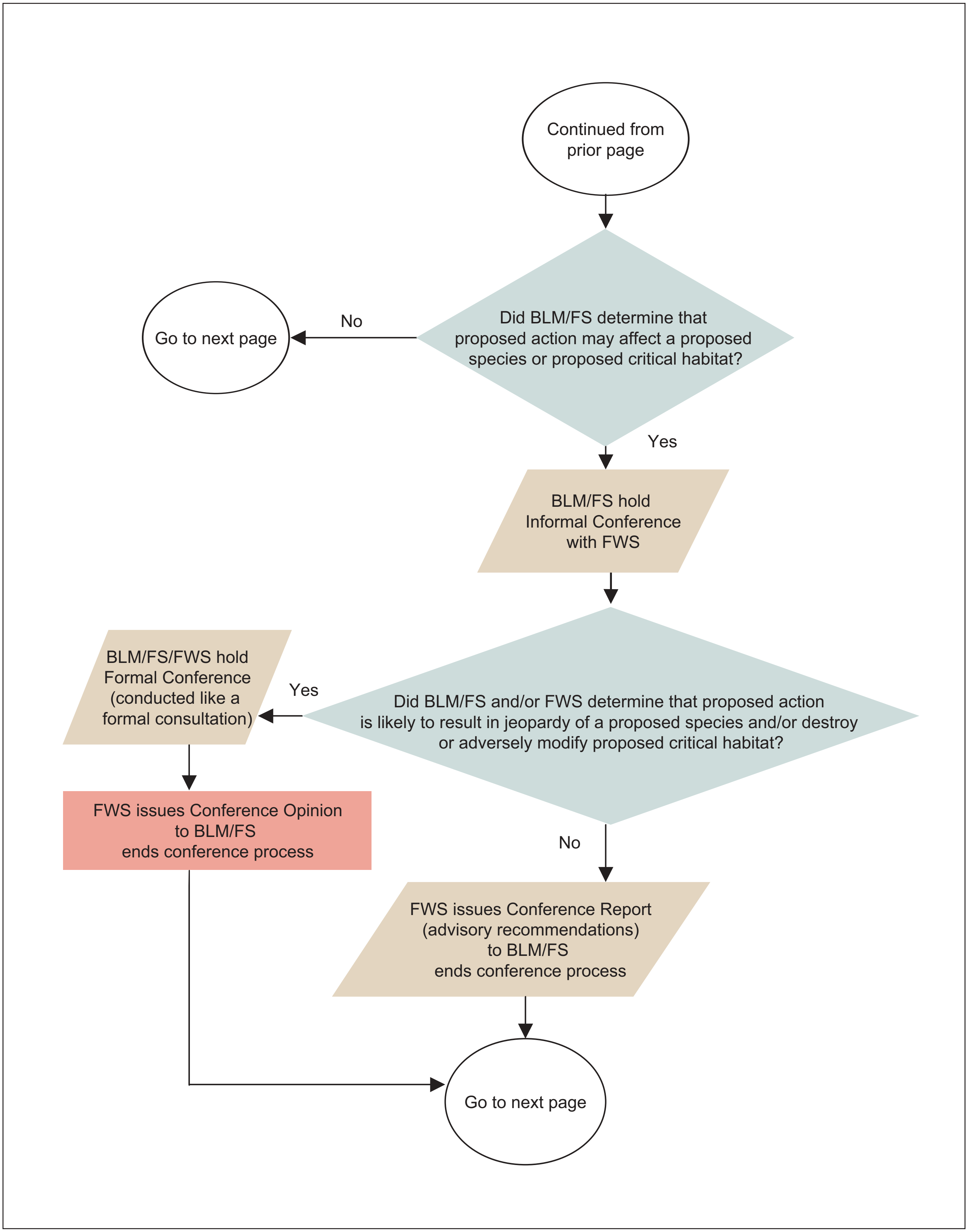
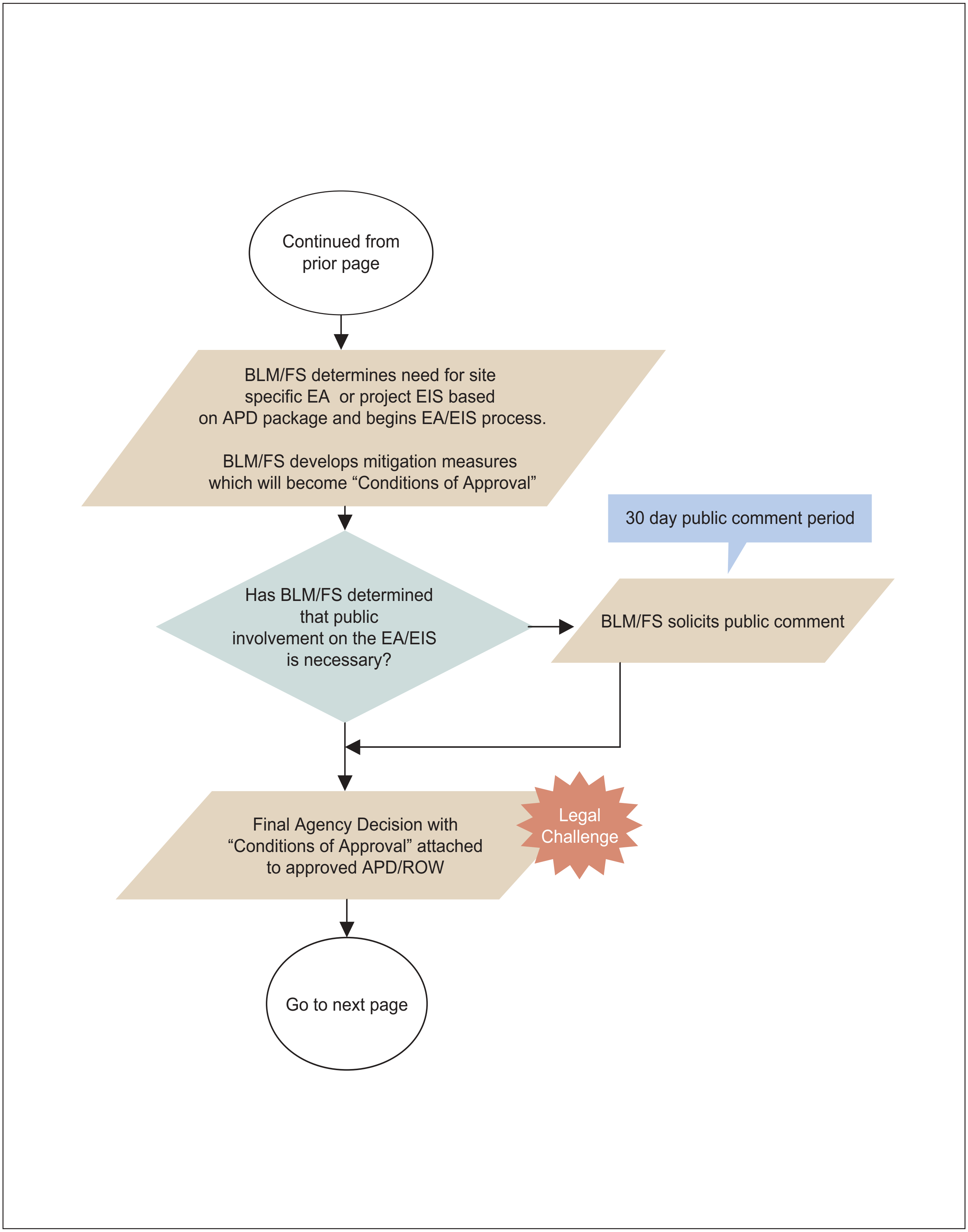


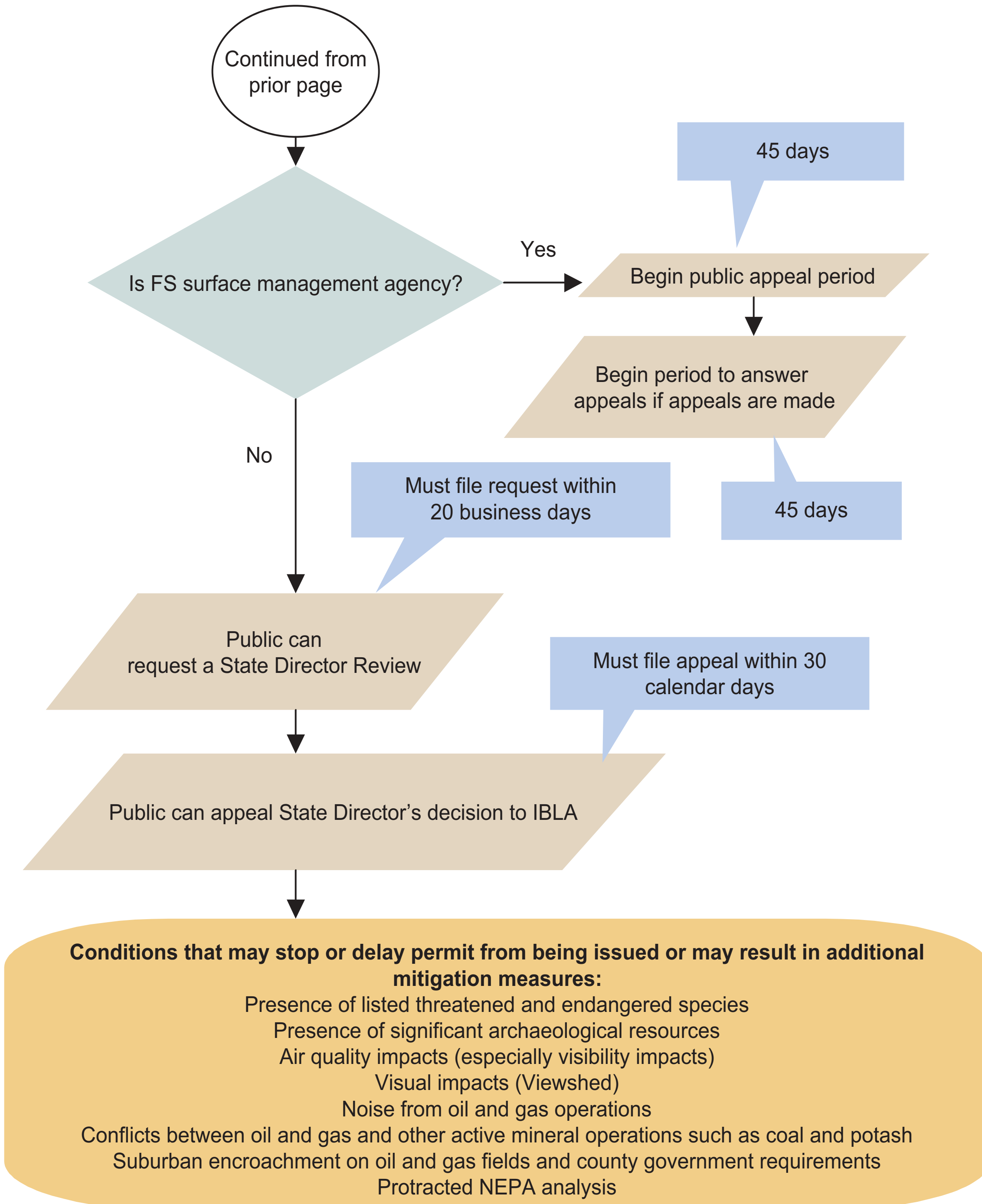
Federal Onshore Oil and Gas Leasing and Permitting Process (Continued)



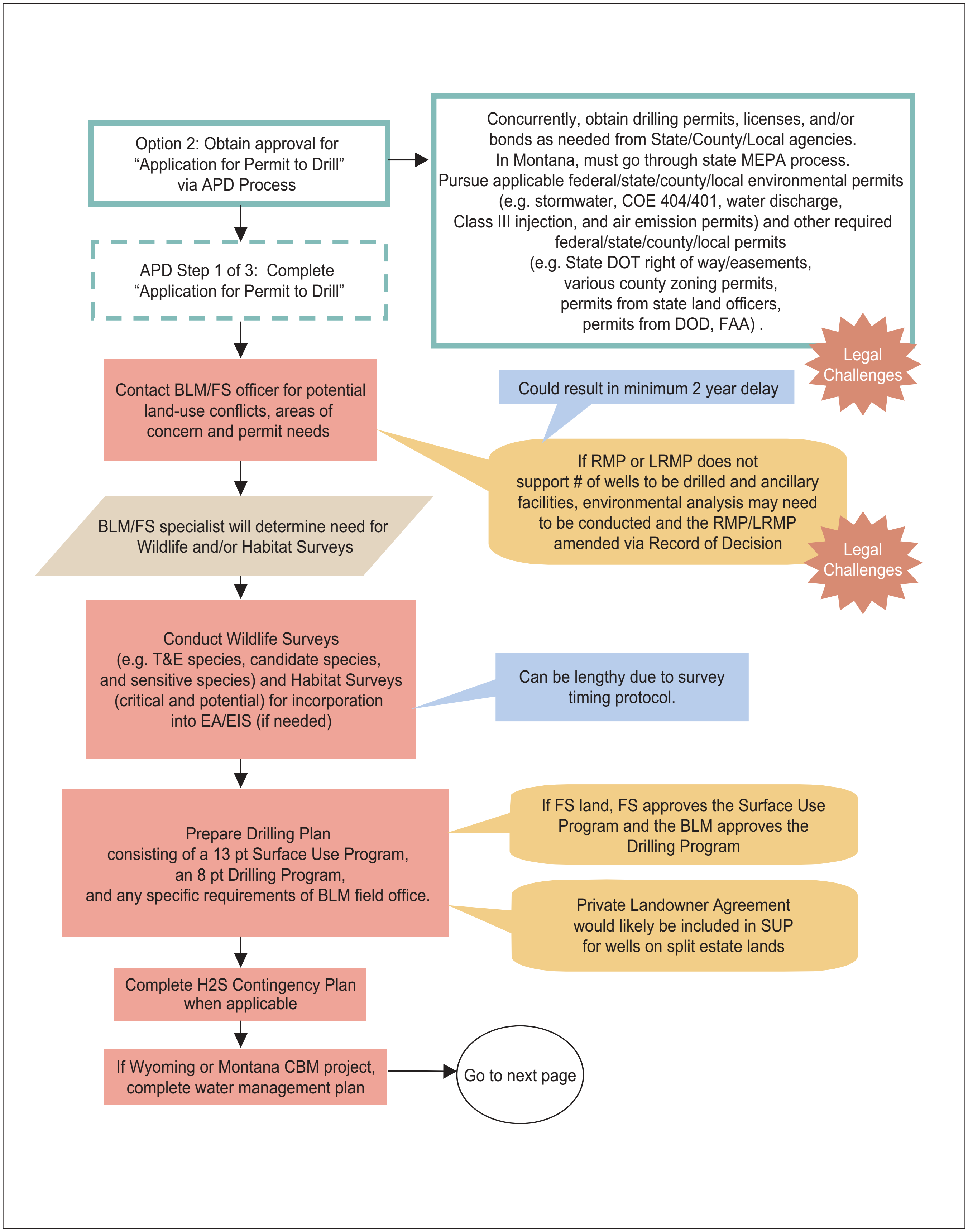
Federal Onshore Oil and Gas Leasing and Permitting Process (Continued)



Federal Onshore Oil and Gas Leasing and Permitting Process (Continued)



Federal Onshore Oil and Gas Leasing and Permitting Process (Continued)



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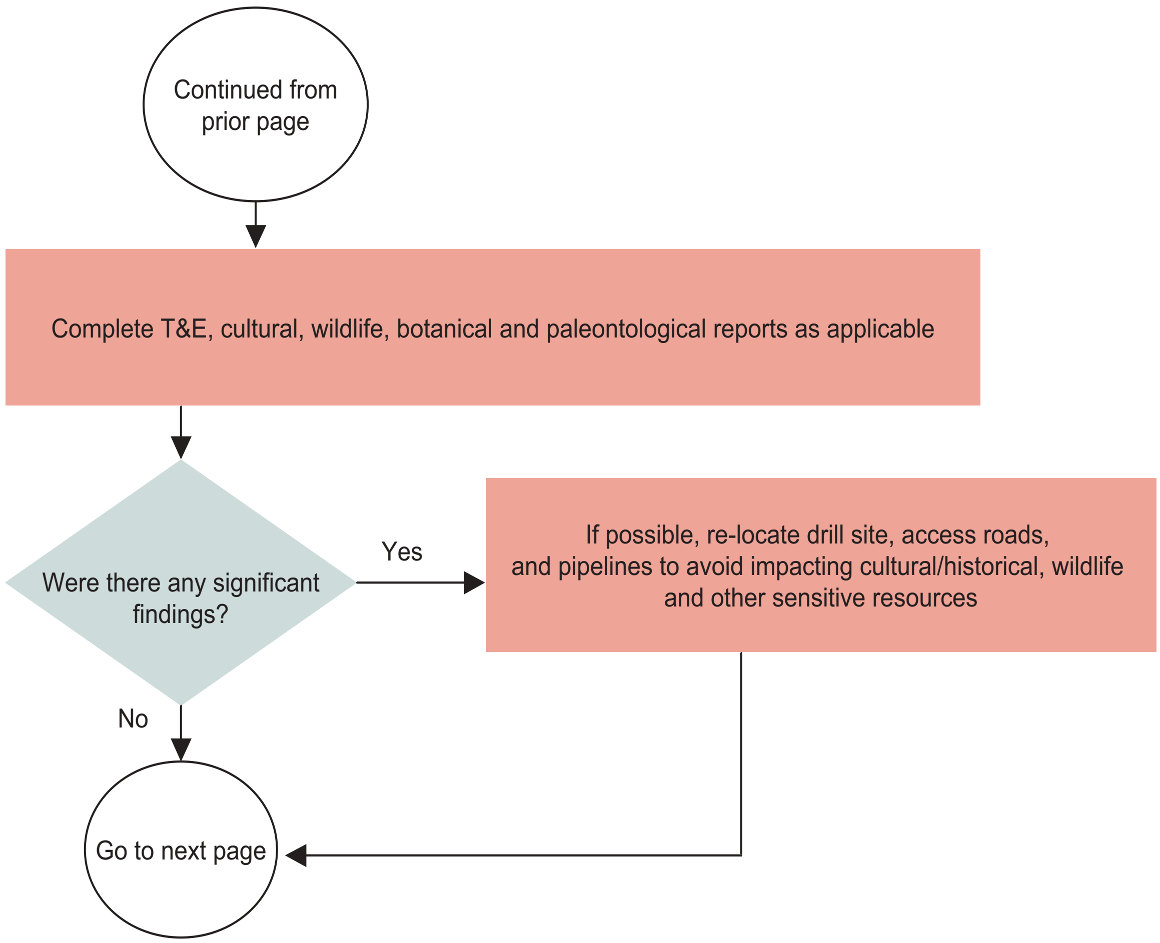
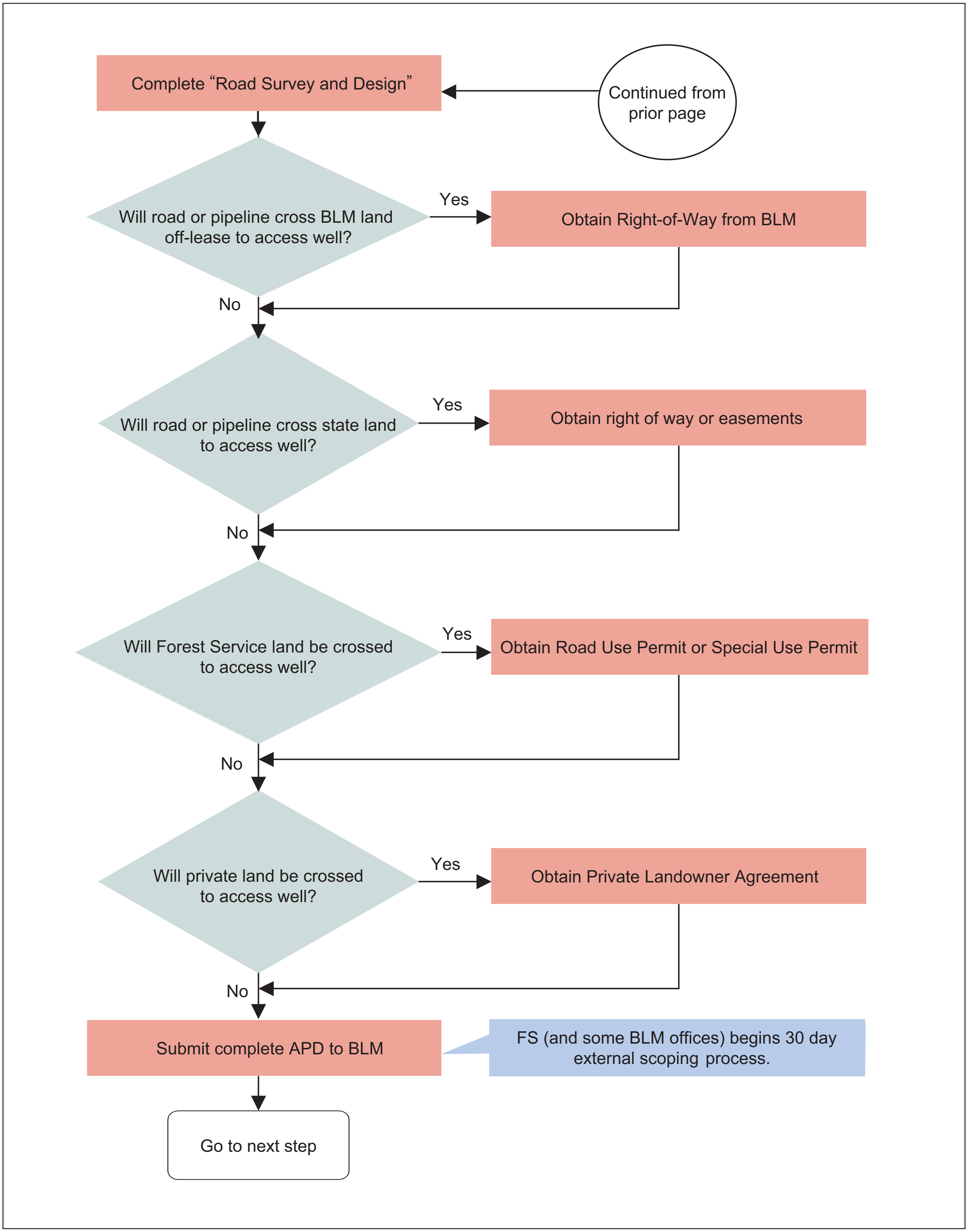
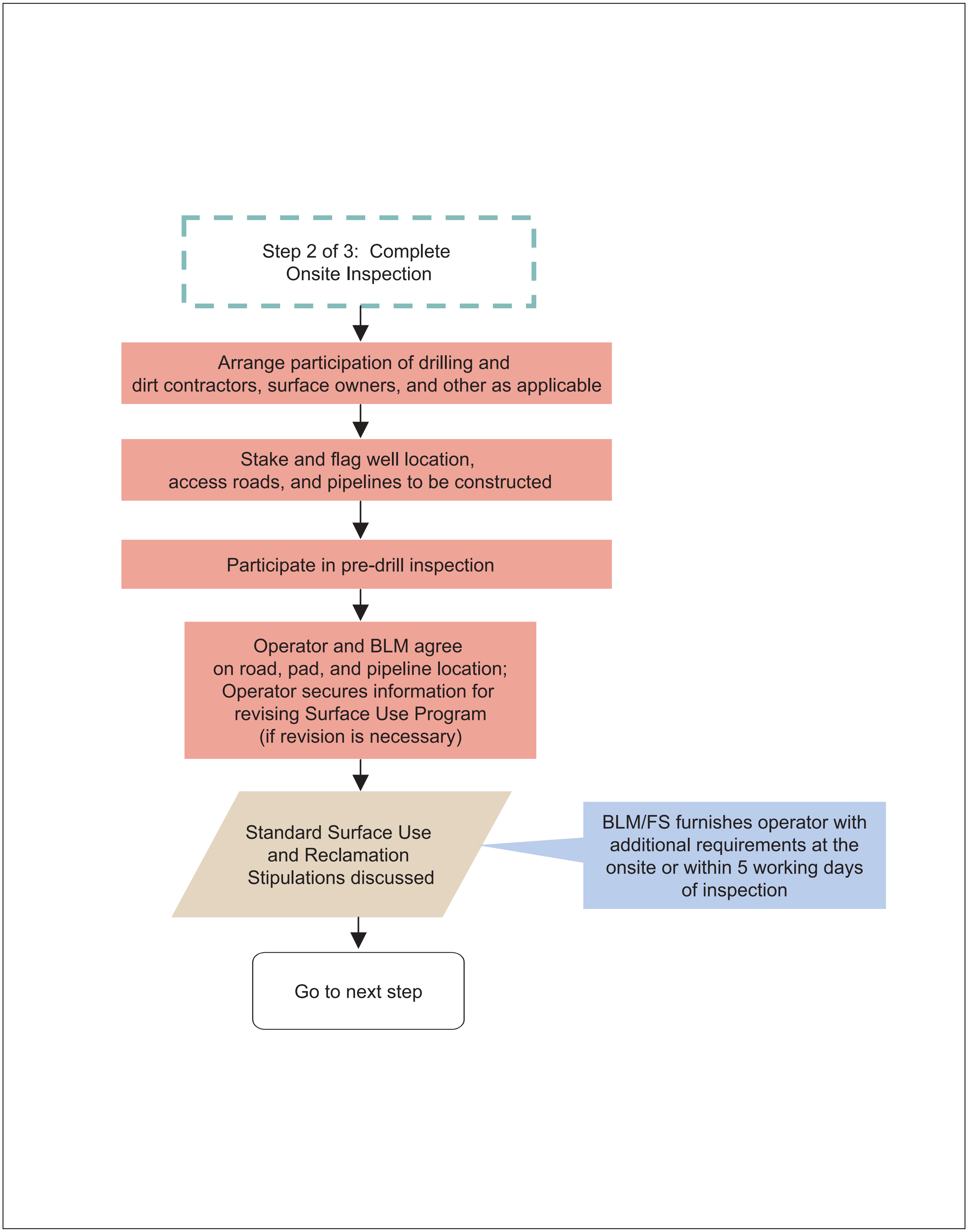


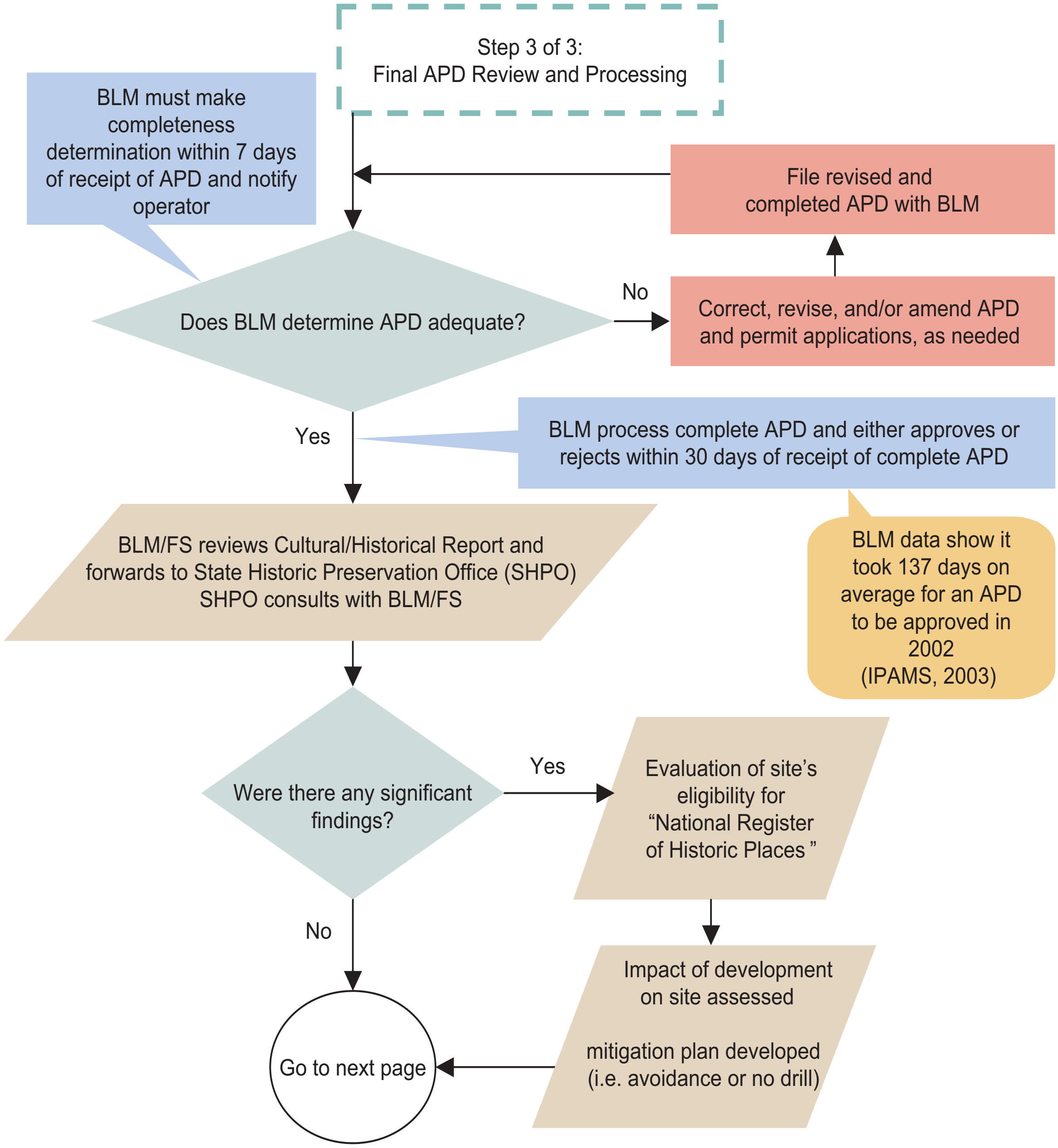
Federal Onshore Oil and Gas Leasing and Permitting Process (Continued)



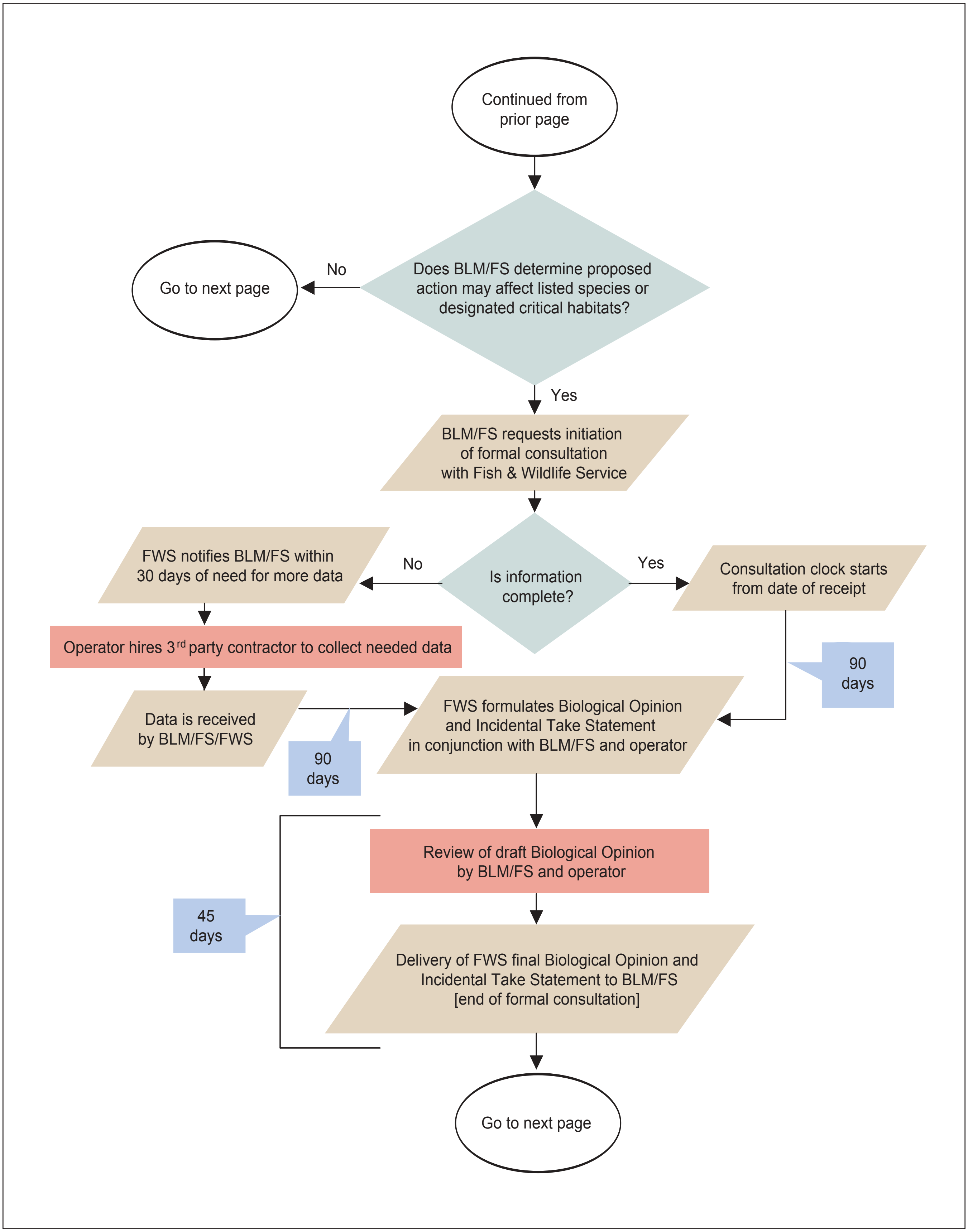
Federal Onshore Oil and Gas Leasing and Permitting Process (Continued)



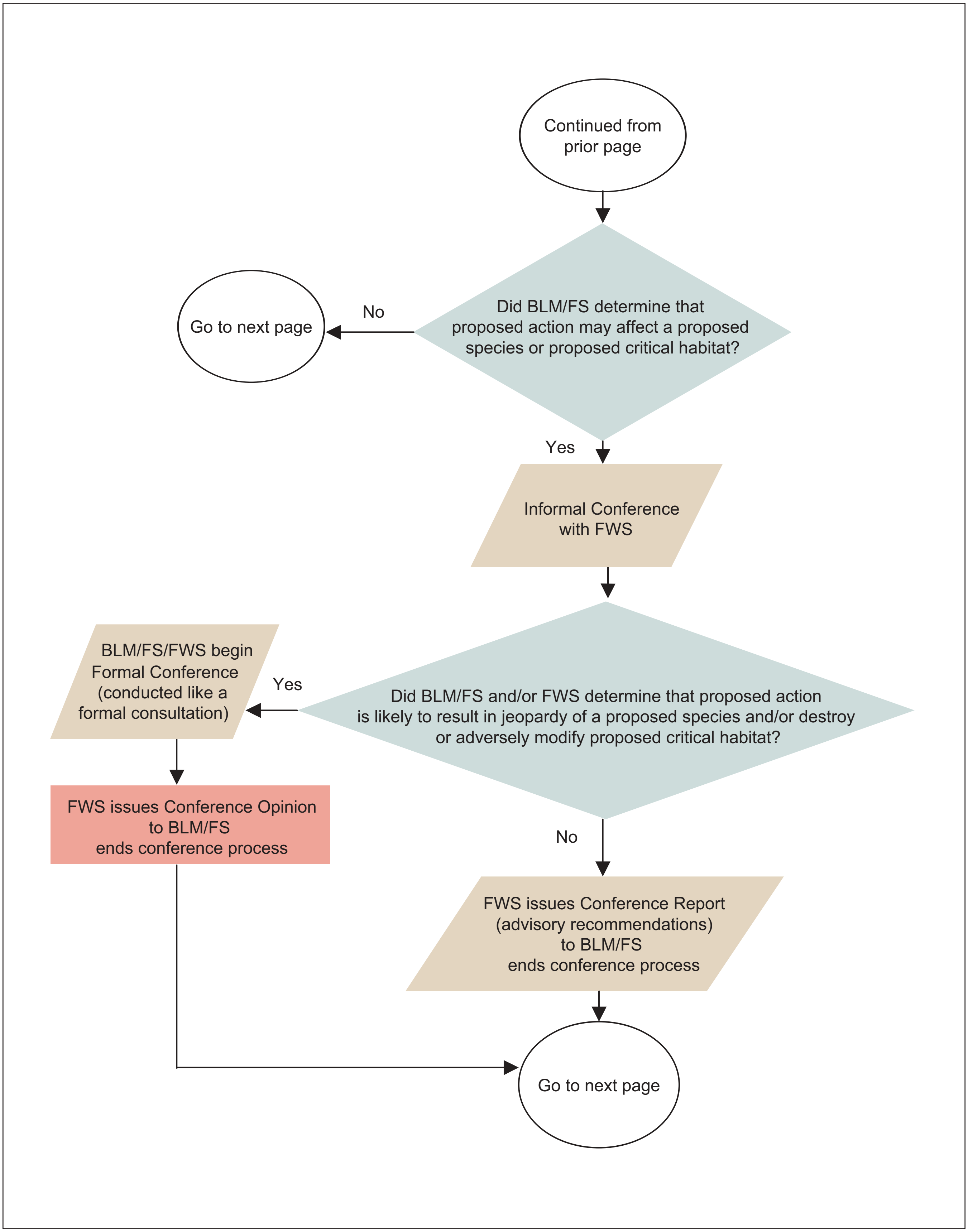
Federal Onshore Oil and Gas Leasing and Permitting Process (Continued)



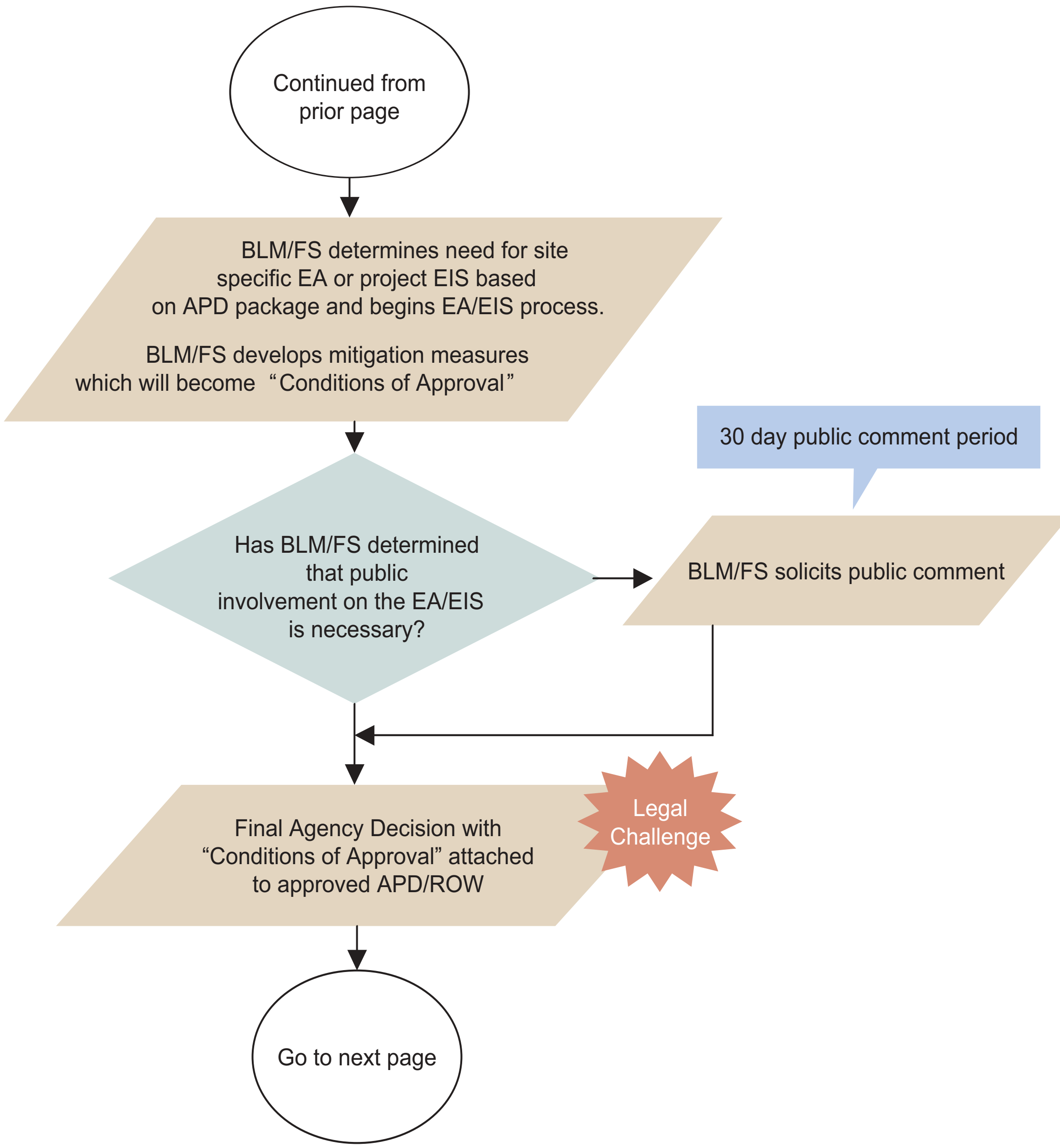
Federal Onshore Oil and Gas Leasing and Permitting Process (Continued)



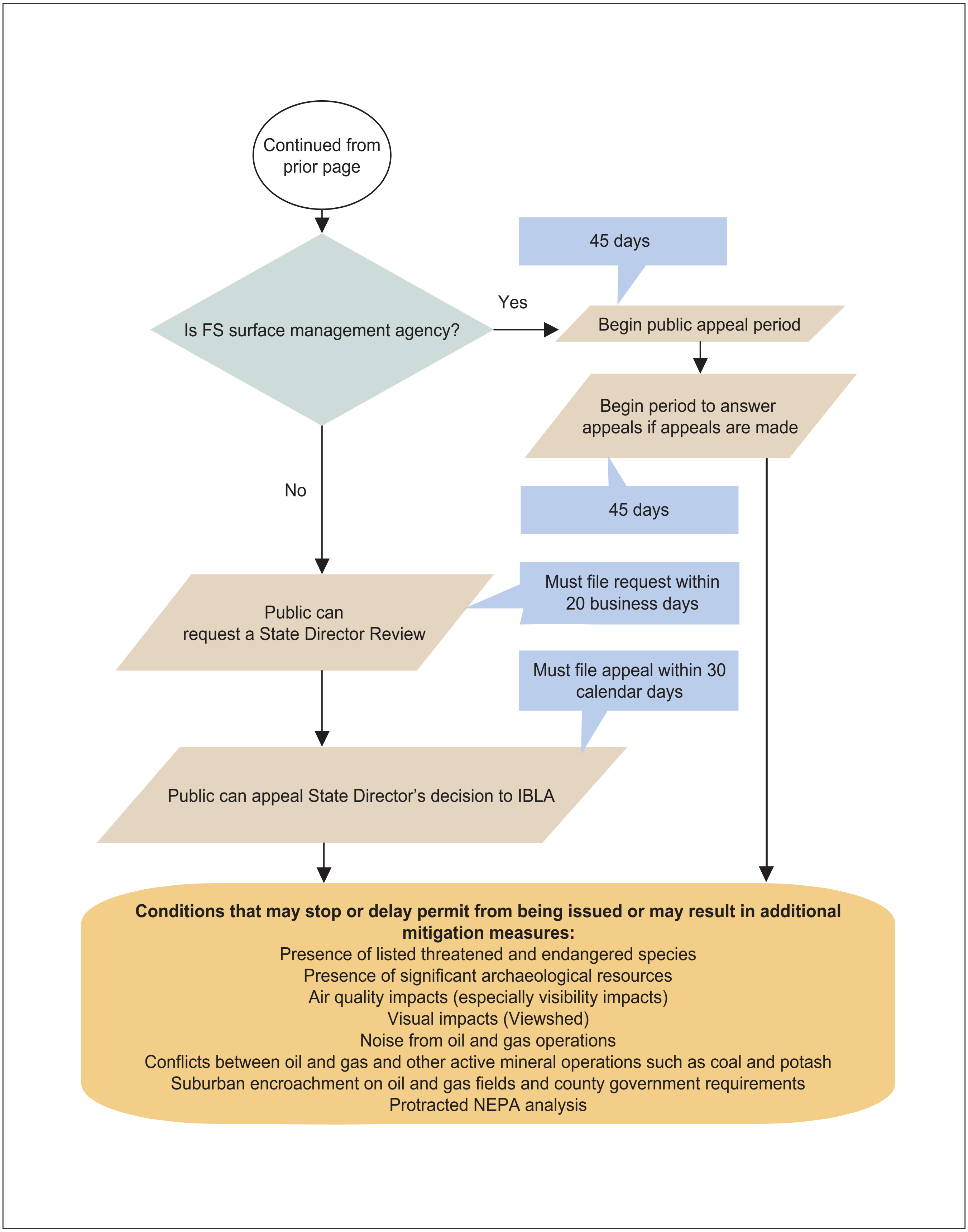
Federal Onshore Oil and Gas Leasing and Permitting Process (Continued)



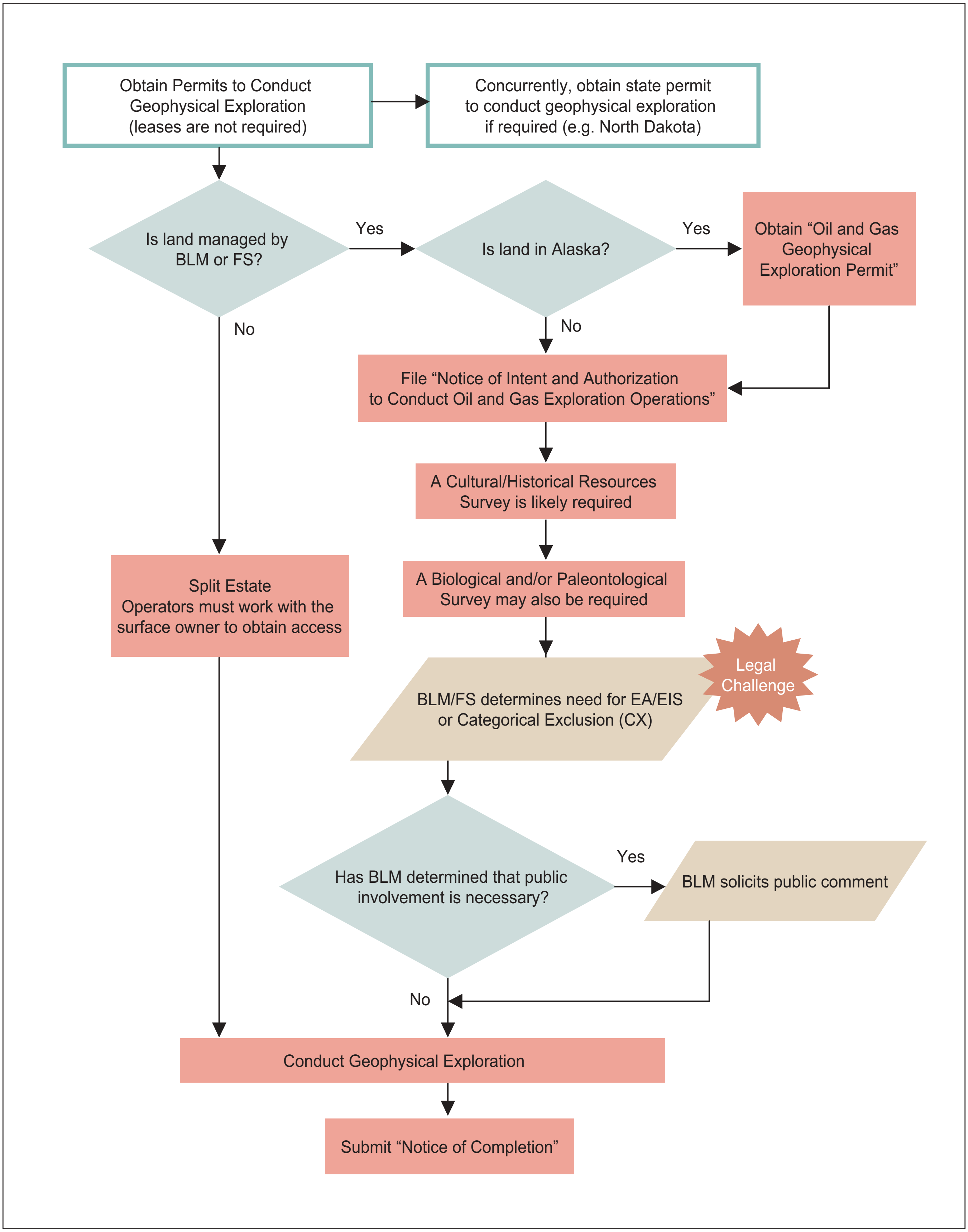
Federal Onshore Oil and Gas Leasing and Permitting Process (Continued)



Federal Onshore Oil and Gas Leasing and Permitting Process (Continued)



Federal Onshore Oil and Gas Leasing and Permitting Process (Continued)



Federal Onshore Oil and Gas Leasing and Permitting Process (Continued)

VI. Access Onshore Conditions of Approval Tables

The NPC has created a set of tables in Excel format documenting Rocky Mountain access restrictions by basin. Details are provided for federal and non-federal lands, and with and without reserve appreciation. Also included is a table summarizing North American access restrictions including volumes impacted by the offshore moratoria.

Please refer to the Data CD for these tables.

VII. Survey Protocols and Costs

A. NPC Survey Protocols for Wildlife Species

1. General Raptors (Powder River, Green River, Uinta-Piceance, and San Juan Basins)

The activity status of all known raptor nests, as determined from the records of management agencies (BLM, USFS, state game and fish) are systematically checked over the entire project area from a helicopter during a spring/early summer aerial survey. During this survey, a search for previously undiscovered nests is also made. Depending on agency requirements, a ground survey might also be made to verify the species of raptor utilizing active nests. Several species of owls require specialized survey techniques suited to the habits of the species. For example, searches for active burrowing owls must be conducted from the ground and usually consist of utilizing ATVs to drive transect lines through prairie dog colonies to look for owls and owl castings.

2. Greater Sage-Grouse (Powder River, Green River, and Uinta-Piceance Basins)

Dawn surveys are conducted over the entire project area from fixed-wing aircraft to search for and identify the locations of active leks. Such leks are determined by the presence of displaying male birds whose white breasts show up well from the air. Depending on agency requirements, ground surveys to determine the numbers of males on active leks may also be required. These surveys are also conducted at dawn.

3. Gunnison Sage-Grouse (Uinta-Piceance Basin)

Survey requirements are identical to those described for the greater sage-grouse. Other special and specific agency requirements may be imposed.

4. Sharp-Tailed Grouse (Powder River, Green River, Uinta-Piceance, and San Juan Basins)

Dawn ground surveys are conducted within suitable habitats to listen and look for displaying male grouse on leks. Depending on agency requirements, ground surveys to determine the numbers of males on active leks may also be required. These surveys are also conducted at dawn.

5. Big Game (Powder River, Green River, Uinta-Piceance, and San Juan Basins)

Since big game habitats and numbers are usually provided by the respective state game and fish departments, the collection of this kind of data is generally not required. Surveys that may be required consists of field checks to determine whether or not big game species are present on the crucial/critical winter or parturition ranges where they are normally expected to be during the respective winter and parturition periods. If the winter/spring period is mild and animals are not concentrated in their normal patterns on the crucial/critical ranges, it presents the possibility that the management agency in charge will allow an exception to the crucial/critical habitat timing stipulation and allow construction/drilling activities to proceed. In order to justify such exceptions, it is often necessary for the operator to hire a consultant to survey the critical/crucial habitats to determine the density and locations of big game animals. Such surveys consist of inspection of the crucial/critical habitats from the air or ground. It these surveys determine that big game animals are not in the vicinity of the operators' proposed actions, it is reasonable for the operator to request an exception to the timing exclusions placed on the lease so that drilling and construction activities can proceed earlier than would otherwise have been possible. Under winter conditions, it is often more expedient to overfly the crucial/critical habitats in question to determine animal numbers and distribution. In other cases, it may be reasonable to conduct such surveys from the ground using standard 4-wheel drive vehicles or snow machines.

6. Threatened & Endangered Species

a. Grizzly Bear (Green River Basin)

A data base for this species sufficient for EIS and BA analyses usually exists and no surveys are required. This usually consists of collecting and integrating data from existing sources so that the interagency grizzly bear model can be run to quantify potential impacts and determine appropriate mitigation efforts.

b. Canada Lynx (Green River, Uinta-Piceance, and San Juan Basins)

A data base for this species sufficient for EIS and BA analyses usually exists and no surveys are required. However, in areas where lynx occurrence data are not available, on the ground winter surveys for lynx and prey species tracks may be required. Such surveys consist of snowshoe transects conducted within a 1/2-mile radius of the proposed actions.

c. Gray Wolf (Green River, Uinta-Piceance, and San Juan Basins)

A data base for this species sufficient for EIS and BA analyses usually exists, and no surveys are required. However, in areas where wolf occurrence data are not available, on the ground and/or aerial surveys for wolf occurrence and sign may be required. Such surveys consist of aerial flights to search for wolf occurrence or wolf-killed carcasses and/or ground surveys for tracks, scat, and wolf-killed carcasses. Ground surveys may also include howling surveys where in surveyors listen for and produce wolf howling to determine presence of this species.

d. Black-Footed Ferret (Powder River, Green River, Uinta-Piceance, and San Juan Basins)

According to FWS guidelines, black-footed ferret surveys must be conducted on prairie dog colonies with 8 or more burrows per acre that are large enough to support black-footed ferrets (black-tailed prairie dog colonies 80 acres or larger in size; and white-tailed prairie dog colonies 200 acres or larger in size) to determine the presence or absence of black-footed ferrets. These surveys can be conducted during the summer between July 1 and October 31 and during the winter between December 1 and March 31. Summer surveys consist of 2 qualified biologists conducting nocturnal spotlight surveys of parcels of prairie dog colony no larger than 320 acres in size for three consecutive nights to search for green eye shine and/or sightings of ferrets. Winter surveys consist of searching for ferret tracks, scats and trenches in the snow 24 hours after a fresh snow. These searches are usually conducted from snow machines or ATVs, but in some cases can be performed from a 4-wheel drive vehicle. The amount of area covered varies with snow conditions, terrain, and the amount of sign that needs to be investigated, but generally is approximately 1-square mile per day per individual. Three surveys, conducted 10 or more days apart, must be completed during the prescribed time period.

e. Black-Tailed Prairie Dog (Powder River Basin)

All black-tailed prairie dog towns within the project area must be located and their boundaries mapped. If the area to be surveyed is large, prairie dog towns are usually located from the air initially, and the boundaries are subsequently mapped on the ground by a biologist on an ATV, using a GPS unit to mark the edges of the town. Burrow densities are counted by riding an ATV along belt transects and counting the number of burrows. Numbers of burrow per unit of area are then calculated.

f. Preble's Meadow Jumping Mouse (Powder River Basin)

Live trapping to determine the occurrence or absence of this species is required within specific areas and potential habitats designated by the FWS. The person in charge of the trapping must meet stringent qualifications set forth by the FWS and must be present in the field during the trapping. Trapping must be performed within each potential habitat between June 1 and September 15 along trap lines for at least three consecutive nights with enough traps to produce 750 trap nights. Very exacting records must be kept on USFWS designed forms, and photographs of mice caught and the habitat they were captured in must be taken. Body measurements and weights of captured mice must be documented and a DNA plug sample taken from one ear and preserved for later analysis. A detailed report of trapping efforts and results must be submitted to the USFWS.

g. Bald Eagle (Powder River, Green River, Uinta-Piceance, and San Juan Basins)

A data base for this species sufficient for EIS and BA analyses usually exists, and specific surveys are not generally required. In some cases, surveys for winter occurrence and overnight roosting concentration areas are required. Such surveys consist of dawn flights to determine overnight roosting area. Such areas are generally in groves of tall trees with large open branches (mature cottonwoods and pine trees). When roosting areas are found, several dawn ground surveys may be required to determine the number of eagles using the roosts.

h. Mexican Spotted Owl (San Juan and Uinta-Piceance Basins)

Potential habitats for this species are surveyed at night during the breeding season along transects or routes. Observers stop at prescribed intervals and either play recorded vocalizations (hoots) of the spotted owl, or imitate the hooting with their own vocal cords. Observers then listen for and document responses of owls if they occur.

i. Whooping Crane (Green River, Uinta-Piceance, and San Juan Basins)

A data base for this species sufficient for EIS and BA analyses usually exists, and specific surveys are not generally required.

j. Interior Least Tern (Powder River Basin)

A data base for this species sufficient for EIS and BA analyses usually exists, and specific surveys are not generally required. Surveys, when required, consist of traversing wetland habitats during the breeding season and searching for the occurrence of birds and nests.

k. Southwest Willow Flycatcher (Green River, Uinta-Piceance, and San Juan Basins)

If potential habitats for this species exist on a project area it is usually necessary to map such habitats and to conduct breeding-season surveys on the ground. Singing male birds are surveyed from dawn until 0900 - 1000 hours along transects by playing recordings of the flycatcher's territorial song and documenting responses. The taped songs are played at 20 to 30 m intervals along the transect for 15 to 30 seconds. If a singing male is not heard within 1 to 2 minutes, the surveyor moves on to the next station. These surveys are repeated three times: 15 - 31 May; 1 - 21 June; and 22 June - 10 July.

l. Fish (Powder River, Green River, Uinta-Piceance, and San Juan Basins)

Data bases for these species that are sufficient for EIS and BA analyses usually exists, and specific surveys are not generally required.

m. T & E Plants (Powder River, Green River, Uinta-Piceance, and San Juan Basins)

The first step in the determination of whether or not a given threatened or endangered species of plant occurs in a particular project area is mapping of potentially suitable habitats for that species. If the governing agency already has this information on file, this step can be skipped. The second step is to perform ground surveys on potential habitats during the blooming season of the specified plant or plants.

n. Yellow-Billed Cuckoo (Powder River, Green River, Uinta-Piceance, and San Juan Basins)

When required, surveys for this species would involve walking transects through potential cuckoo habitats during the breeding season and stopping frequently to listen for calling males.

o. Mountain Plover (Powder River, Green River, Uinta-Piceance, and San Juan Basins)

For seismic work, field surveys are conducted during the plover nesting season (May 1 through June 15) over the entire project area to locate and delineate potential mountain plover nesting habitats, based on U.S. Fish and Wildlife criteria described in their current issue of mountain plover survey guidelines. Potential habitats are then surveyed 1 to 3 days ahead of proposed activities (including cadastral surveys) to determine whether or not plovers are present. If a break in the work occurs that in the opinion of the authorized officer is excessive, the area will need to be resurveyed.

For individual wells and other stationary facilities, three surveys are conducted over the area within a 1/4-mile radius of each well or facility, at 14-day intervals, between May 1 and June 15. Plover surveys for pipeline and other linear projects are conducted between April 10 and July 10 along the area within 1/4-mile of the pipeline alignment. These surveys are performed 1 to 3 days ahead of construction. All surveys are conducted between sunrise and 1000 and from 1730 to sunset from a vehicle or ATV.

p. Boreal Toad (Green River, Uinta-Piceance, and San Juan Basins)

When required, surveys for this species would involve: (1) surveying pond edges and other wet habitats during the breeding season to look for individual toads, and (2) conducting nocturnal surveys in boreal toad habitats to listen for croaking males. Toads that are located should be captured in a dip net to facilitate positive identification.

q. Columbian Spotted Frog (Uinta-Piceance Basin)

When required, survey protocol would be identical to that described for the boreal toad.

r. Peregrine Falcon (Powder River, Green River, and Uinta-Piceance Basins)

A data base for this species sufficient for EIS and BA analyses usually exists, and specific surveys are not generally required. When surveys are required, they involve utilizing a helicopter to inspect potential aeries in cliff areas that are 200 feet in height or more. These surveys are conducted during the falcon nesting period in the spring or early summer months.

7. Sensitive Species (Powder River, Green River, Uinta-Piceance, and San Juan Basins)

Sometimes required or encouraged when a particularly high interest species occurs in the project area.

8. Costs for Field Checks for Big Game Species

The purpose for field checking big game species is to determine whether or not it may be possible for an operator to submit an exception request that would allow the governing agency to waive a winter range or parturition range time exclusion stipulation. Specifically, the field check would determine the numbers and distribution of one or more big game species on a crucial habitat during the crucial season. If, for example, big game species were widely dispersed and not concentrated on a winter range because of mild weather conditions, it would be feasible to submit an exception request to the managing agency that would allow the operator to proceed with drilling or other construction.

Big game field checks consist of a biologist over-flying the crucial range in question to determine the numbers and distribution of animals. In some cases, such visits can be accomplished via ground vehicles, but this is not always possible on winter ranges. Approximate costs for 1-well and 10-well field checks are presented below:

- 1-well field check - $2,000
- 10-well field check - $2,700

B. Estimated Costs Associated with Wildlife Surveys and Lease Stipulations

The NPC Access Issues Team updated field survey costs originally published in BLM's White River Resource Management Plan (1997). These field surveys are performed to confirm the presence of wildlife species when operators propose new surface disturbance activities associated with wells, pipelines, or project expansions. In addition, expenses for cultural resource surveys and mitigation, typical expenses for a 30 well CBM pod, and filing of Applications for Permit to Drill are shown.

1. Costs for Field Surveys

NSO-02 Nests – T&E and Candidate T&E Species

$700 – Cursory field review, brief report (one day)

$3,500 – 2 to 3-day intensive field inventory

$2,800 – Annual inventory with mitigation, where applicable

NSO-03 Raptor Nests – Other than Special Status Raptors

$700 – Cursory field review, brief report (one day)

$3,500 – 2 to 3-day intensive field inventory

$2,800 – Annual inventory with mitigation, where applicable

NSO-04 Sage Grouse Leks

$700 – Cursory field review, brief report (one day)

$3,500 – 2 to 3-day intensive field inventory

$2,800 – Annual inventory with mitigation, where applicable

NSO-05 Bald Eagle Roost/Concentration Area

$700 – Cursory field review, brief report (one day)

$3,500 – 2 to 3-day intensive field inventory

$2,800 – Annual inventory with mitigation, where applicable

NSO-06 and 07 Proposed Area of Critical Environmental Concern (ACEC) (plants)

$1,120 – Plant inventory and report preparation

NSO-08 Proposed ACECs (plants)

$910 – Field inventory

$2,800 – Monitoring and report preparation

CSU-01 Fragile Soils >35%

$1,500 to $4,000 – Preparation and distribution of reclamation plan (cost range exists due to variance in >35% slopes for a project)

CSU-02 Designated ACECs (See NSO-6)

CSU-03 Proposed ACECs (See NSO-6)

CSU-04 Ferret Reintroduction

$5,000 to $30,000 – Costs depend upon extent of mitigation, including fencing, avoiding prairie dog colonies, and participating in ferret surveys

$100,000 – Cost to directionally drill a well to reduce conflicts

Black-Footed Ferret Surveys in Potential Habitat (Prairie Dog Towns)

$10,000 per 320 acre survey if new disturbance is involved. Survey requires two biologists and three consecutive nights. Three surveys, conducted 10 or more days apart, are required.

TL-01 Raptor Nesting Sites (Listed and Candidate T/E except Bald Eagle and Ferruginous Hawks)

$700 – Cursory field review, brief report (one day)

$3,500 – 2 to 3-day intensive field inventory

$2,800 – Annual inventory with mitigation, where applicable

TL-04 Raptor Nests (other than T/E and Candidate T/E species)

$700 – Cursory field review, brief report (one day)

$3,500 – 2 to 3-day intensive field inventory

$2,800 – Annual inventory with mitigation, where applicable

TL-05 Bald Eagle Roost Concentration

$700 – Cursory field review, brief report (one day)

$3,500 – 2 to 3-day intensive field inventory

$2,800 – Annual inventory with mitigation, where applicable

TL-06 Sage Grouse Nest Habitat

$700 – Cursory field review, brief report (one day)

$3,500 – 2 to 3-day intensive field inventory

$2,800 – Annual inventory with mitigation, where applicable

TL-08 Big Game Timing Exception Report

$2,000 – Site inspection inventory

$3,500 – 2 to 3-day intensive site inspection inventory

TL-09 Deer/Elk Summer Range

$1,200 – Wildlife site inspection report

Mountain Plover Surveys

$5,000 – Survey 20 linear miles for right-of-way or geophysical projects.

$5,000 – Survey 20 square miles for wildcat well or development well locations.

2. Costs for Protection of Archeological and Paleontological Sites during Disturbance

$1,500 to $4,000 – Survey of a drill pad and right-of-way (10 acres) and a Class III survey and report where no resources exist

$4,000 to $6,000 – Class III survey with identified archeological or historical sites, which requires preparation of an historical report documenting the presence and significance of >50 year old properties, significant prehistoric sites, or which may affect national historic sites, trails, and properties

$2,500 – Monitoring during construction activities

$10,000 (minimum) – Data Recovery and Treatment Plan that may cover several sites (30 square meters)

$50,000 to $250,000 per site – depending on complexity, to implement the Data Recovery and Treatment Plan (site excavation and recordation)

3. Costs to File an Application for Permit to Drill

These costs are incurred when operators file applications for permits to drill. Operators are required to survey locations, conduct archeological and wildlife surveys.

Road, drill pad, and pipeline (<5 acres disturbance) costs are incurred on a one-time basis. If drill pad and right-of-way locations are relocated to protect archeological or wildlife resources, these costs are incurred again.

$3,000 to $7,000 – Road centerline and drill pad survey

A greater than 5-acre disturbance triggers additional requirements but do not include emissions permits such as air, water discharge, NPDES, SPCC, and the like.

$3,000 to $7,000 – Land Survey as above

$3,500 – Wetlands delineation (2 to 3 day intensive field inventory)

$1,000 – Stormwater permit application and monitoring

4. Road, Drill Pad, and Construction Costs

Costs shown below are for stand-alone wells in the Greater Green River Basin.

$10,000 to $15,000 – Cost for typical BLM road construction with less than 5% grade per mile, including gates, fencing, and cattle guards

$15,000 to $30,000 – Cost per mile for typical national forest road built to Forest Service standards (wing ditches, crown, culverts, and 4 inches of gravel)

$30,000 to 75,000 – Typical drill pad, flowline, and access road (< 5 acres total disturbance) in topography with less than a 5% grade

Gas gathering pipeline – $10 to $20 per linear foot to ditch, lay, weld, wrap, bury, and backfill. Note: A centerline archeological survey is required, and costs will be the same as a Class III with a historical report plus monitoring during construction ($4k to $6k plus $2.5k for monitoring)

5. Drilling Costs

Drilling costs presented in this section are averaged from wells drilled in the central portion of the Green River Basin (9,500') and Wamsutter (11,000') areas.

$700k to $1.1M – Cost to drill and complete vertical wells

(Add 30% to drill and complete directional wells, 2,500-foot maximum throw)

Costs shown below are for CBM wells in the Powder River Basin, based on a 30-well Plan of Development (POD) that is required by BLM.

Drilling	$1,860,000
Facilities	$1,320,000
Survey	$120,000
Archaeology	$40,000
Wildlife	$6,000
Water Management Plan (treatment and surface disposal)	$20,000
Land – Initial Agreement	$45,000
Pit Construction	$280,000
Total cost for 30 well POD	$3,691,000

In addition, $45,000 per year for annual landowner settlement and $20,000 per year for water monitoring is required.

6. Reclamation Costs

Reclamation of dry holes

$10,000 to $15,000 – Cost per mile to reclaim typical BLM road in areas with less than 5% grade

$15,000 to $30,000 – Cost per mile to reclaim typical national forest road

$30,000 to $75,000 – Cost to reclaim typical drill pad, flowline and access road (< 5 acres total disturbance) in topography with less than a 5% grade

7. Examples of Costs Associated with Wildlife Surveys and Lease Stipulations

Example: Routine well in Green River Basin under Standard Lease Term

Expenses for Wamsutter 9-34, Section 34, T21N, R94W, located in Greater Green River Basin for a routine well that is "conflict free." The APD was submitted October 15, 2002, and approved January 17, 2003. However, road and pad construction cannot be initiated due to sage grouse restrictions that prohibit activity from March 1 to June 30. Wells in this area typically produce 1 MCF/D. At $4 MCF, the six-month delay for sage grouse restrictions equate to $730,000 in deferred gross revenues or $91,250 in royalties to state and federal governments.

Environmental Costs	
Land Survey	$3,500
Arch Survey	$1,100
Sage Grouse (study done in 2001)	$2,100
Construction Costs	
Access Road and Drill Pad	$25,000

Example: Typical well in big game habitat (obtain waiver from seasonal use stipulation)

Example: Well in NSO (obtain waiver from NSO stipulation)

VIII. Quantitative Analysis Matrix Inputs

Please refer to the Data CD for these tables.

IX. Quantitative Analysis Matrix Output Sheets

The tables on the following pages summarize the results of the access analysis of the Powder River, Green River, San Juan, and Uinta-Piceance Basins. For each basin, results are given for exploration and development wells, and for federal, state, and fee lands. These data are provided in Excel format on the Data CD.

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0				$35,917	$60,034	$46,093	$139,353	$108,036
1								
2								
3								
4								
5					$68,582		$143,175	$95,707
6				$38,000	$60,407	$45,920	$146,697	$118,002
7								
8			$29,100	$35,787	$59,921	$45,576	$136,007	$100,723
9					$65,780		$144,792	$125,039
10					$67,551	$43,640	$140,269	$99,901
11				$35,380	$59,467	$45,021	$137,778	$102,163
12					$62,583	$44,741	$151,324	$110,377
All			$29,100	$35,903	$60,945	$45,531	$140,474	$106,623

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0				1.2%	6.0%	2.7%	17.3%	27.2%
1								
2								
3								
4								
5					1.4%		0.8%	2.2%
6				0.2%	4.3%	1.0%	11.7%	17.2%
7								
8			0.3%	1.5%	4.7%	3.9%	14.9%	25.3%
9					0.2%		0.6%	0.8%
10					0.9%	0.2%	1.0%	2.1%
11				0.5%	5.5%	2.1%	10.9%	19.0%
12					1.9%	0.8%	3.5%	6.2%
All			0.3%	3.4%	24.9%	10.7%	60.7%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

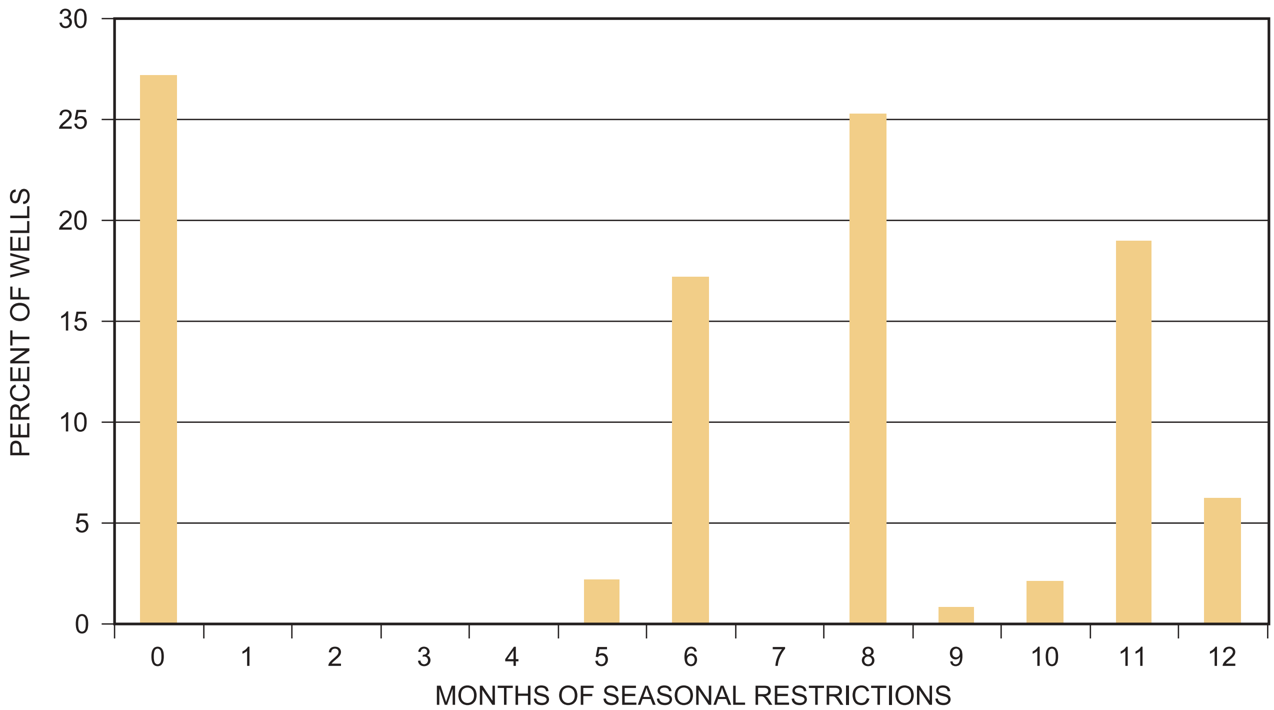
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0								
3								
6				0.9%	7.2%	3.2%	21.7%	33.0%
9			0.3%	2.5%	17.7%	7.5%	39.0%	67.0%
12								
18								
24								
36+								
All			0.3%	3.4%	24.9%	10.7%	60.7%	100.0%

Unavailable Resources on Federal Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
10.5%	25.1%*	35.6%

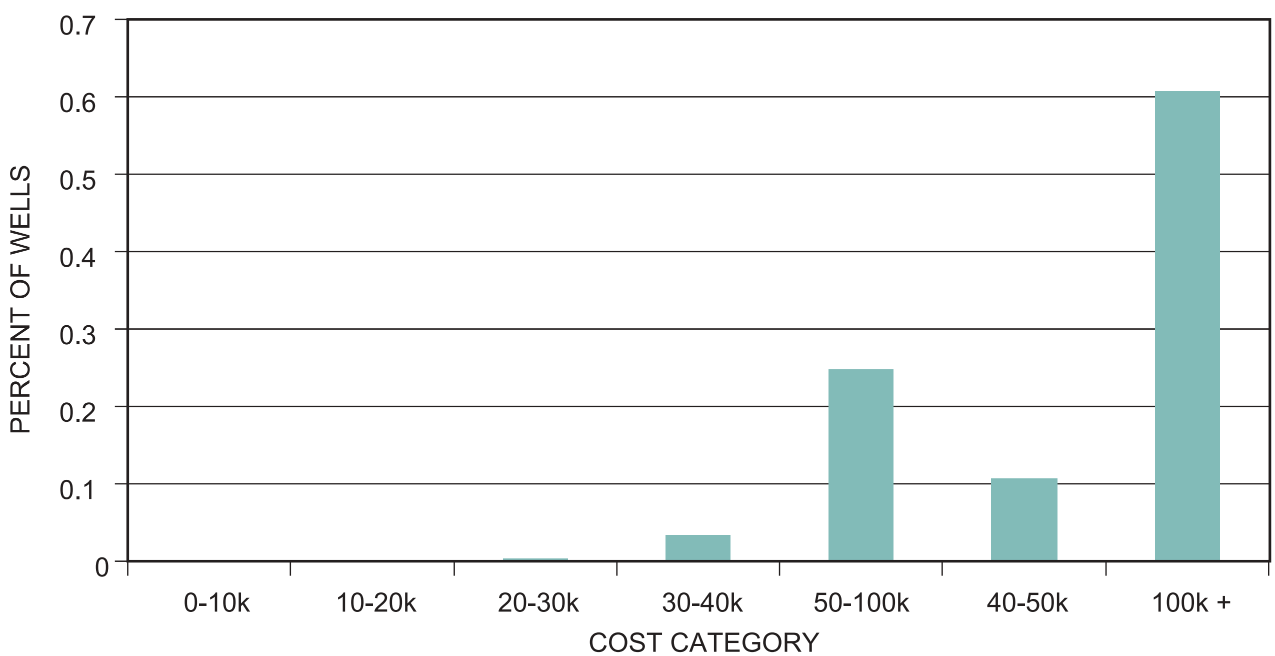
H.C. % =	40.0%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Powder River Basin (All) – Exploratory Wells: Federal



Percent of Wells By Months of Seasonal Restrictions: Powder River Basin (All)



Percent of Wells By Cost Category: Powder River Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0				$35,917	$60,034	$46,093	$139,353	$108,036
1								
2								
3								
4								
5					$68,582		$143,175	$95,707
6				$38,000	$60,407	$45,920	$146,697	$118,002
7								
8			$29,100	$35,787	$59,921	$45,576	$136,007	$100,723
9					$65,780		$144,792	$125,039
10					$67,551	$43,640	$140,269	$99,901
11				$35,380	$59,467	$45,021	$137,778	$102,163
12					$62,583	$44,741	$151,324	$110,377
All			$29,100	$35,903	$60,945	$45,531	$140,474	$106,623

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0				1.2%	6.0%	2.7%	17.3%	27.2%
1								
2								
3								
4								
5					1.4%		0.8%	2.2%
6				0.2%	4.3%	1.0%	11.7%	17.2%
7								
8			0.3%	1.5%	4.7%	3.9%	14.9%	25.3%
9					0.2%		0.6%	0.8%
10					0.9%	0.2%	1.0%	2.1%
11				0.5%	5.5%	2.1%	10.9%	19.0%
12					1.9%	0.8%	3.5%	6.2%
All			0.3%	3.4%	24.9%	10.7%	60.7%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

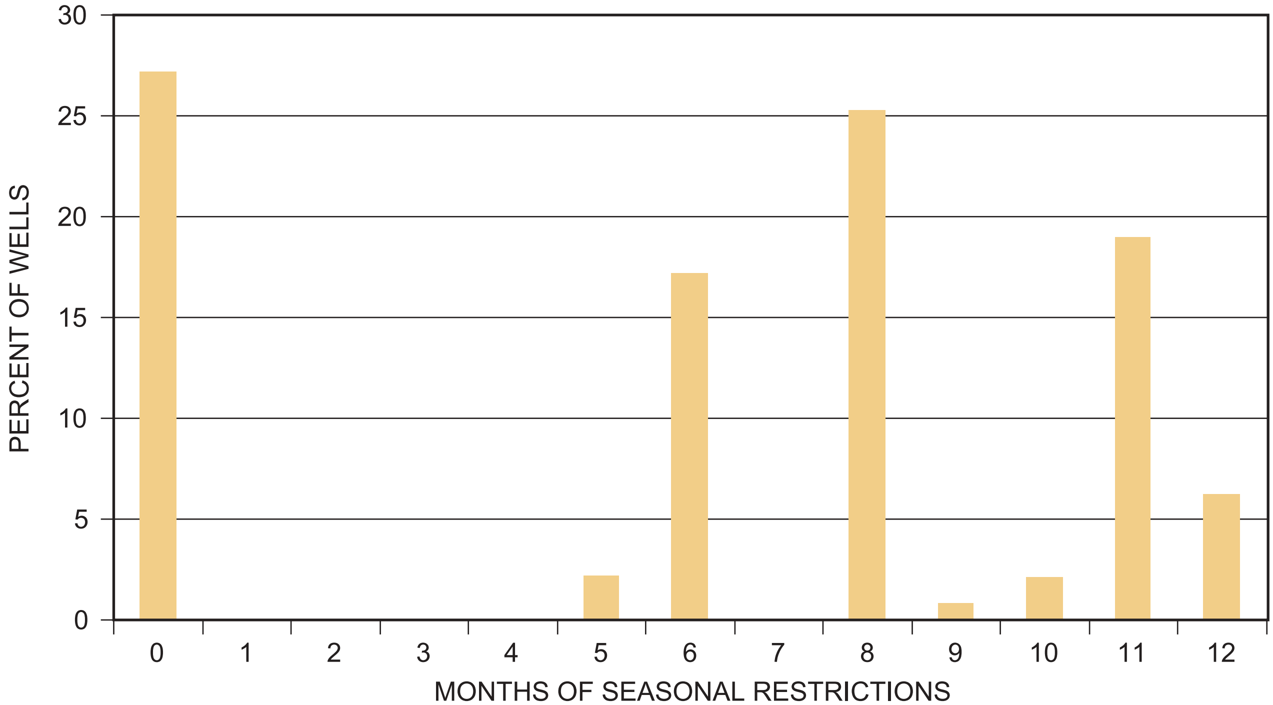
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0								
3								
6				0.9%	7.2%	3.2%	21.7%	33.0%
9			0.3%	2.5%	17.7%	7.5%	39.0%	67.0%
12								
18								
24								
36+								
All			0.3%	3.4%	24.9%	10.7%	60.7%	100.0%

Unavailable Resources on State Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
0.0%	28.1%*	28.1%

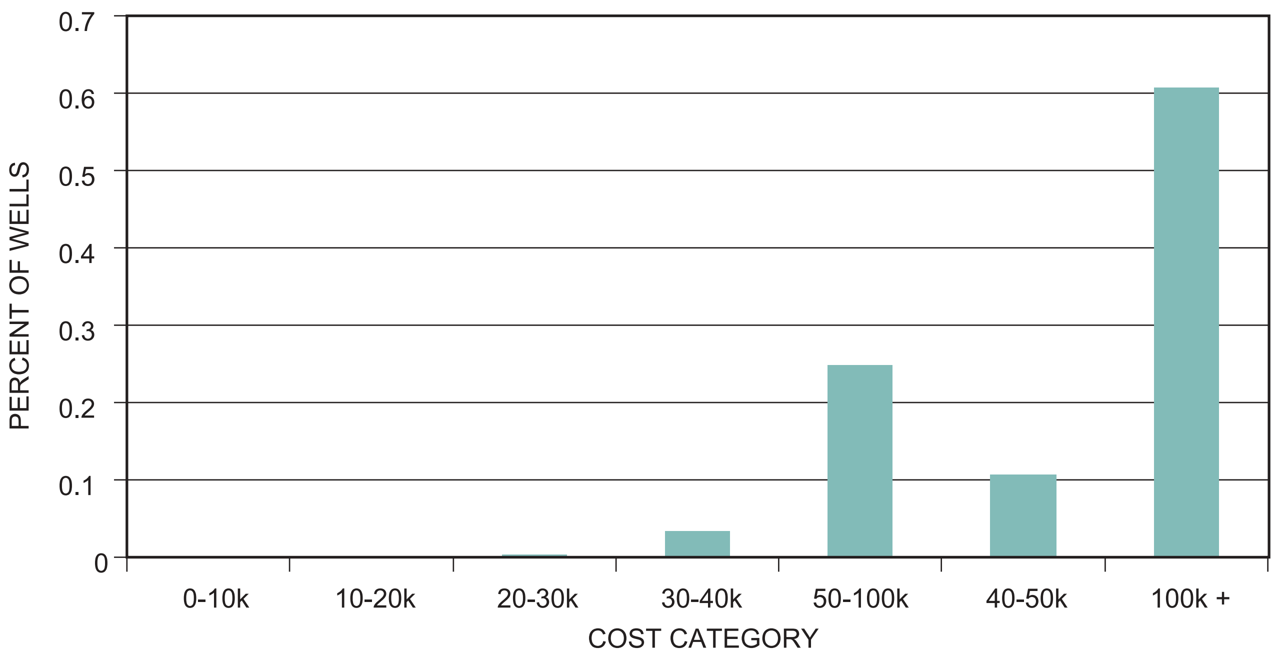
H.C. % = 44.7%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Powder River Basin (All) – Exploratory Wells: State



Percent of Wells By Months of Seasonal Restrictions: Powder River Basin (All)



Percent of Wells By Cost Category: Powder River Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0		$14,536	$26,572					$18,291
1								
2								
3								
4								
5			$20,600	$32,600				$24,418
6		$17,100	$28,153	$35,100				$21,229
7								
8		$10,207	$22,100					$14,418
9								
10								
11		$13,271	$25,502	$32,100				$17,773
12		$13,544	$24,758	$30,600				$17,654
All		$13,474	$24,998	$32,975				$17,727

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0		19.4%	8.8%					28.2%
1								
2								
3								
4								
5			1.5%	0.7%				2.2%
6		10.9%	5.7%	0.4%				17.0%
7								
8		17.7%	9.7%					27.4%
9								
10								0.0%
11		12.6%	6.6%	0.4%				19.6%
12		3.6%	1.9%	0.1%				5.6%
All		64.2%	34.2%	1.6%				100.0%

Percent of Wells By Costs Category and Months of Processing Delay

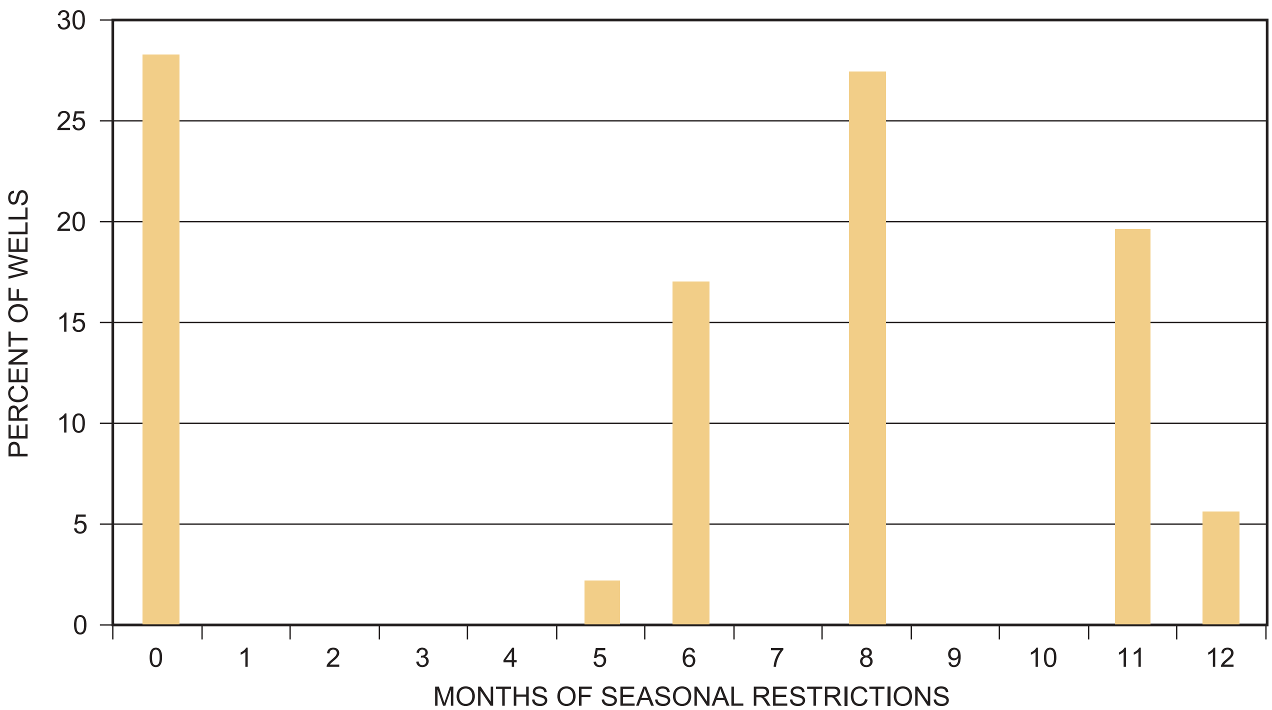
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0								
3		31.9%	17.0%	1.1%				50.0%
6								
9		32.3%	17.2%	0.5%				50.0%
12								
18								
24								
36+								
All		64.2%	34.2%	1.6%				100.0%

Unavailable Resources on Fee Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
0.0%	25.2%*	25.2%

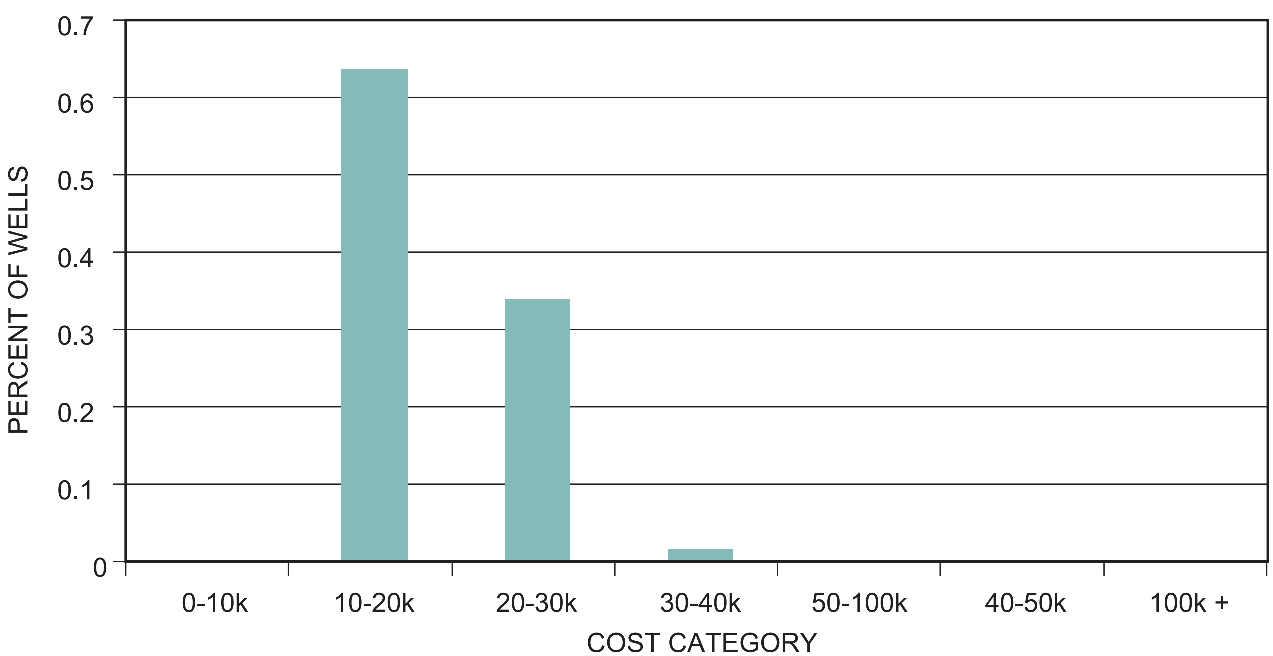
H.C. % = 0.0%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Powder River Basin (All) – Exploratory Wells: Fee



Percent of Wells By Months of Seasonal Restrictions: Powder River Basin (All)



Percent of Wells By Cost Category: Powder River Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0				$35,597	$62,006	$46,387	$116,800	$57,228
1								
2								
3								
4								
5					$70,219	$43,700		$69,014
6				$39,270	$65,904	$46,494	$126,416	$65,084
7								
8			$27,757	$36,338	$62,245	$45,734	$106,858	$53,626
9					$71,451			$71,451
10					$69,023	$45,820		$65,709
11			$27,800	$36,100	$63,657	$46,593	$131,375	$59,069
12				$32,500	$65,991	$46,089	$113,813	$63,721
All			$27,763	$36,271	$64,045	$46,141	$117,056	$58,971

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0				1.7%	17.8%	7.2%	0.5%	27.2%
1								
2								
3								
4								
5					2.1%	0.1%		2.2%
6				0.5%	14.6%	1.6%	0.5%	17.2%
7								
8			0.7%	2.4%	12.0%	9.6%	0.6%	25.3%
9					0.8%			0.8%
10					1.8%	0.3%		2.1%
11			0.1%	0.8%	13.5%	4.4%	0.2%	19.0%
12				0.1%	4.2%	1.5%	0.4%	6.2%
All			0.8%	5.5%	66.8%	24.7%	2.2%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

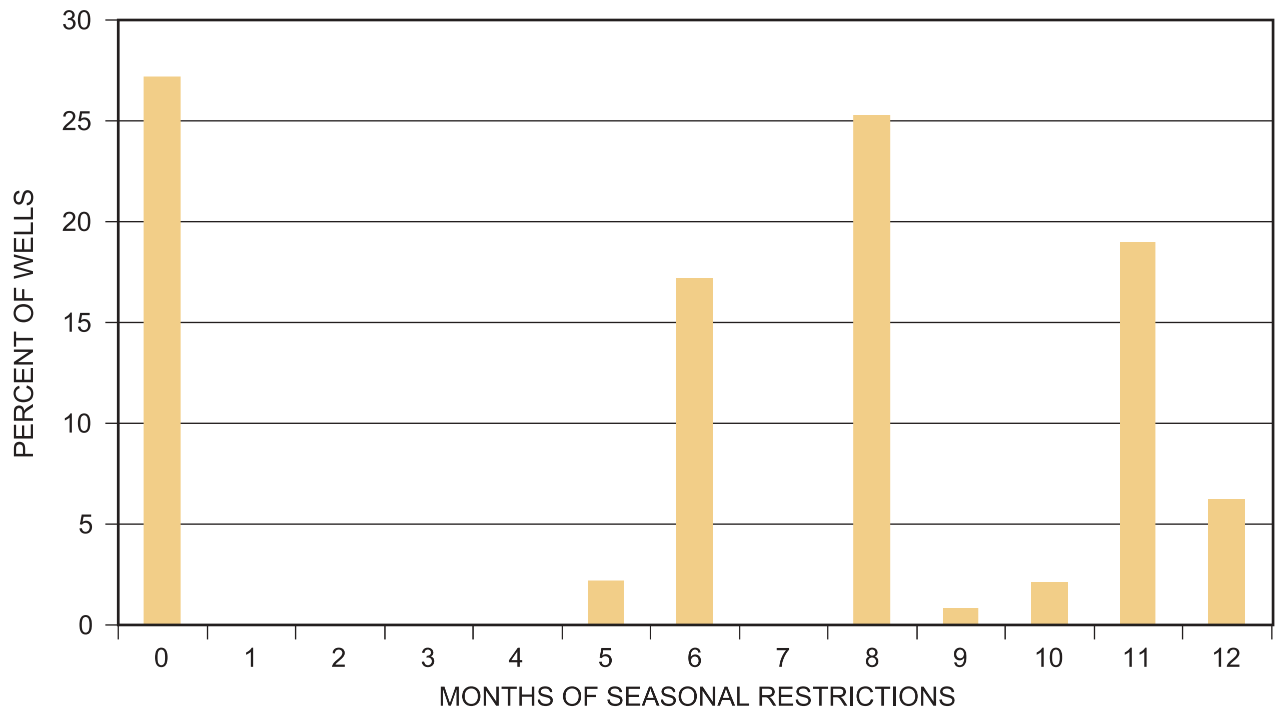
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0								
3								
6			0.7%	3.8%	39.2%	15.1%	1.2%	60.0%
9								
12								
18								
24			0.1%	1.7%	27.6%	9.6%	1.0%	40.0%
36+								
All			0.8%	5.5%	66.8%	24.7%	2.2%	100.0%

Unavailable Resources on Federal Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
10.5%	25.1%*	35.6%

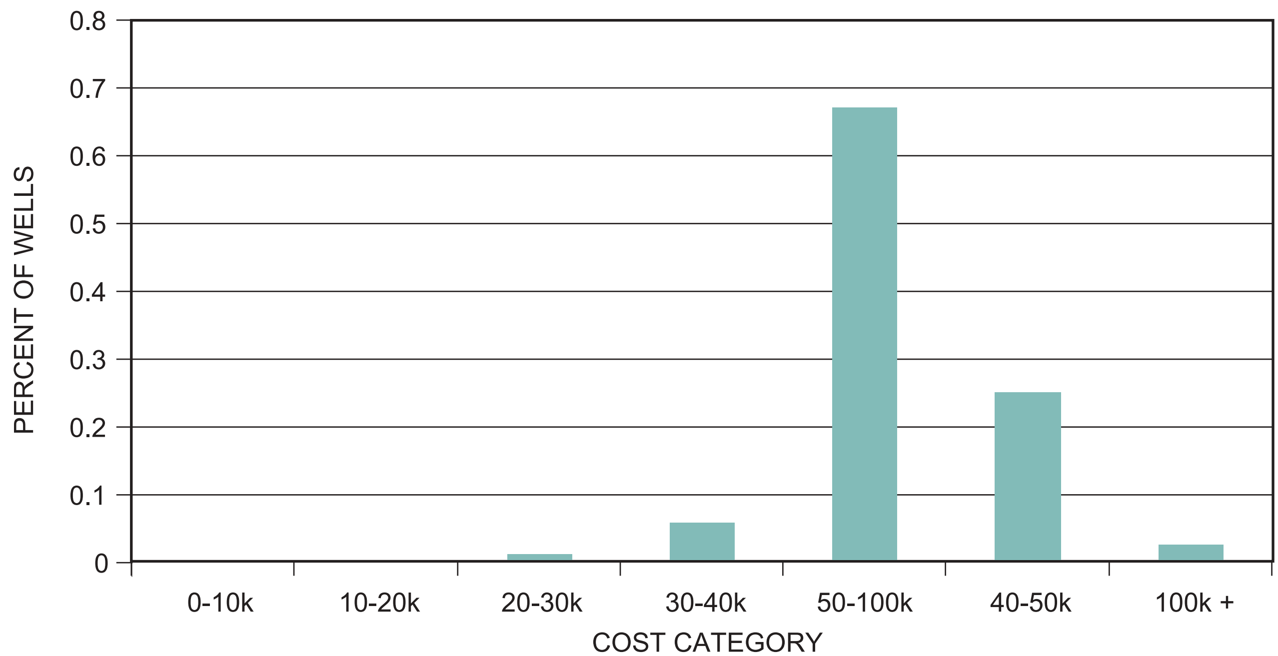
H.C. % =	1.4%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Powder River Basin (All) – Development Wells: Federal



Percent of Wells By Months of Seasonal Restrictions: Powder River Basin (All)



Percent of Wells By Cost Category: Powder River Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0				$35,597	$62,006	$46,387	$116,800	$57,228
1								
2								
3								
4								
5					$70,219	$43,700		$69,014
6				$39,270	$65,904	$46,494	$126,416	$65,084
7								
8			$27,757	$36,338	$62,245	$45,734	$106,858	$53,626
9					$71,451			$71,451
10					$69,023	$45,820		$65,709
11			$27,800	$36,100	$63,657	$46,593	$131,375	$59,069
12				$32,500	$65,991	$46,089	$113,813	$63,721
All			$27,763	$36,271	$64,045	$46,141	$117,056	$58,971

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0				1.7%	17.8%	7.2%	0.5%	27.2%
1								
2								
3								
4								
5					2.1%	0.1%		2.2%
6				0.5%	14.6%	1.6%	0.5%	17.2%
7								
8			0.7%	2.4%	12.0%	9.6%	0.6%	25.3%
9					0.8%			0.8%
10					1.8%	0.3%		2.1%
11			0.1%	0.8%	13.5%	4.4%	0.2%	19.0%
12				0.1%	4.2%	1.5%	0.4%	6.2%
All			0.8%	5.5%	66.8%	24.7%	2.2%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

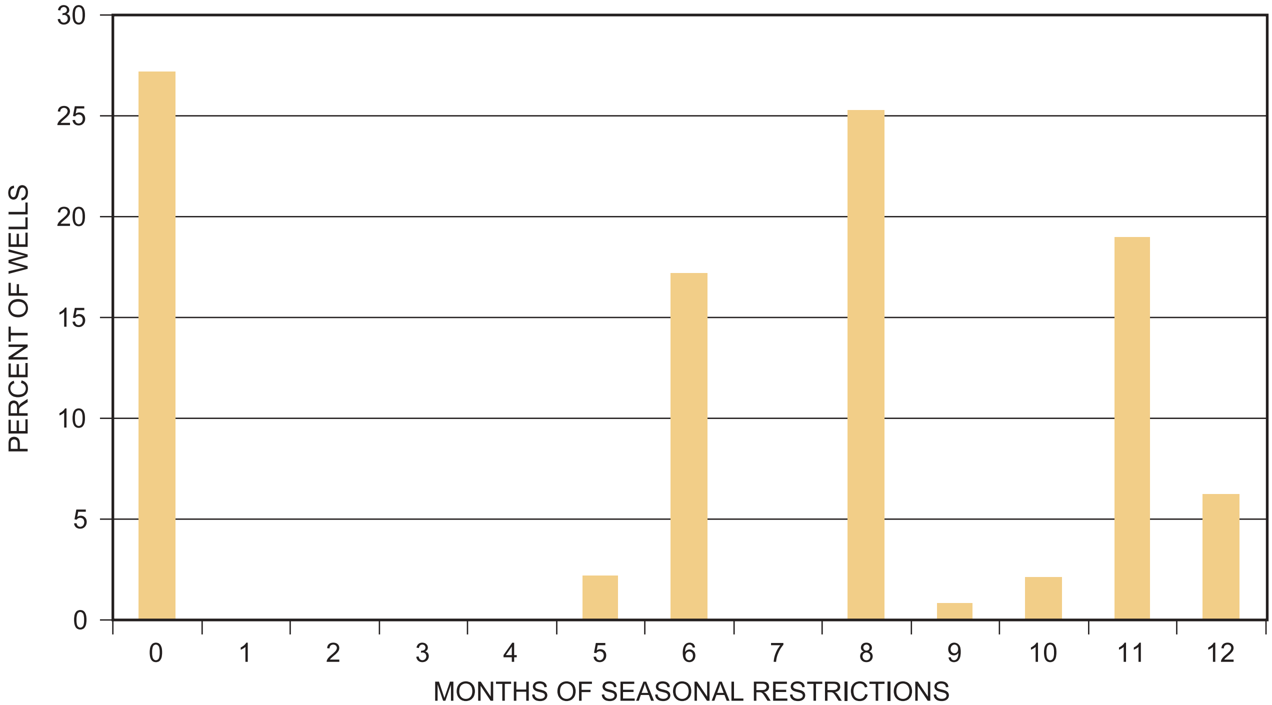
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0								
3								
6			0.7%	3.8%	39.2%	15.1%	1.2%	60.0%
9								
12								
18								
24			0.1%	1.7%	27.6%	9.6%	1.0%	40.0%
36+								
All			0.8%	5.5%	66.8%	24.7%	2.2%	100.0%

Unavailable Resources on State Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
0.0%	28.1%*	28.1%

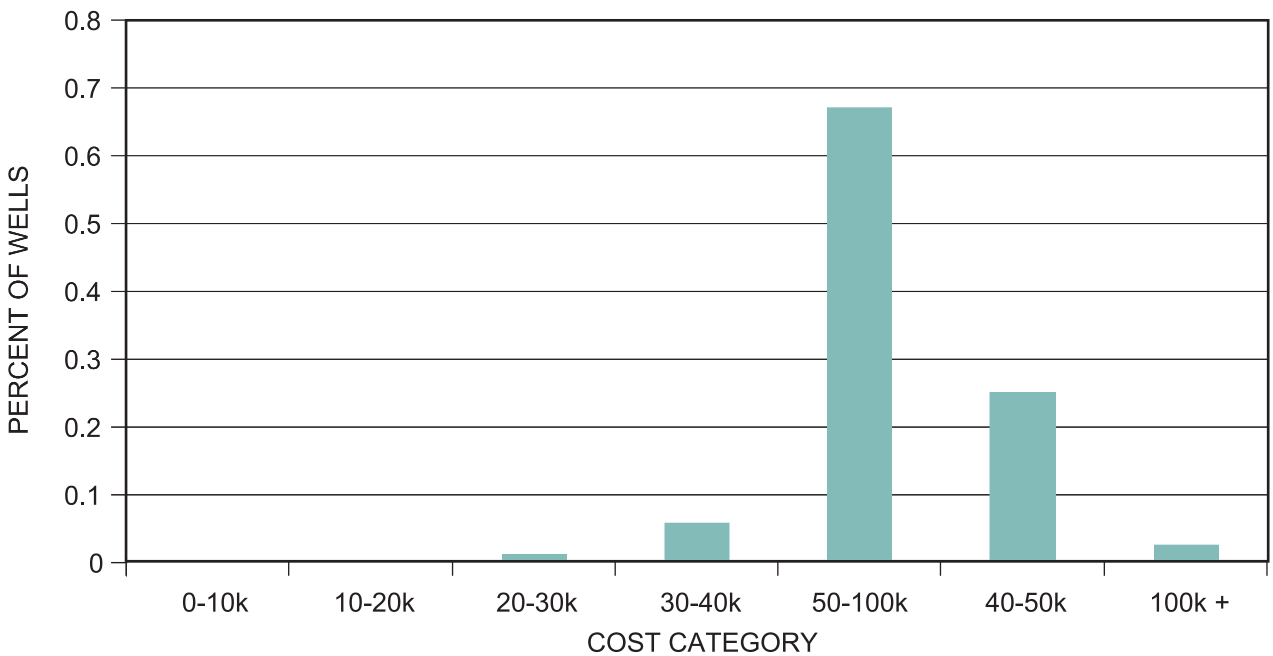
H.C. % = 1.6%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Powder River Basin (All) – Development Wells: State



Percent of Wells By Months of Seasonal Restrictions: Powder River Basin (All)



Percent of Wells By Cost Category: Powder River Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0		$14,636	$26,668	$38,700				$18,817
1								
2								
3								
4								
5			$20,700	$32,700		$44,700		$25,064
6			$20,458	$32,511		$44,000		$24,482
7								
8		$10,307	$22,200	$34,200	$58,200	$46,200		$15,087
9								
10								
11		$15,583	$27,286	$37,500		$40,200		$20,602
12		$12,271	$22,808	$36,100		$44,750		$20,025
All		$13,268	$23,377	$34,126	$58,200	$43,917		$19,313

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0		19.4%	7.8%	1.0%				28.2%
1								
2								
3								
4								
5			1.5%	0.6%		0.1%		2.2%
6			11.8%	4.7%		0.5%		17.0%
7								
8		17.7%	8.8%	0.6%	0.1%	0.2%		27.4%
9								
10								0.0%
11		12.2%	6.3%	0.9%		0.2%		19.6%
12		2.4%	2.6%	0.4%		0.2%		5.6%
All		51.7%	38.8%	8.2%	0.1%	1.2%		100.0%

Percent of Wells By Costs Category and Months of Processing Delay

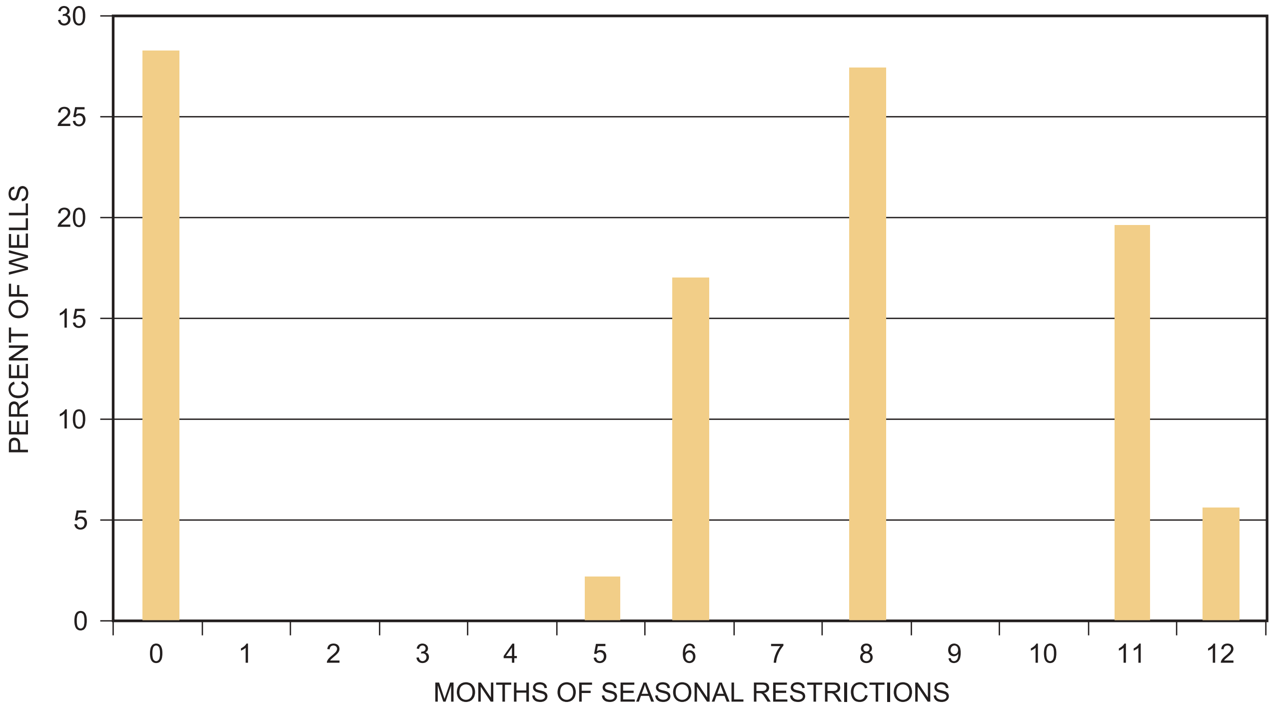
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0		12.1%						12.1%
3		39.6%	38.8%	8.2%	0.1%	1.2%		87.9%
6								
9								
12								
18								
24								
36+								
All		51.7%	38.8%	8.2%	0.1%	1.2%		100.0%

Unavailable Resources on Fee Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
0.0%	25.2%*	25.2%

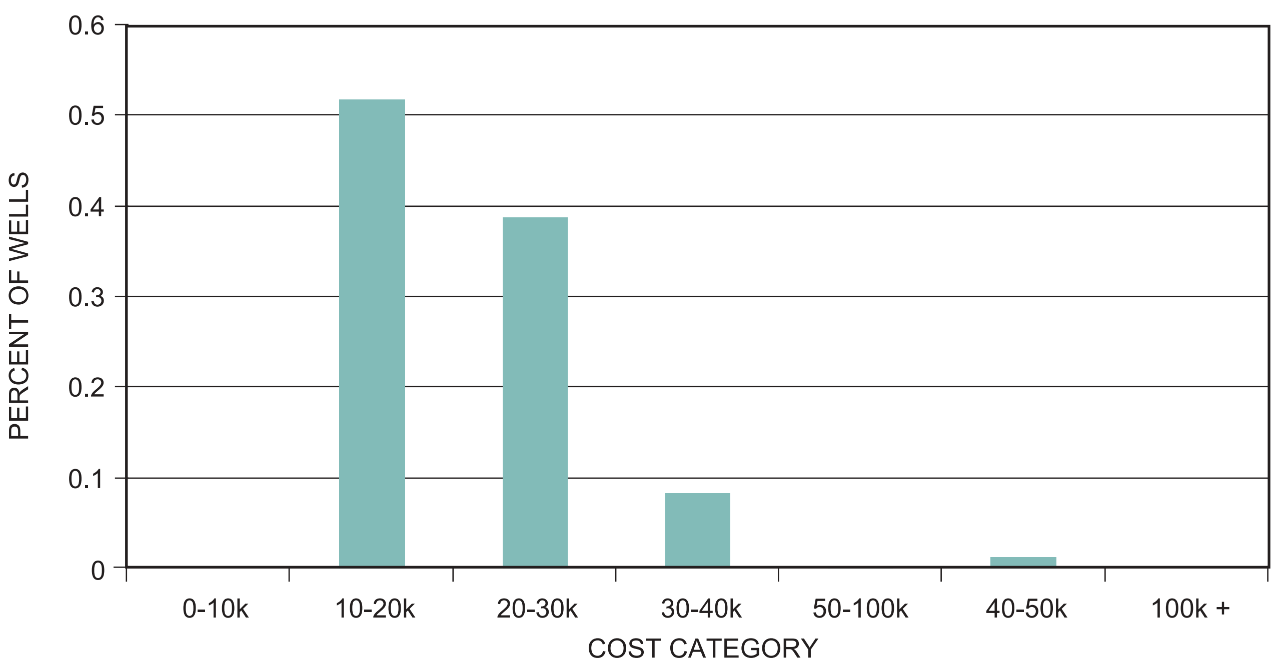
H.C. % =	0.0%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Powder River Basin (All) – Development Wells: Fee



Percent of Wells By Months of Seasonal Restrictions: Powder River Basin (All)



Percent of Wells By Cost Category: Powder River Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0		$17,300	$27,232	$34,021	$94,680	$41,900	$286,078	$233,746
1								
2								
3								
4								
5				$37,900	$52,700		$287,433	$226,900
6		$19,400	$26,650	$35,060	$98,100	$43,011	$296,867	$256,624
7								
8								
9			$26,680	$37,130		$44,568	$287,170	$259,292
10								
11								
12		$19,400	$27,672	$36,168	$84,171	$42,526	$276,695	$235,130
All		$17,900	$27,262	$35,067	$88,980	$42,971	$287,432	$244,091

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0		0.5%	2.2%	2.4%	1.0%	0.2%	23.3%	29.6%
1								
2								
3								
4								
5				0.1%	0.1%		0.6%	0.8%
6		0.1%	0.8%	2.5%	0.3%	1.6%	28.6%	33.9%
7								
8								
9			0.1%	0.5%		0.4%	7.9%	8.9%
10								0.0%
11								0.0%
12		0.1%	1.5%	1.1%	1.0%	1.1%	22.0%	26.8%
All		0.7%	4.6%	6.6%	2.4%	3.3%	82.4%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

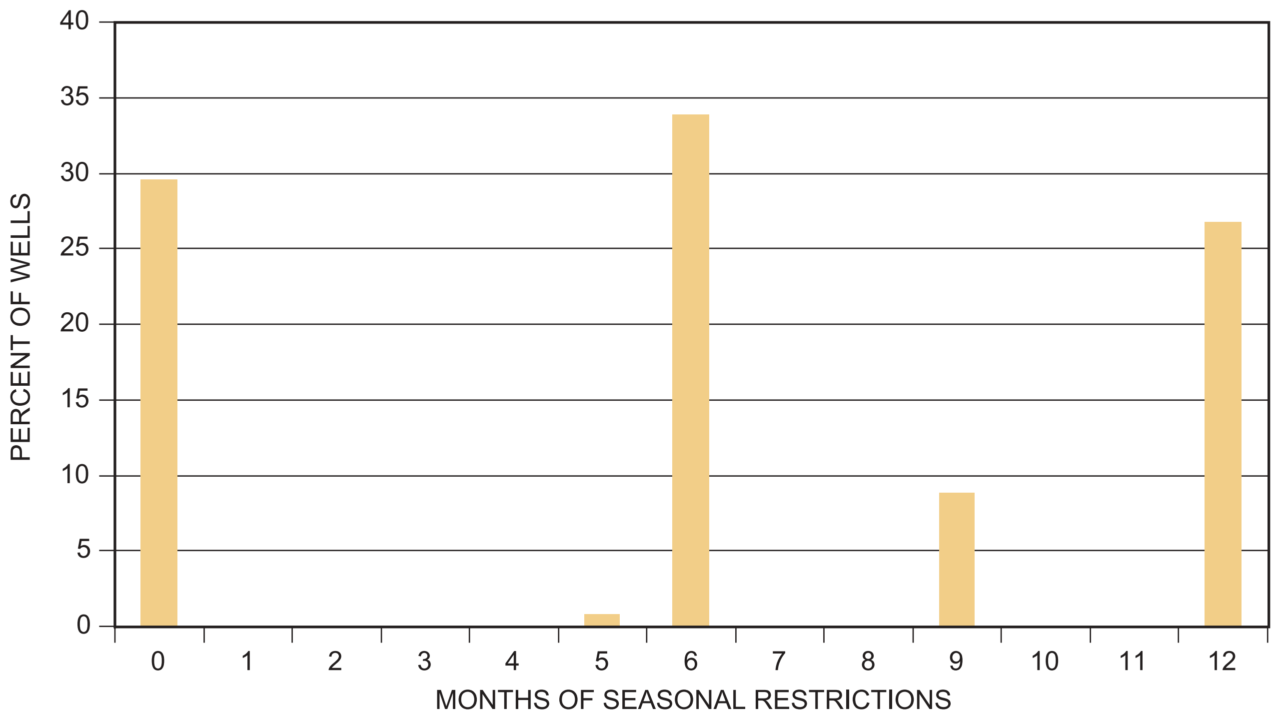
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0								
3								
6		0.5%	3.2%	2.8%	0.3%	0.9%	3.8%	11.5%
9		0.2%	1.4%	3.8%	0.6%	2.4%	9.8%	18.2%
12					1.5%		57.4%	58.9%
18								
24								
36+							11.4%	11.4%
All		0.7%	4.6%	6.6%	2.4%	3.3%	82.4%	100.0%

Unavailable Resources on Federal Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
12.0%	31.4%*	43.4%

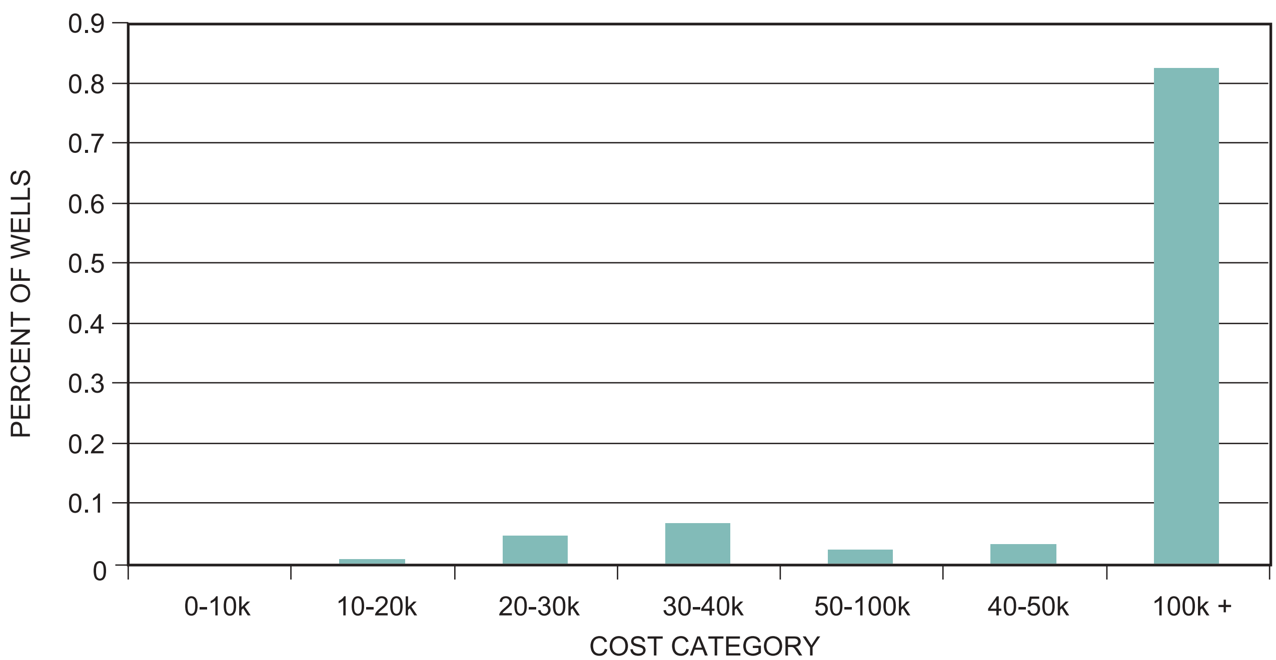
H.C. % = 46.2%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Green River Basin (All) – Exploratory Wells: Federal



Percent of Wells By Months of Seasonal Restrictions: Green River Basin (All)



Percent of Wells By Cost Category: Green River Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0		$17,300	$27,232	$34,021	$94,680	$41,900	$286,078	$233,746
1								
2								
3								
4								
5				$37,900	$52,700		$287,433	$226,900
6		$19,400	$26,650	$35,060	$98,100	$43,011	$296,867	$256,624
7								
8								
9			$26,680	$37,130		$44,568	$287,170	$259,292
10								
11								
12		$19,400	$27,672	$36,168	$84,171	$42,526	$276,695	$235,130
All		$17,900	$27,262	$35,067	$88,980	$42,971	$287,432	$244,091

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0		0.5%	2.2%	2.4%	1.0%	0.2%	23.3%	29.6%
1								
2								
3								
4								
5				0.1%	0.1%		0.6%	0.8%
6		0.1%	0.8%	2.5%	0.3%	1.6%	28.6%	33.9%
7								
8								
9			0.1%	0.5%		0.4%	7.9%	8.9%
10								0.0%
11								0.0%
12		0.1%	1.5%	1.1%	1.0%	1.1%	22.0%	26.8%
All		0.7%	4.6%	6.6%	2.4%	3.3%	82.4%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

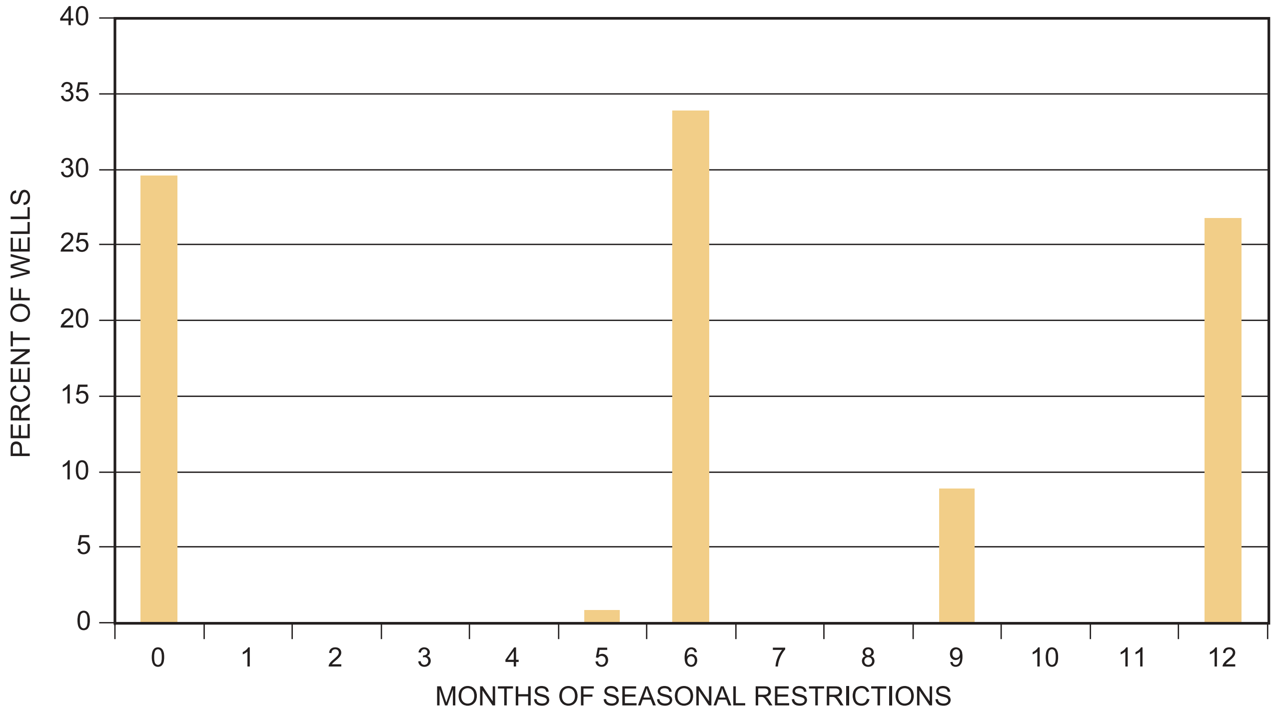
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0								
3								
6		0.5%	3.2%	2.8%	0.3%	0.9%	3.8%	11.5%
9		0.2%	1.4%	3.8%	0.6%	2.4%	9.8%	18.2%
12					1.5%		57.4%	58.9%
18								
24								
36+							11.4%	11.4%
All		0.7%	4.6%	6.6%	2.4%	3.3%	82.4%	100.0%

Unavailable Resources on State Lands		
EPCA (Fed only)	NPC Addition	Total
0.0%	35.7%*	35.7%

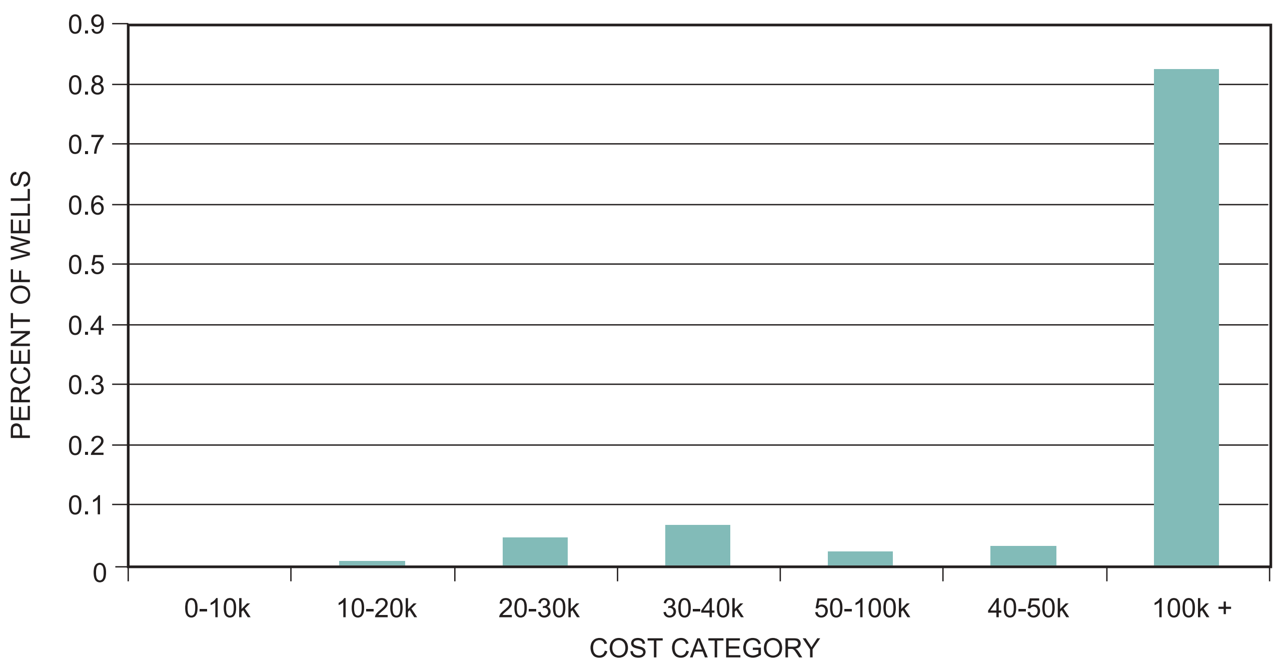
H.C. % =	52.5%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Green River Basin (All) – Exploratory Wells: State



Percent of Wells By Months of Seasonal Restrictions: Green River Basin (All)



Percent of Wells By Cost Category: Green River Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	$2,039						$115,779	$47,635
1								
2								
3								
4								
5	$7,767						$114,183	$60,975
6	$5,100	$11,100					$111,208	$49,446
7								
8								
9								
10								
11								
12	$2,990	$11,100					$123,095	$51,003
All	$3,144	$11,100					$116,434	$49,180

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	27.2%						18.2%	45.4%
1								
2								
3								
4								
5	0.6%						0.6%	1.2%
6	15.2%	0.3%					11.1%	26.6%
7								
8								
9								
10								0.0%
11								0.0%
12	15.9%	0.2%					10.7%	26.8%
All	58.9%	0.5%					40.6%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	35.2%							35.2%
3	23.7%	0.5%					40.2%	64.4%
6								
9								
12								
18								
24								
36+							0.4%	0.4%
All	58.9%	0.5%					40.6%	100.0%

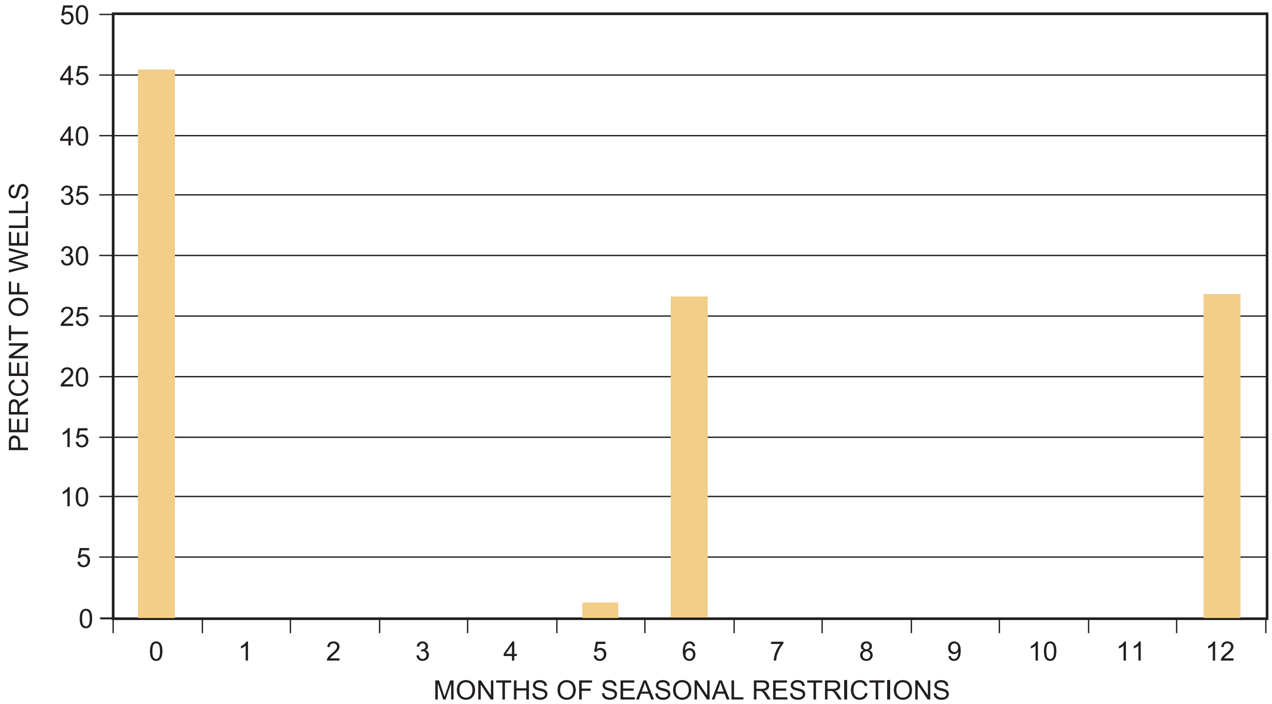
Unavailable Resources on Fee Lands

EPCA (Fed only)	NPC Addition	Total
0.0%	26.8%*	26.8%

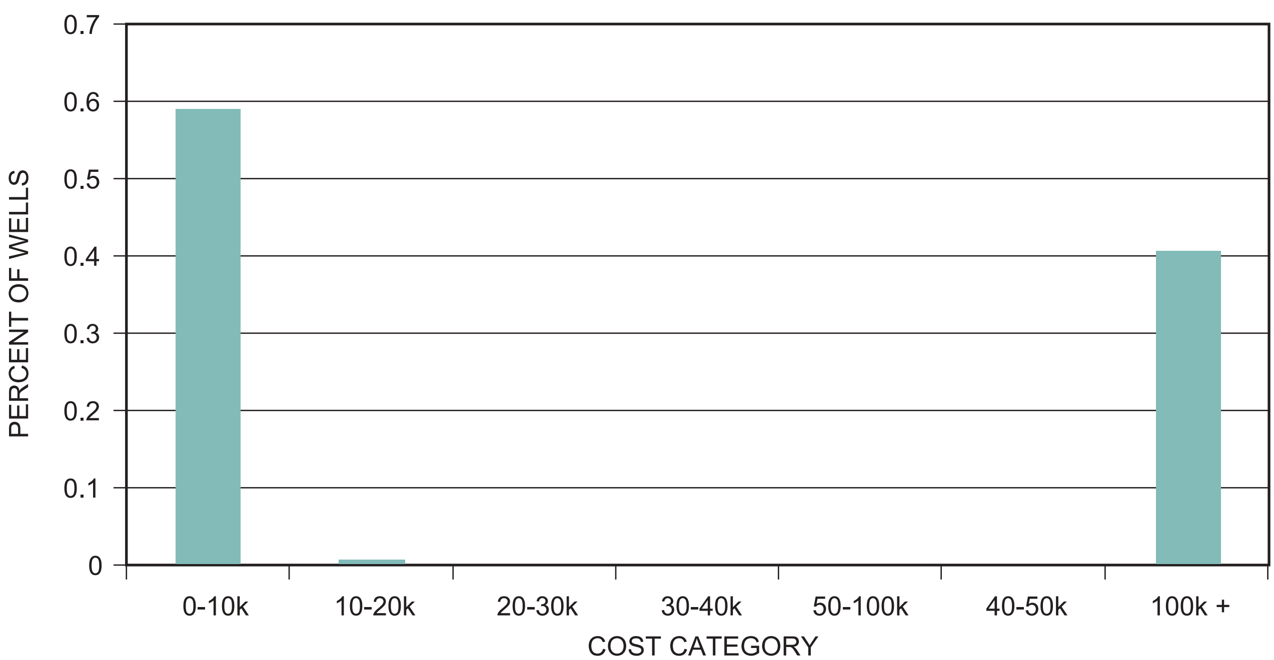
H.C. % = 29.9%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Green River Basin (All) – Exploratory Wells: Fee



Percent of Wells By Months of Seasonal Restrictions: Green River Basin (All)



Percent of Wells By Cost Category: Green River Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0		$15,802	$25,860	$33,157	$77,739		$158,632	$82,355
1								
2								
3								
4								
5			$29,800	$34,400		$45,900	$175,100	$105,613
6			$24,244	$34,500	$76,353	$42,628	$170,956	$94,491
7								
8								
9			$28,705	$36,157	$67,203	$44,736	$176,433	$105,534
10								
11								
12		$17,025	$26,500	$34,253	$78,274	$42,977	$173,924	$97,152
All		$16,064	$25,869	$34,250	$76,177	$43,495	$168,826	$92,684

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0		2.2%	9.1%	4.7%	1.8%		11.8%	29.6%
1								
2								
3								
4								
5			0.1%	0.2%		0.1%	0.4%	0.8%
6			2.4%	12.0%	2.3%	3.0%	14.2%	33.9%
7								
8								
9			0.2%	1.1%	1.2%	2.4%	4.0%	8.9%
10								0.0%
11								0.0%
12		0.6%	4.8%	5.4%	3.6%	1.2%	11.2%	26.8%
All		2.8%	16.6%	23.4%	8.9%	6.7%	41.6%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0								
3								
6		0.8%	4.1%	4.4%	1.6%	0.4%	8.7%	20.0%
9								
12		1.3%	6.0%	9.3%	3.4%	3.3%	16.6%	39.9%
18								
24								
36+		0.7%	6.5%	9.7%	3.9%	3.0%	16.3%	40.1%
All		2.8%	16.6%	23.4%	8.9%	6.7%	41.6%	100.0%

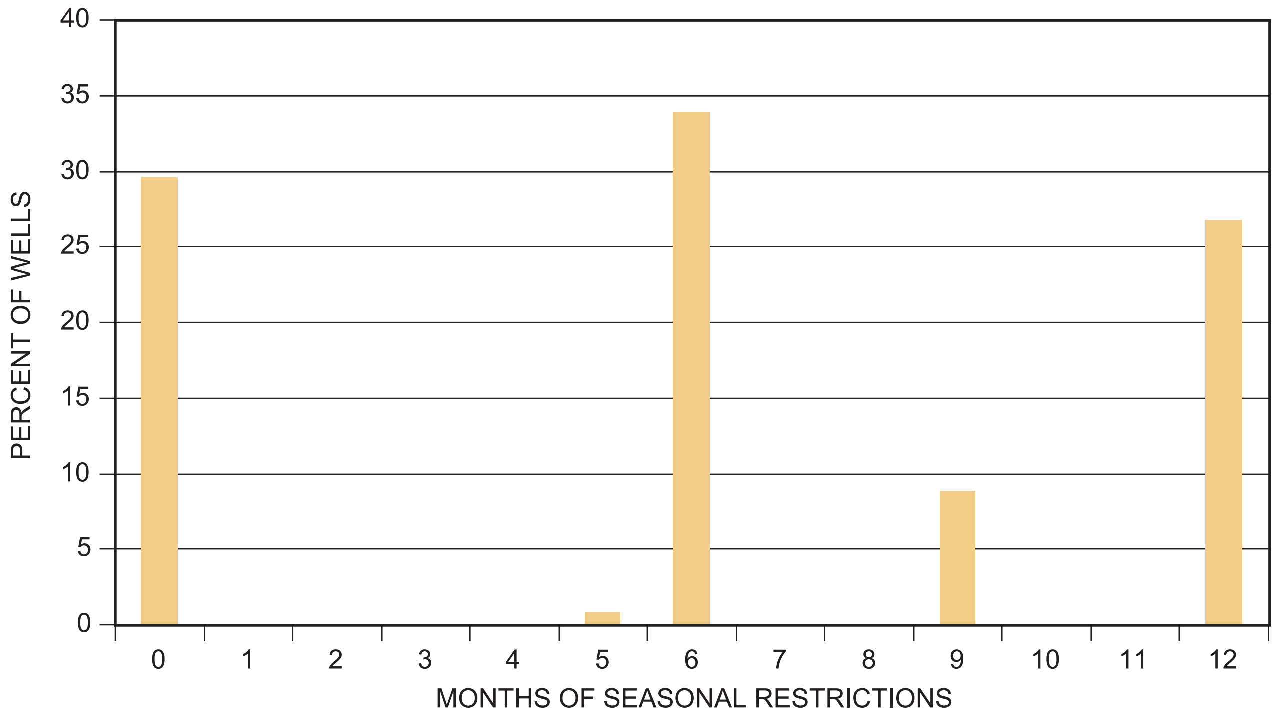
Unavailable Resources on Federal Lands

EPCA (Fed only)	NPC Addition	Total
12.0%	31.4%*	43.4%

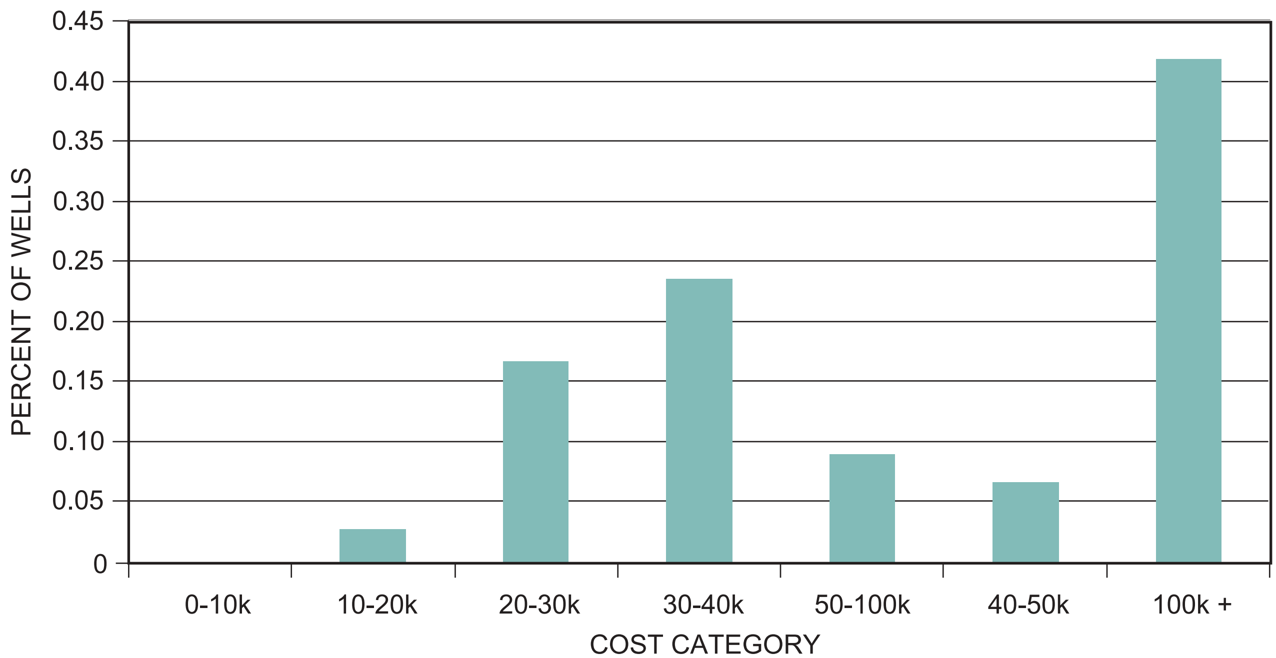
H.C. % =	23.2%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Green River Basin (All) – Development Wells: Federal



Percent of Wells By Months of Seasonal Restrictions: Green River Basin (All)



Percent of Wells By Cost Category: Green River Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0		$15,802	$25,860	$33,157	$77,739		$158,632	$82,355
1								
2								
3								
4								
5			$29,800	$34,400		$45,900	$175,100	$105,613
6			$24,244	$34,500	$76,353	$42,628	$170,956	$94,491
7								
8								
9			$28,705	$36,157	$67,203	$44,736	$176,433	$105,534
10								
11								
12		$17,025	$26,500	$34,253	$78,274	$42,977	$173,924	$97,152
All		$16,064	$25,869	$34,250	$76,177	$43,495	$168,826	$92,684

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0		2.2%	9.1%	4.7%	1.8%		11.8%	29.6%
1								
2								
3								
4								
5			0.1%	0.2%		0.1%	0.4%	0.8%
6			2.4%	12.0%	2.3%	3.0%	14.2%	33.9%
7								
8								
9			0.2%	1.1%	1.2%	2.4%	4.0%	8.9%
10								0.0%
11								0.0%
12		0.6%	4.8%	5.4%	3.6%	1.2%	11.2%	26.8%
All		2.8%	16.6%	23.4%	8.9%	6.7%	41.6%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0								
3								
6		0.8%	4.1%	4.4%	1.6%	0.4%	8.7%	20.0%
9								
12		1.3%	6.0%	9.3%	3.4%	3.3%	16.6%	39.9%
18								
24								
36+		0.7%	6.5%	9.7%	3.9%	3.0%	16.3%	40.1%
All		2.8%	16.6%	23.4%	8.9%	6.7%	41.6%	100.0%

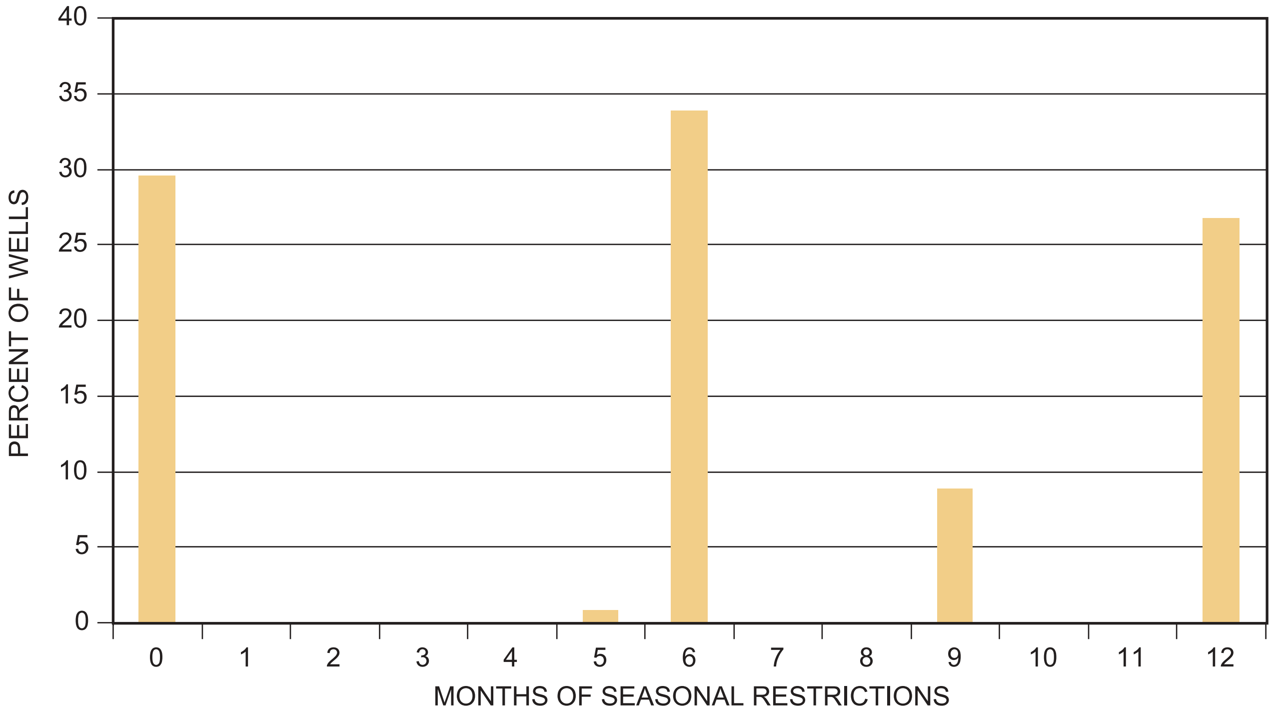
Unavailable Resources on State Lands

EPCA (Fed only)	NPC Addition	Total
0.0%	35.7%*	35.7%

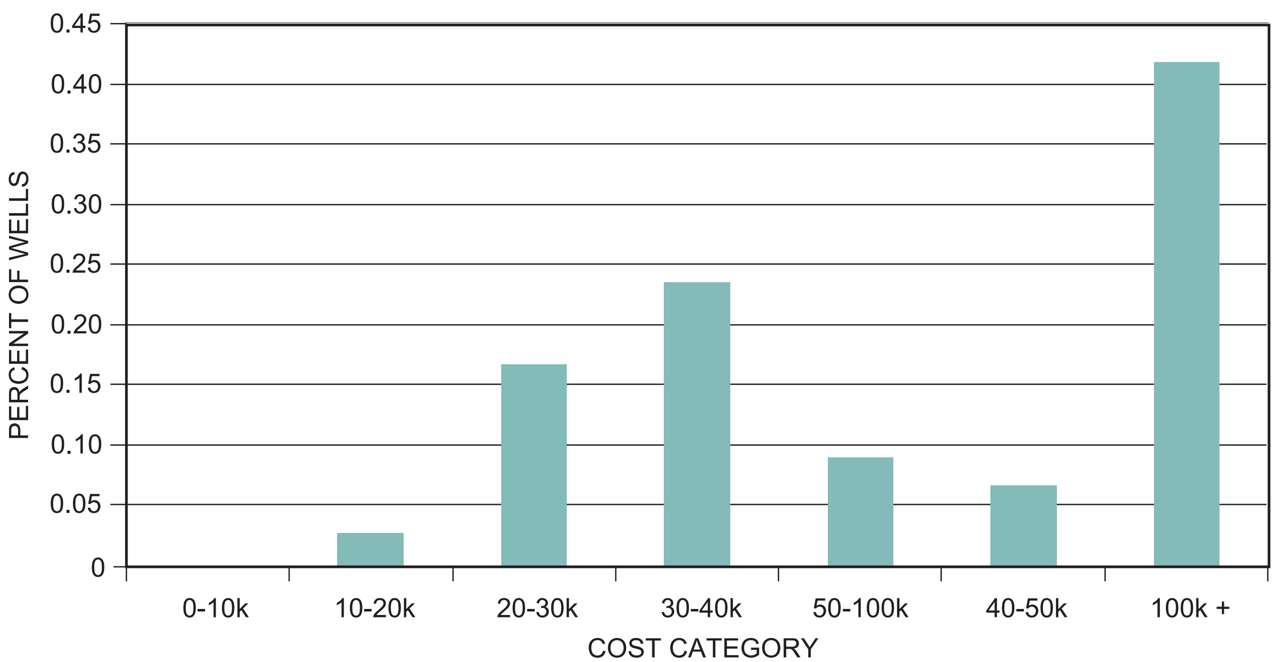
H.C. % =	26.4%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Green River Basin (All) – Development Wells: State



Percent of Wells By Months of Seasonal Restrictions: Green River Basin (All)



Percent of Wells By Cost Category: Green River Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	$2,139						$129,637	$53,251
1								
2								
3								
4								
5	$7,867						$131,950	$69,908
6	$8,000	$14,000					$134,162	$60,714
7								
8								
9								
10								
11								
12	$3,513	$14,000					$134,997	$56,087
All	$4,081	$14,000					$132,321	$56,196

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	27.2%						18.2%	45.4%
1								
2								
3								
4								
5	0.6%						0.6%	1.2%
6	15.2%	0.3%					11.1%	26.6%
7								
8								
9								
10								0.0%
11								0.0%
12	15.9%	0.2%					10.7%	26.8%
All	58.9%	0.5%					40.6%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

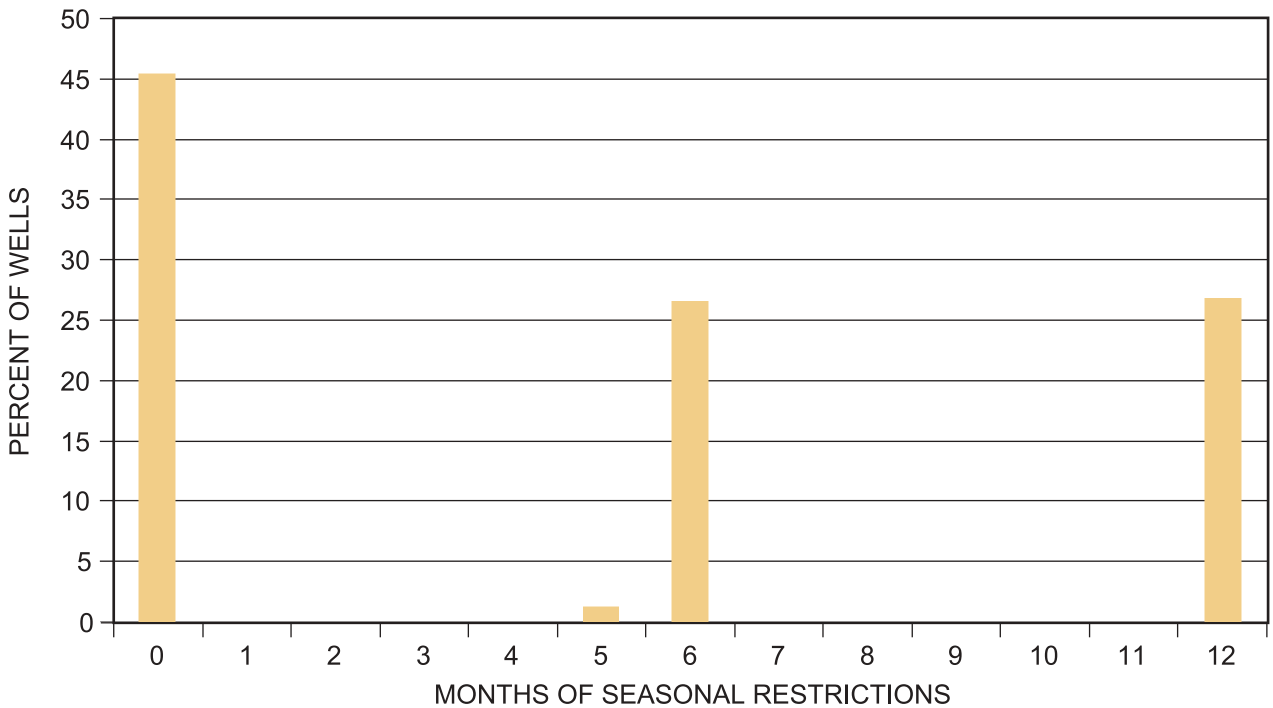
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	36.7%						11.8%	48.5%
3	22.2%	0.5%					28.4%	51.1%
6								
9								
12								
18								
24								
36+							0.4%	0.4%
All	58.9%	0.5%					40.6%	100.0%

Unavailable Resources on Fee Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
0.0%	26.8%*	26.8%

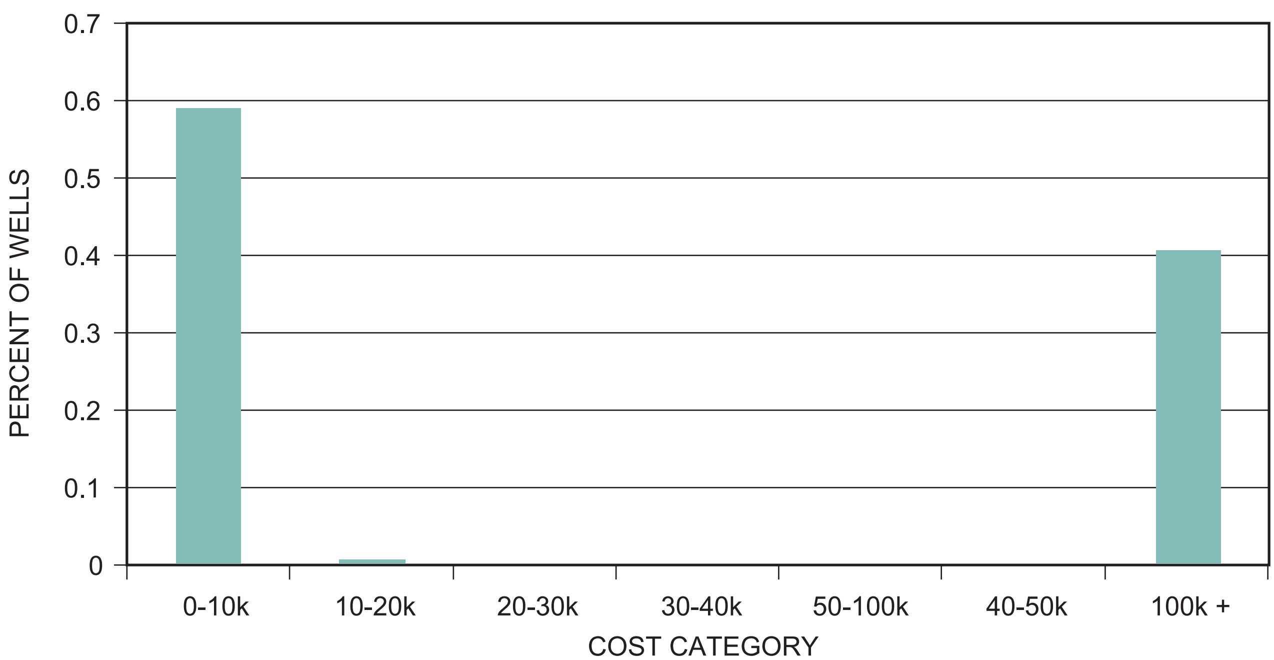
H.C. % =	29.9%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Green River Basin (All) – Development Wells: Fee



Percent of Wells By Months of Seasonal Restrictions: Green River Basin (All)



Percent of Wells By Cost Category: Green River Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	$9,098	$15,601	$24,064	$32,821	$74,323		$153,272	$63,766
1								
2								
3								
4								
5			$22,350					$22,350
6		$17,377	$24,630	$33,383	$84,747		$170,448	$74,899
7								
8								
9				$30,630				$30,630
10								
11								
12		$15,482	$23,439	$33,150	$68,929		$167,794	$73,050
All	$9,098	$15,647	$24,135	$33,019	$74,669		$156,067	$65,490

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	5.5%	31.5%	14.3%	0.7%	4.2%		26.4%	82.6%
1								
2								
3								
4								
5			0.1%					0.1%
6		1.0%	4.8%	1.0%	0.6%		3.5%	10.9%
7								
8								
9				0.1%				0.1%
10								0.0%
11								0.0%
12		1.7%	1.7%	0.1%	0.8%		2.0%	6.3%
All	5.5%	34.2%	20.9%	1.9%	5.6%		31.9%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0								
3								
6	5.5%	13.6%	7.6%	0.4%	1.5%		6.3%	34.9%
9		20.6%	13.3%	1.5%	4.1%		25.5%	65.0%
12								
18								
24								
36+							0.1%	0.1%
All	5.5%	34.2%	20.9%	1.9%	5.6%		31.9%	100.0%

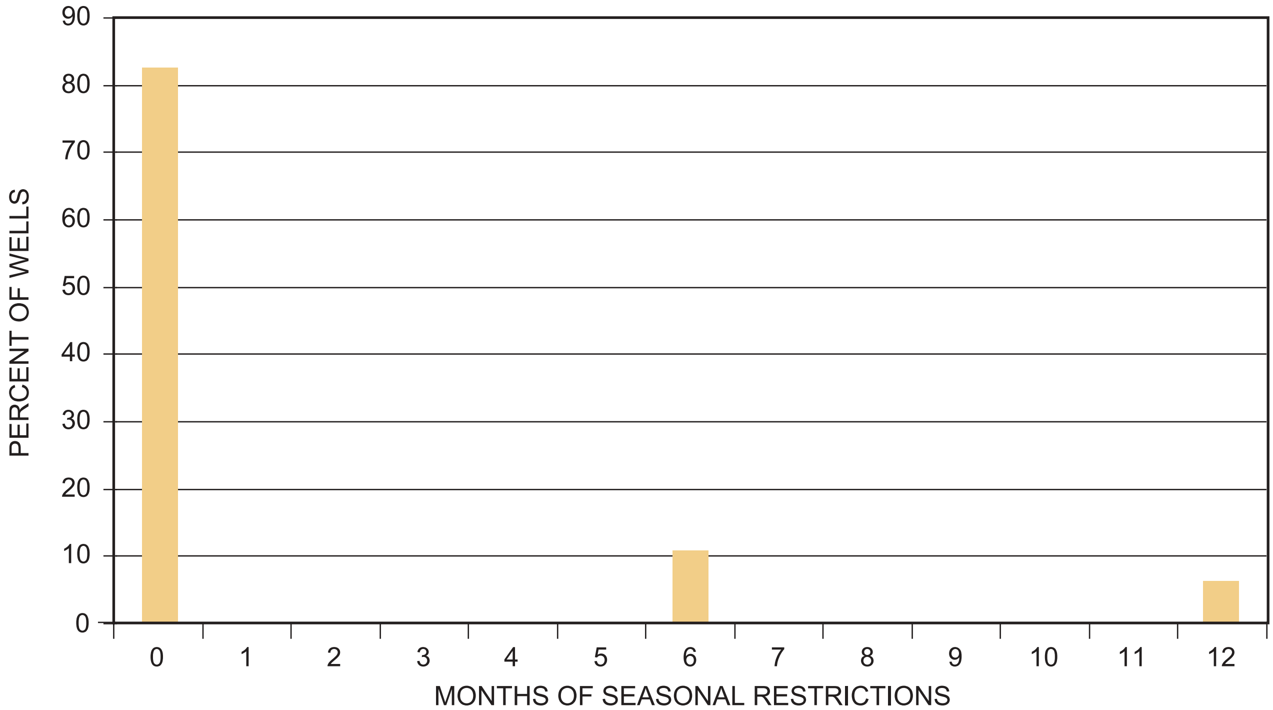
Unavailable Resources on Federal Lands

EPCA (Fed only)	NPC Addition	Total
4.7%	6.1%*	10.8%

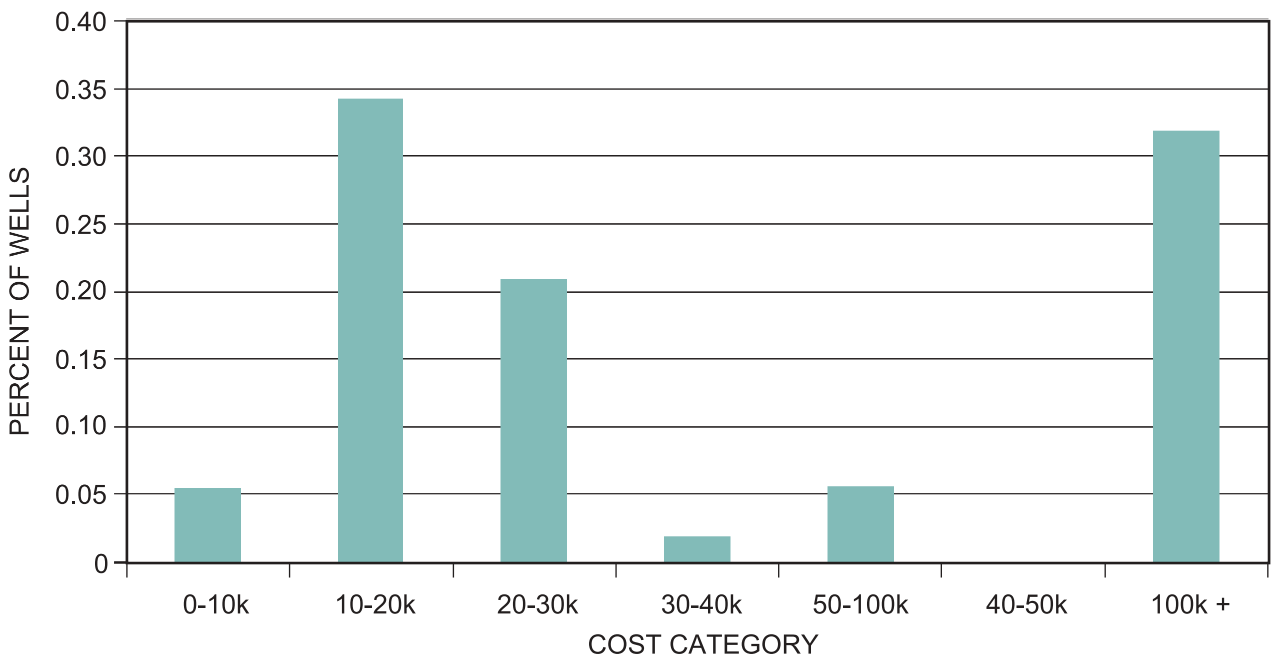
H.C. % = 28.5%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

San Juan Basin (All) – Exploratory Wells: Federal



Percent of Wells By Months of Seasonal Restrictions: San Juan Basin (All)



Percent of Wells By Cost Category: San Juan Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	$9,098	$15,601	$24,064	$32,821	$74,323		$153,272	$63,766
1								
2								
3								
4								
5			$22,350					$22,350
6		$17,377	$24,630	$33,383	$84,747		$170,448	$74,899
7								
8								
9				$30,630				$30,630
10								
11								
12		$15,482	$23,439	$33,150	$68,929		$167,794	$73,050
All	$9,098	$15,647	$24,135	$33,019	$74,669		$156,067	$65,490

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	5.5%	31.5%	14.3%	0.7%	4.2%		26.4%	82.6%
1								
2								
3								
4								
5			0.1%					0.1%
6		1.0%	4.8%	1.0%	0.6%		3.5%	10.9%
7								
8								
9				0.1%				0.1%
10								0.0%
11								0.0%
12		1.7%	1.7%	0.1%	0.8%		2.0%	6.3%
All	5.5%	34.2%	20.9%	1.9%	5.6%		31.9%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

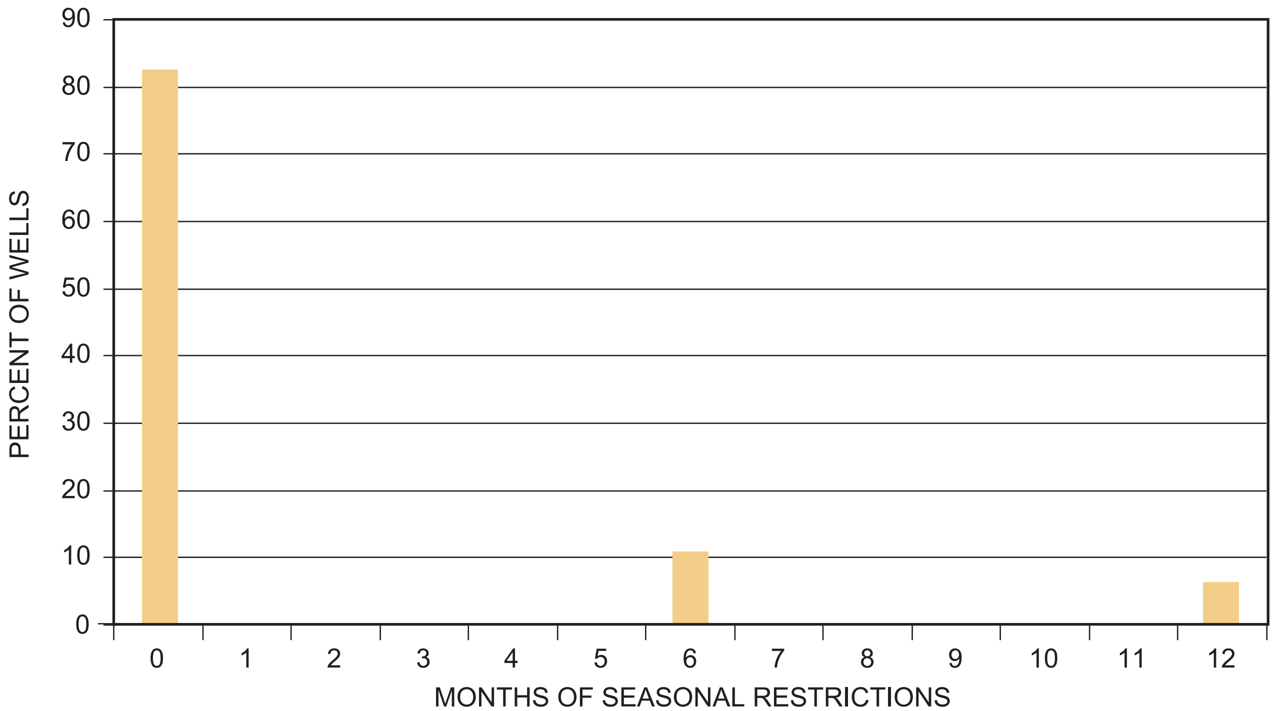
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0								
3								
6	5.5%	13.6%	7.6%	0.4%	1.5%		6.3%	34.9%
9		20.6%	13.3%	1.5%	4.1%		25.5%	65.0%
12								
18								
24								
36+							0.1%	0.1%
All	5.5%	34.2%	20.9%	1.9%	5.6%		31.9%	100.0%

Unavailable Resources on State Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
0.0%	6.4%*	6.4%

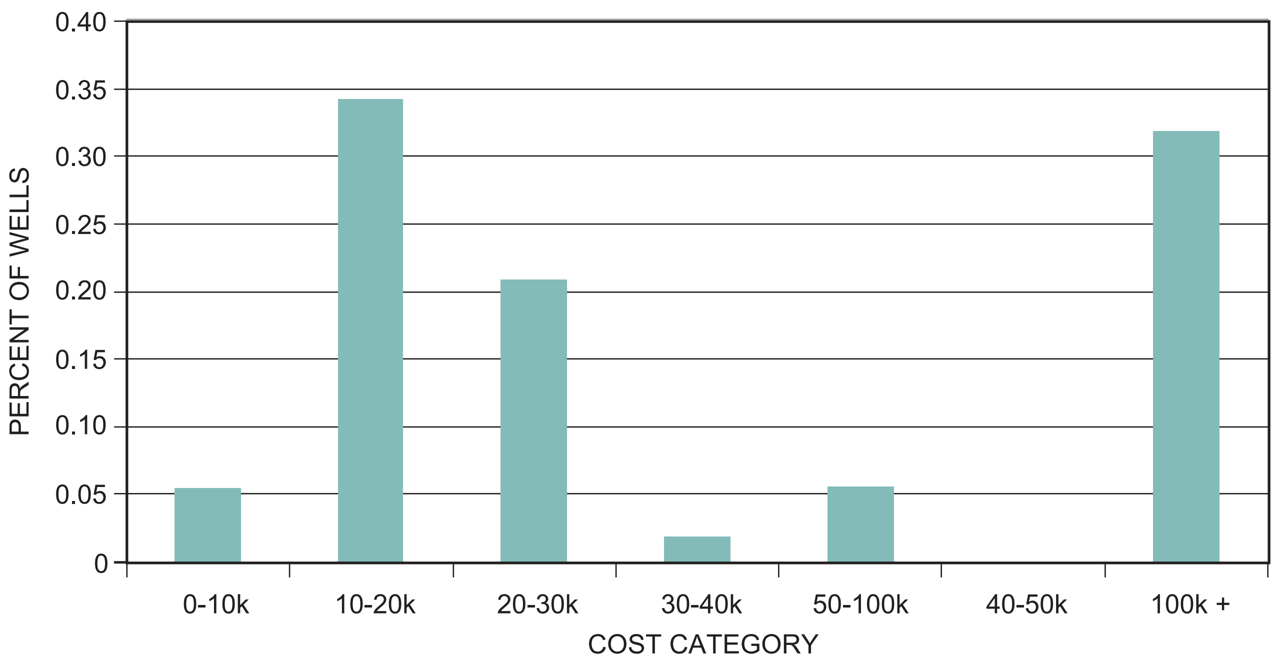
H.C. % =	29.9%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

San Juan Basin (All) – Exploratory Wells: State



Percent of Wells By Months of Seasonal Restrictions: San Juan Basin (All)



Percent of Wells By Cost Category: San Juan Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	$149						$108,549	$32,233
1								
2								
3								
4								
5	$6,100							$6,100
6	$6,092						$112,080	$37,265
7								
8								
9								
10								
11								
12	$796						$106,247	$29,251
All	$301						$108,476	$32,104

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	64.7%						27.2%	91.9%
1								
2								
3								
4								
5	0.1%							0.1%
6	1.2%						0.5%	1.7%
7								
8								
9								
10								0.0%
11								0.0%
12	4.6%						1.7%	6.3%
All	70.6%						29.4%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

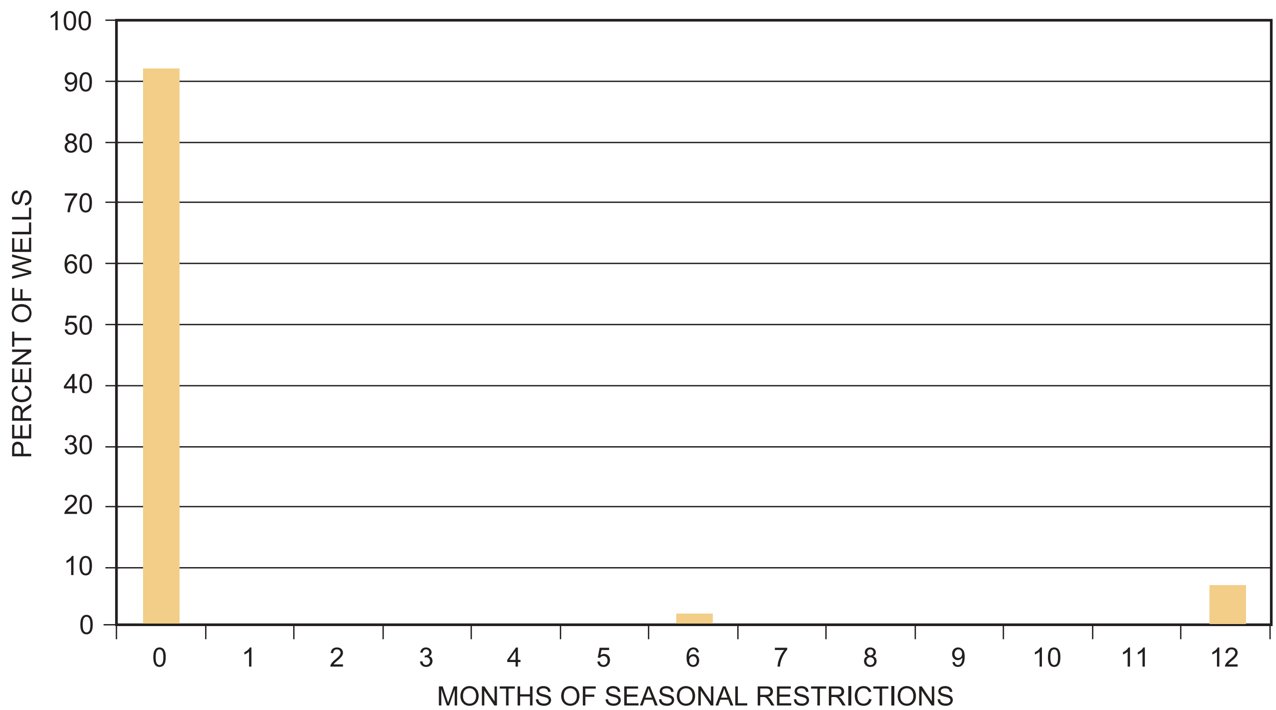
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	69.0%							69.0%
3	1.6%						29.3%	30.9%
6								
9								
12								
18								
24								
36+							0.1%	0.1%
All	70.6%						29.4%	100.0%

Unavailable Resources on Fee Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
0.0%	6.3%*	6.3%

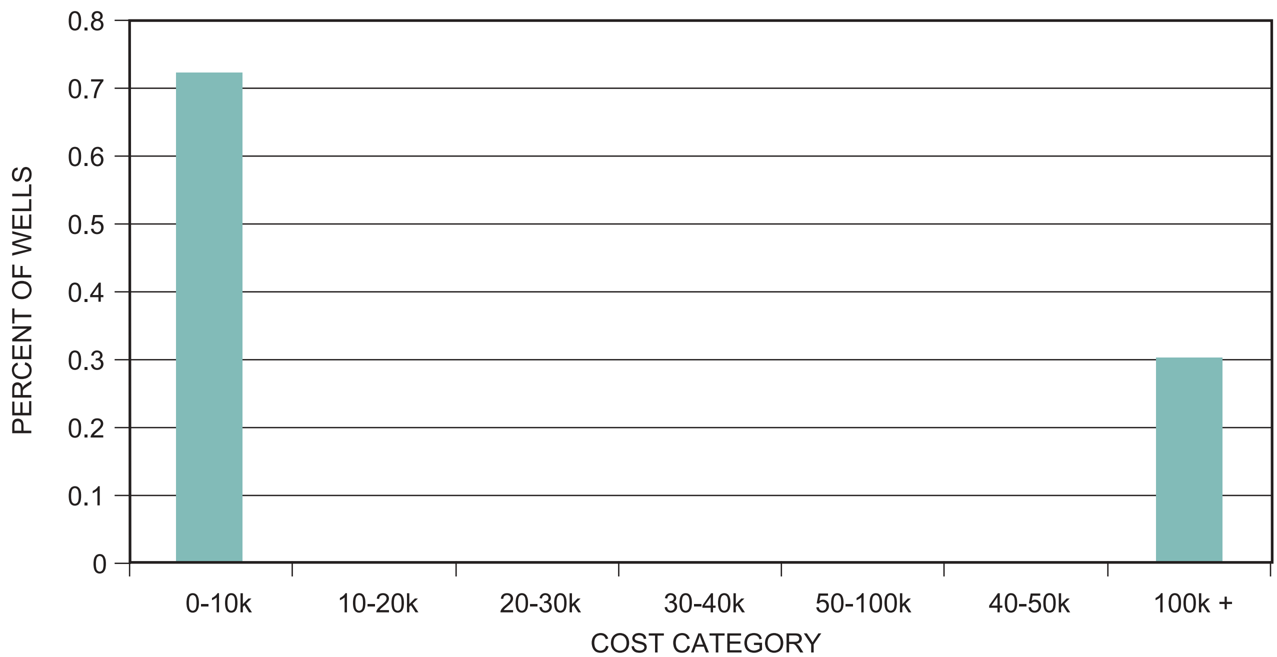
H.C. % =	27.7%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

San Juan Basin (All) – Exploratory Wells: Fee



Percent of Wells By Months of Seasonal Restrictions: San Juan Basin (All)



Percent of Wells By Cost Category: San Juan Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	$6,572	$13,267	$23,505	$31,800	$72,516		$138,894	$54,229
1								
2								
3								
4								
5		$16,650						$16,650
6	$9,400	$17,301	$24,995	$34,024	$79,792	$44,558	$153,696	$56,668
7								
8								
9			$29,730					$29,730
10								
11								
12	$8,219	$13,865	$23,437		$63,163		$154,964	$60,415
All	$6,649	$13,817	$23,841	$33,620	$71,626	$44,558	$141,074	$54,822

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	20.0%	23.5%	9.6%	0.2%	4.0%		25.3%	82.6%
1								
2								
3								
4								
5		0.1%						0.1%
6	0.1%	3.6%	2.6%	0.9%	0.6%	0.6%	2.5%	10.9%
7								
8								
9			0.1%					0.1%
10								0.0%
11								0.0%
12	0.8%	1.9%	0.9%		1.0%		1.7%	6.3%
All	20.9%	29.1%	13.2%	1.1%	5.6%	0.6%	29.5%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

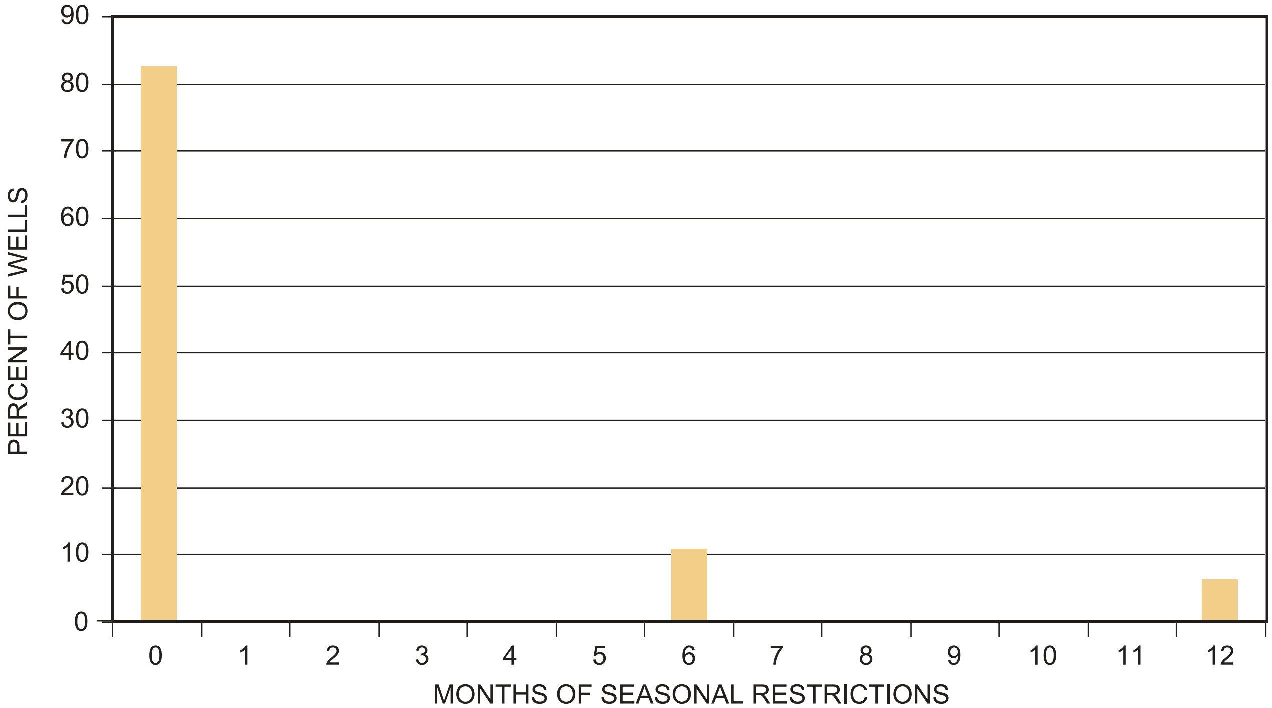
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0								
3								
6	20.0%	27.4%	12.2%	0.9%	5.3%	0.6%	27.6%	94.0%
9	0.5%	1.0%	0.3%	0.1%	0.3%		0.7%	2.9%
12								
18								
24	0.4%	0.7%	0.7%	0.1%			1.1%	3.0%
36+							0.1%	0.1%
All	20.9%	29.1%	13.2%	1.1%	5.6%	0.6%	29.5%	100.0%

Unavailable Resources on Federal Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
4.7%	6.1%*	10.8%

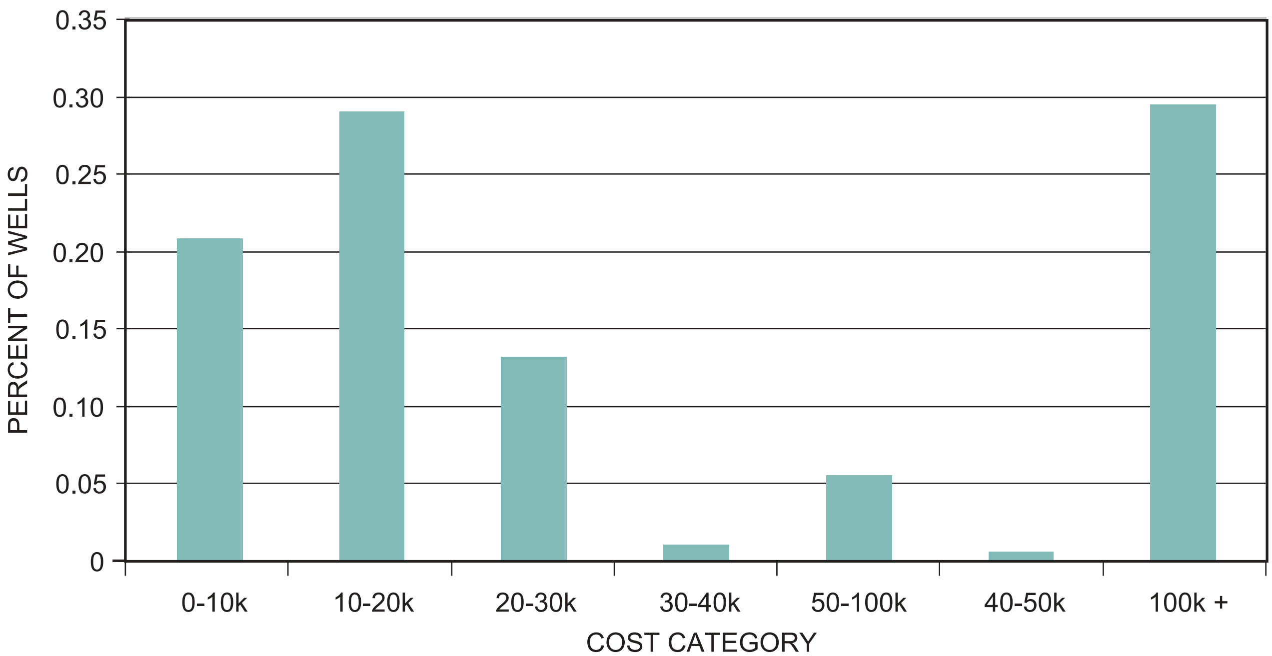
H.C. % =	26.5%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

San Juan Basin (All) – Development Wells: Federal



Percent of Wells By Months of Seasonal Restrictions: San Juan Basin (All)



Percent of Wells By Cost Category: San Juan Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	$6,572	$13,267	$23,505	$31,800	$72,516		$138,894	$54,229
1								
2								
3								
4								
5		$16,650						$16,650
6	$9,400	$17,301	$24,995	$34,024	$79,792	$44,558	$153,696	$56,668
7								
8								
9			$29,730					$29,730
10								
11								
12	$8,219	$13,865	$23,437		$63,163		$154,964	$60,415
All	$6,649	$13,817	$23,841	$33,620	$71,626	$44,558	$141,074	$54,822

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	20.0%	23.5%	9.6%	0.2%	4.0%		25.3%	82.6%
1								
2								
3								
4								
5		0.1%						0.1%
6	0.1%	3.6%	2.6%	0.9%	0.6%	0.6%	2.5%	10.9%
7								
8								
9			0.1%					0.1%
10								0.0%
11								0.0%
12	0.8%	1.9%	0.9%		1.0%		1.7%	6.3%
All	20.9%	29.1%	13.2%	1.1%	5.6%	0.6%	29.5%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

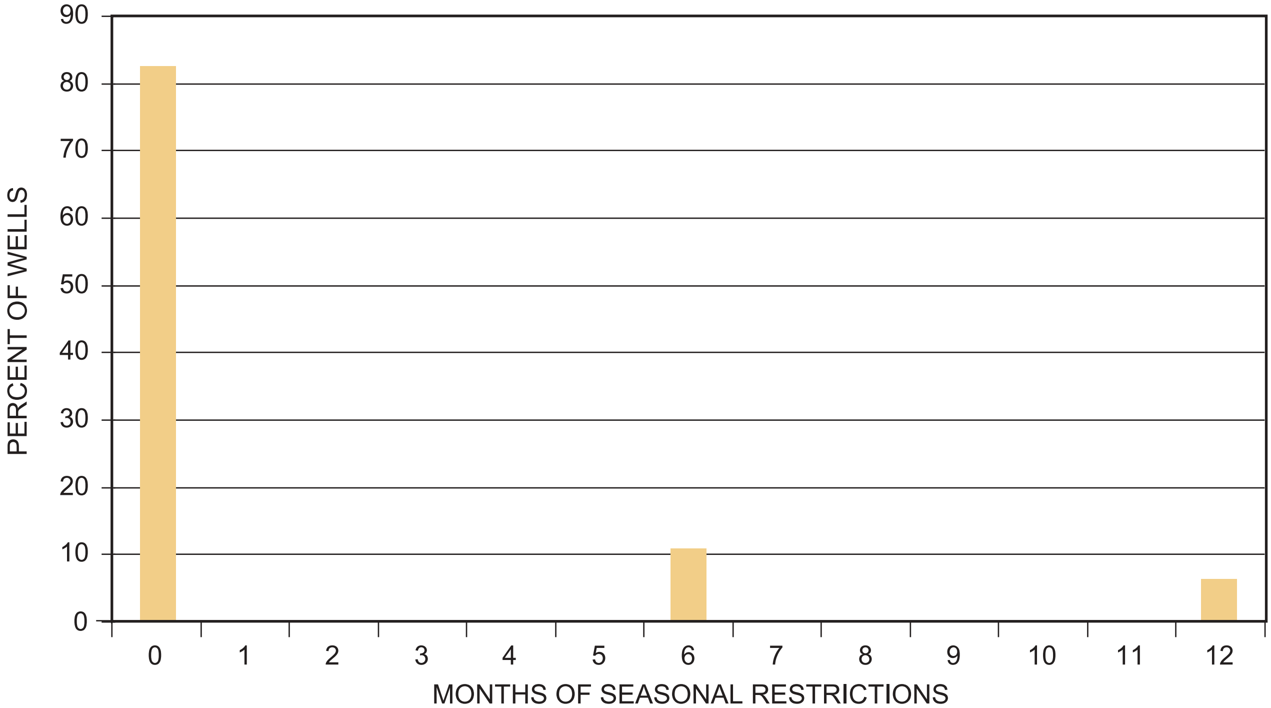
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0								
3								
6	20.0%	27.4%	12.2%	0.9%	5.3%	0.6%	27.6%	94.0%
9	0.5%	1.0%	0.3%	0.1%	0.3%		0.7%	2.9%
12								
18								
24	0.4%	0.7%	0.7%	0.1%			1.1%	3.0%
36+							0.1%	0.1%
All	20.9%	29.1%	13.2%	1.1%	5.6%	0.6%	29.5%	100.0%

Unavailable Resources on State Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
0.0%	6.4%*	6.4%

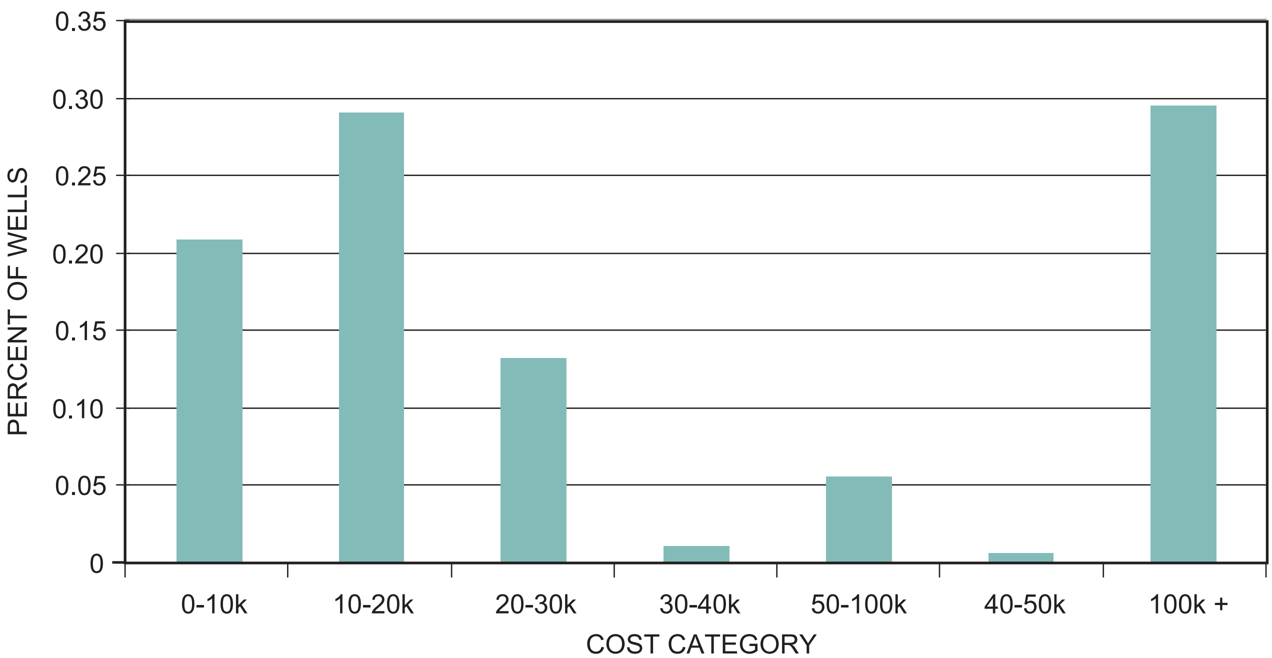
H.C. % =	27.8%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

San Juan Basin (All) – Development Wells: State



Percent of Wells By Months of Seasonal Restrictions: San Juan Basin (All)



Percent of Wells By Cost Category: San Juan Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	$248						$108,964	$32,425
1								
2								
3								
4								
5	$6,200							$6,200
6	$6,183						$112,160	$37,353
7								
8								
9								
10								
11								
12	$896						$106,347	$29,351
All	$399						$108,867	$32,289

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	64.7%						27.2%	91.9%
1								
2								
3								
4								
5	0.1%							0.1%
6	1.2%						0.5%	1.7%
7								
8								
9								
10								0.0%
11								0.0%
12	4.6%						1.7%	6.3%
All	70.6%						29.4%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	69.0%							69.0%
3	1.6%						29.3%	30.9%
6								
9								
12								
18								
24								
36+							0.1%	0.1%
All	70.6%						29.4%	100.0%

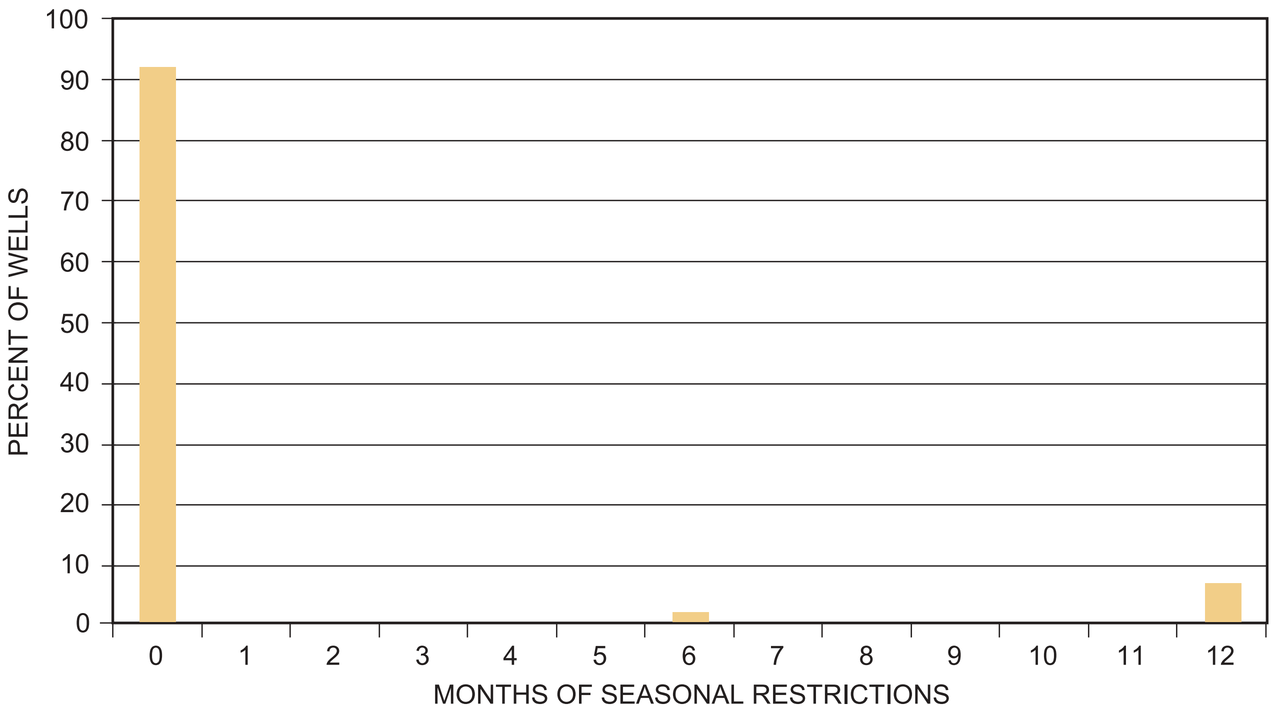
Unavailable Resources on Fee Lands

EPCA (Fed only)	NPC Addition	Total
0.0%	6.3%*	6.3%

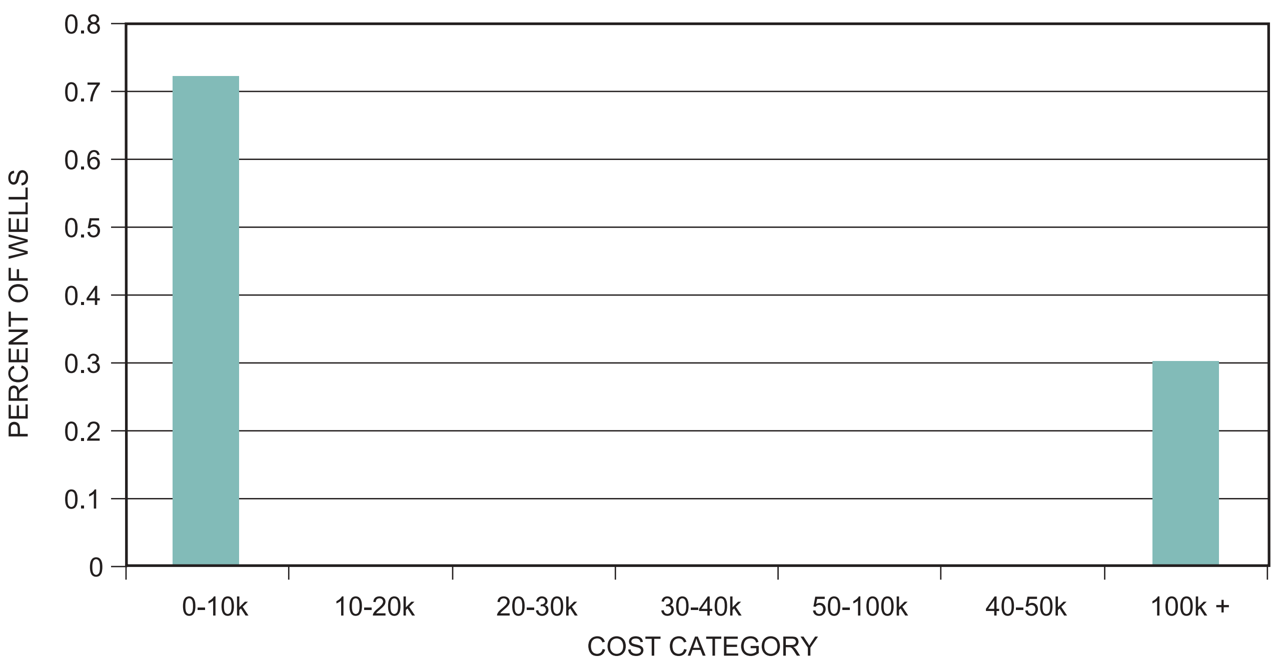
H.C. % =	27.7%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

San Juan Basin (All) – Development Wells: Fee



Percent of Wells By Months of Seasonal Restrictions: San Juan Basin (All)



Percent of Wells By Cost Category: San Juan Basin (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0		$16,433	$24,758	$34,100	$70,347	$42,350	$222,577	$141,524
1								
2								
3								
4								
5					$83,350			$83,350
6		$18,630	$26,352	$35,191	$77,016	$44,457	$230,038	$165,779
7								
8								
9					$83,693	$43,680	$192,684	$143,937
10								
11								
12		$19,625	$26,895	$35,365	$75,936	$43,540	$191,528	$135,735
All		$16,910	$25,483	$34,800	$73,586	$43,692	$219,652	$149,244

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0		1.5%	3.0%	2.2%	15.3%	0.5%	23.6%	46.1%
1								
2								
3								
4								
5					0.1%			0.1%
6		0.1%	1.2%	2.2%	9.2%	1.0%	21.9%	35.6%
7								
8								
9					0.8%	0.2%	1.4%	2.4%
10								0.0%
11								0.0%
12		0.2%	0.8%	1.2%	3.8%	0.6%	9.2%	15.8%
All		1.8%	5.0%	5.6%	29.2%	2.3%	56.1%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

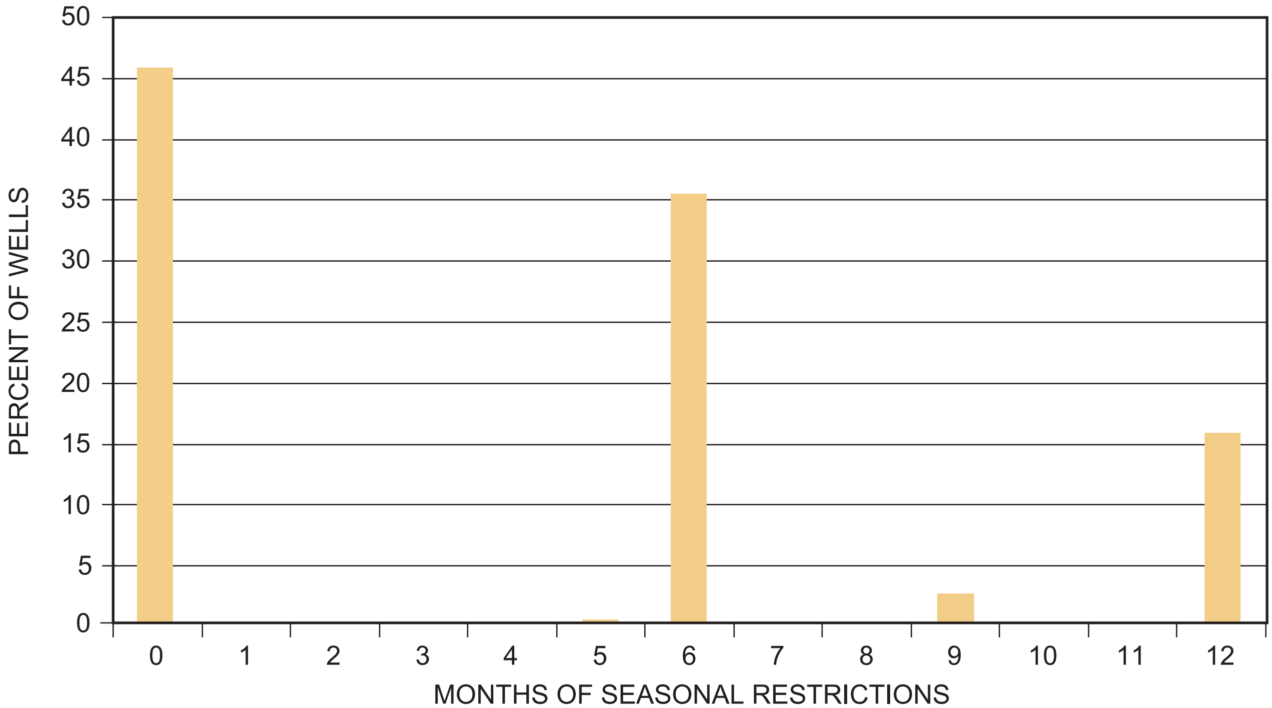
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0								
3								
6		0.6%	1.1%	0.8%	0.2%	0.4%	2.5%	5.6%
9		1.2%	3.9%	4.8%	0.7%	1.9%	15.7%	28.2%
12					28.3%		36.7%	65.0%
18								
24								
36+							1.2%	1.2%
All		1.8%	5.0%	5.6%	29.2%	2.3%	56.1%	100.0%

Unavailable Resources on Federal Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
7.2%	16.9%*	24.1%

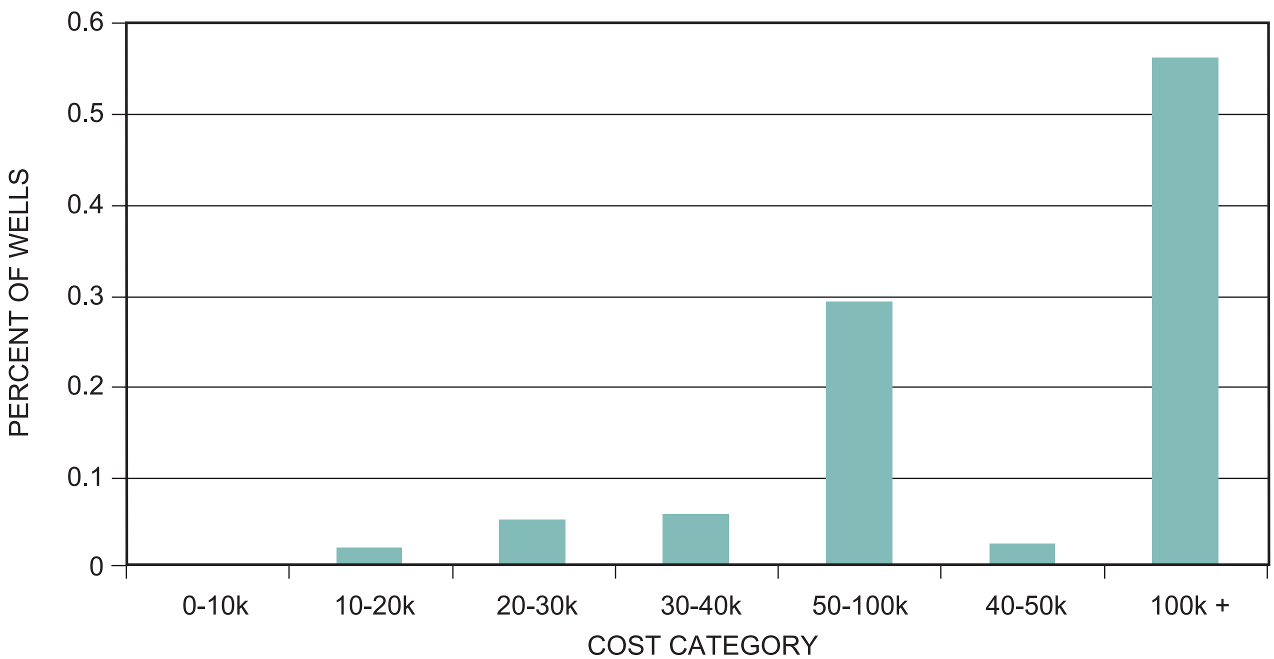
H.C. % =	42.2%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Uinta-Piceance Basin (All) – Exploratory Wells: Federal



Percent of Wells By Months of Seasonal Restrictions: Uinta-Piceance (All)



Percent of Wells By Cost Category: Uinta-Piceance (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0		$16,433	$24,758	$34,100	$70,347	$42,350	$222,577	$141,524
1								
2								
3								
4								
5					$83,350			$83,350
6		$18,630	$26,352	$35,191	$77,016	$44,457	$230,038	$165,779
7								
8								
9					$83,693	$43,680	$192,684	$143,937
10								
11								
12		$19,625	$26,895	$35,365	$75,936	$43,540	$191,528	$135,735
All		$16,910	$25,483	$34,800	$73,586	$43,692	$219,652	$149,244

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0		1.5%	3.0%	2.2%	15.3%	0.5%	23.6%	46.1%
1								
2								
3								
4								
5					0.1%			0.1%
6		0.1%	1.2%	2.2%	9.2%	1.0%	21.9%	35.6%
7								
8								
9					0.8%	0.2%	1.4%	2.4%
10								0.0%
11								0.0%
12		0.2%	0.8%	1.2%	3.8%	0.6%	9.2%	15.8%
All		1.8%	5.0%	5.6%	29.2%	2.3%	56.1%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

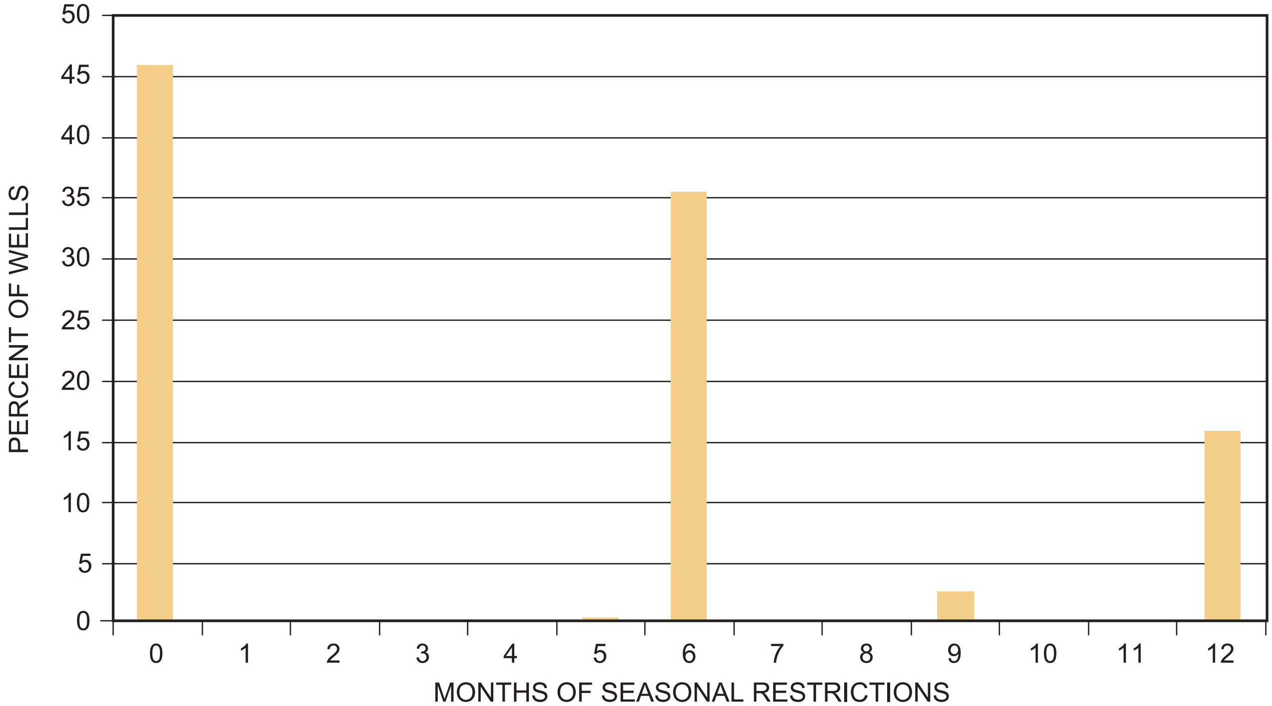
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0								
3								
6		0.6%	1.1%	0.8%	0.2%	0.4%	2.5%	5.6%
9		1.2%	3.9%	4.8%	0.7%	1.9%	15.7%	28.2%
12					28.3%		36.7%	65.0%
18								
24								
36+							1.2%	1.2%
All		1.8%	5.0%	5.6%	29.2%	2.3%	56.1%	100.0%

Unavailable Resources on State Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
0.0%	18.2%*	18.2%

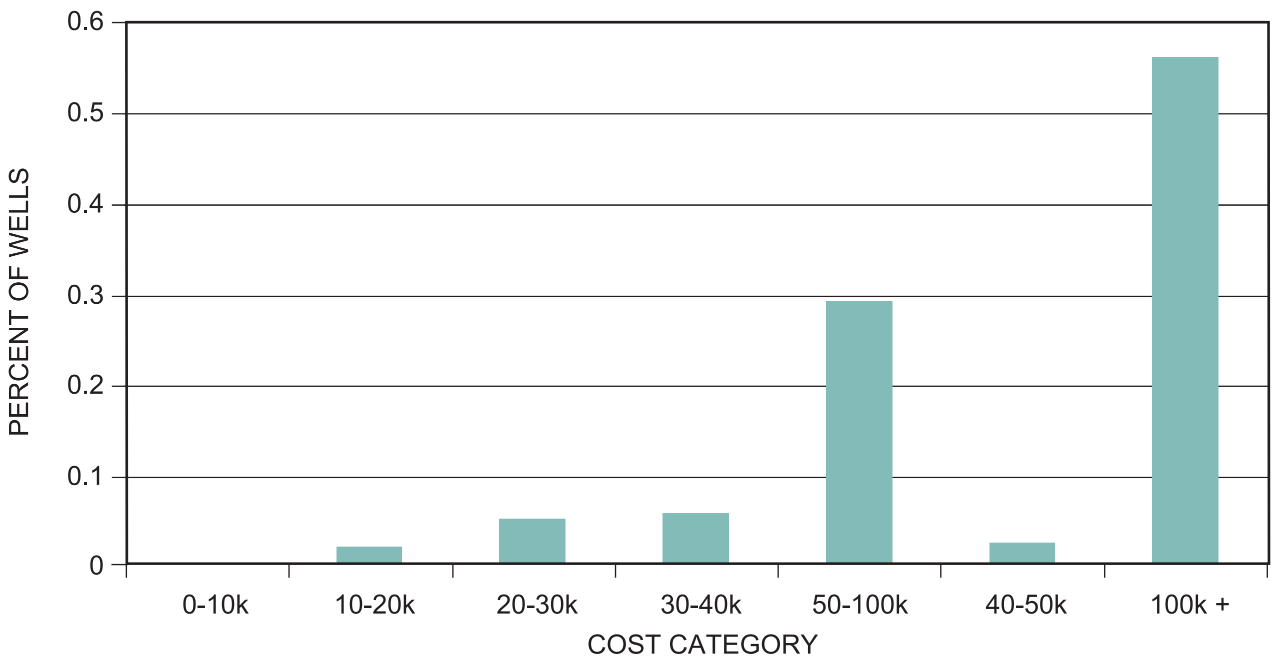
H.C. % =	45.5%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Uinta-Piceance Basin (All) – Exploratory Wells: State



Percent of Wells By Months of Seasonal Restrictions: Uinta-Piceance (All)



Percent of Wells By Cost Category: Uinta-Piceance (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	$1,135						$110,785	$55,960
1								
2								
3								
4								
5	$7,350							$7,350
6	$5,100						$111,097	$54,786
7								
8								
9								
10								
11								
12	$1,553						$107,757	$54,655
All	$1,494						$110,323	$55,582

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	38.8%						38.8%	77.6%
1								
2								
3								
4								
5	0.2%							0.2%
6	3.4%						3.0%	6.4%
7								
8								
9								
10								0.0%
11								0.0%
12	7.9%						7.9%	15.8%
All	50.3%						49.7%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

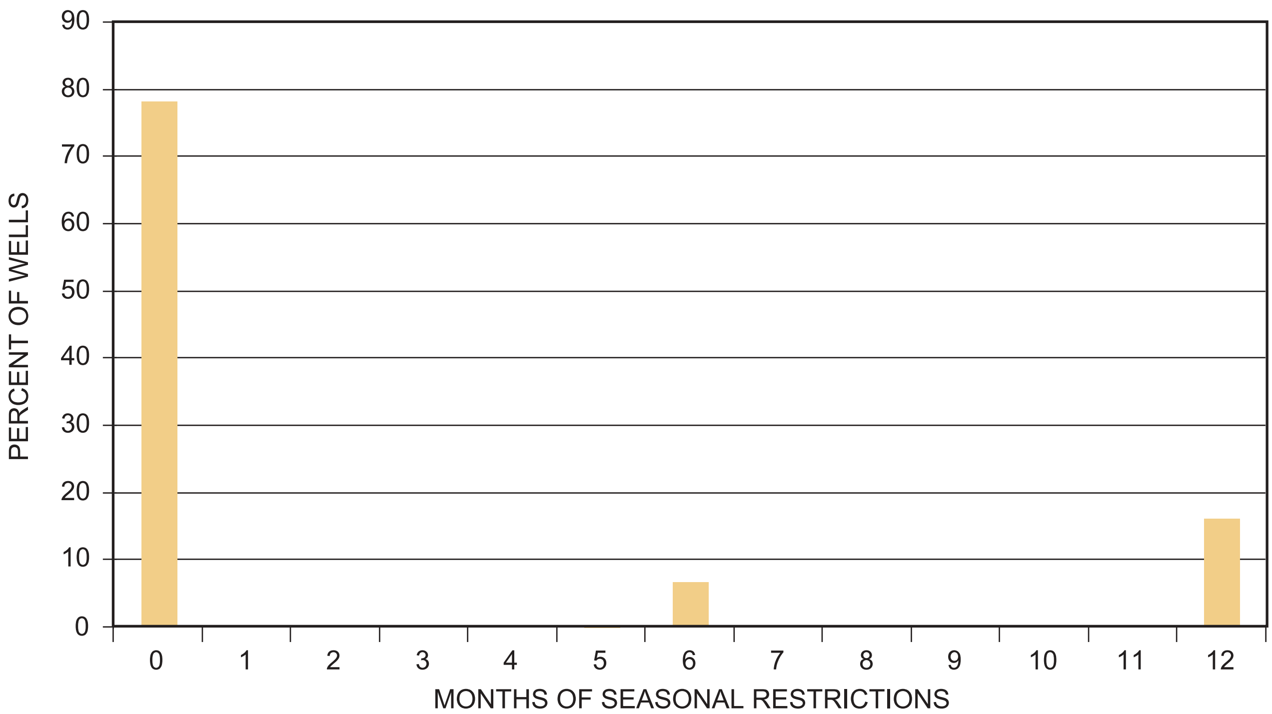
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	42.9%							42.9%
3	7.4%						49.5%	56.9%
6								
9								
12								
18								
24								
36+							0.2%	0.2%
All	50.3%						49.7%	100.0%

Unavailable Resources on Fee Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
0.0%	15.8%*	15.8%

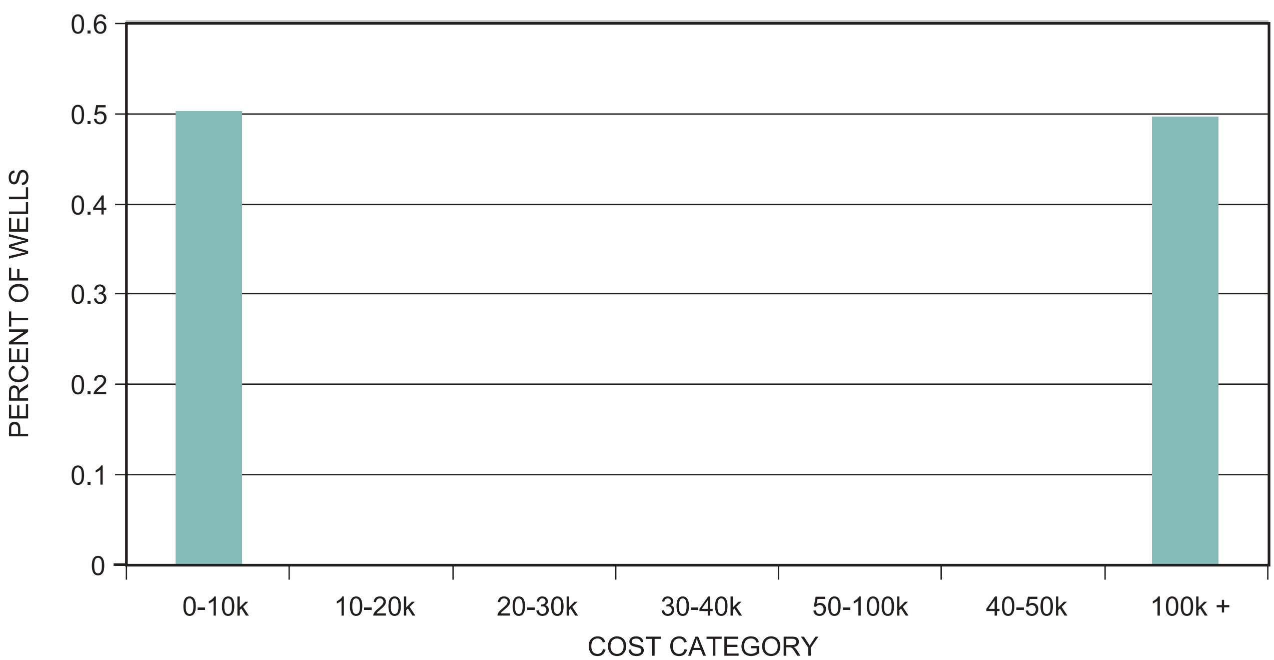
H.C. % =	41.8%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Uinta-Piceance Basin (All) – Exploratory Wells: Fee



Percent of Wells By Months of Seasonal Restrictions: Uinta-Piceance (All)



Percent of Wells By Cost Category: Uinta-Piceance (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	$6,524	$16,001	$24,581	$34,729	$78,387	$42,450	$175,291	$97,417
1								
2								
3								
4								
5				$33,480				$33,480
6		$17,246	$25,266	$35,027	$73,294	$44,024	$184,454	$116,726
7								
8								
9			$29,130	$35,978	$67,863	$44,148	$178,162	$101,952
10								
11								
12	$9,980	$16,543	$25,928	$34,566	$70,722	$45,723	$179,415	$110,443
All	$6,728	$16,278	$25,009	$34,881	$73,719	$44,430	$179,502	$106,394

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	1.6%	7.8%	9.1%	3.8%	1.5%	0.2%	22.1%	46.1%
1								
2								
3								
4								
5				0.1%				0.1%
6		1.9%	4.6%	4.9%	2.5%	2.5%	19.2%	35.6%
7								
8								
9			0.1%	0.4%	0.4%	0.5%	1.0%	2.4%
10								0.0%
11								0.0%
12	0.1%	1.2%	2.5%	1.4%	1.2%	1.2%	8.2%	15.8%
All	1.7%	10.9%	16.3%	10.6%	5.6%	4.4%	50.5%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

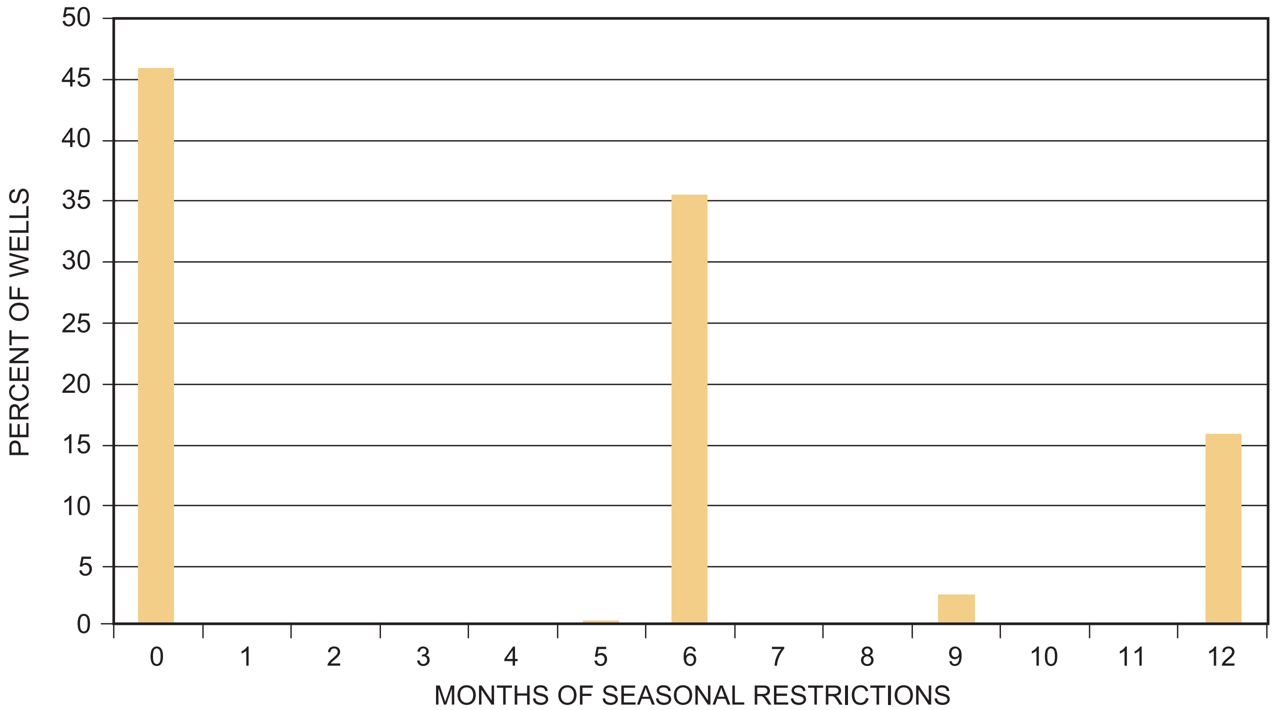
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0								
3								
6	1.4%	6.3%	10.7%	5.9%	2.9%	2.1%	30.6%	59.9%
9	0.2%	4.1%	4.7%	4.1%	2.3%	2.2%	17.3%	34.9%
12								
18								
24								
36+	0.1%	0.5%	0.9%	0.6%	0.4%	0.1%	2.6%	5.2%
All	1.7%	10.9%	16.3%	10.6%	5.6%	4.4%	50.5%	100.0%

Unavailable Resources on Federal Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
7.2%	16.9%*	24.1%

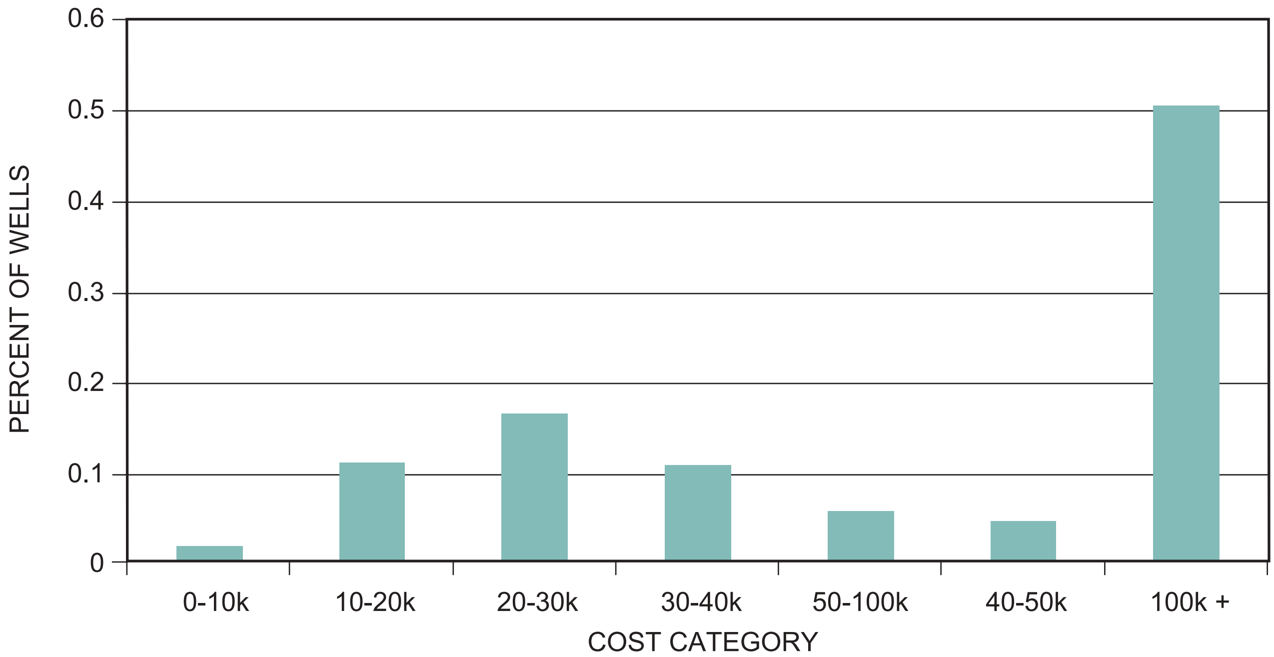
H.C. % =	38.3%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Uinta-Piceance Basin (All) – Development Wells: Federal



Percent of Wells By Months of Seasonal Restrictions: Uinta-Piceance (All)



Percent of Wells By Cost Category: Uinta-Piceance (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	$6,524	$16,001	$24,581	$34,729	$78,387	$42,450	$175,291	$97,417
1								
2								
3								
4								
5				$33,480				$33,480
6		$17,246	$25,266	$35,027	$73,294	$44,024	$184,454	$116,726
7								
8								
9			$29,130	$35,978	$67,863	$44,148	$178,162	$101,952
10								
11								
12	$9,980	$16,543	$25,928	$34,566	$70,722	$45,723	$179,415	$110,443
All	$6,728	$16,278	$25,009	$34,881	$73,719	$44,430	$179,502	$106,394

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	1.6%	7.8%	9.1%	3.8%	1.5%	0.2%	22.1%	46.1%
1								
2								
3								
4								
5				0.1%				0.1%
6		1.9%	4.6%	4.9%	2.5%	2.5%	19.2%	35.6%
7								
8								
9			0.1%	0.4%	0.4%	0.5%	1.0%	2.4%
10								0.0%
11								0.0%
12	0.1%	1.2%	2.5%	1.4%	1.2%	1.2%	8.2%	15.8%
All	1.7%	10.9%	16.3%	10.6%	5.6%	4.4%	50.5%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

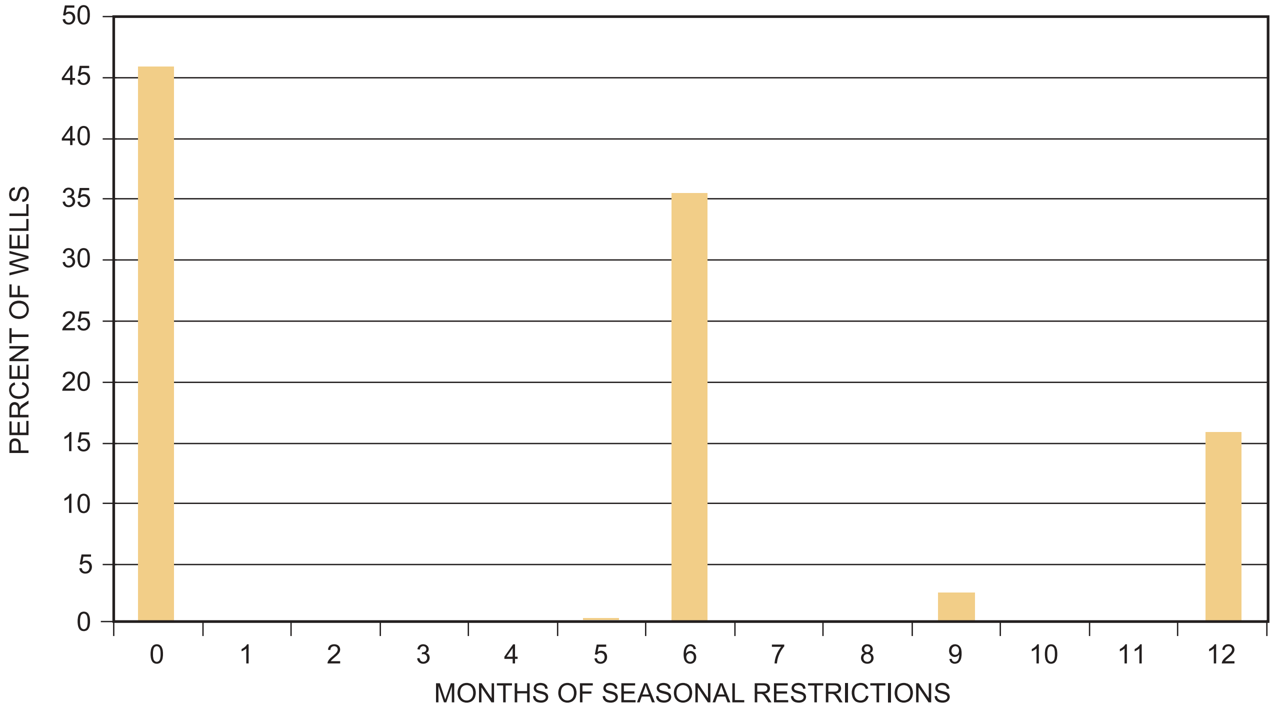
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0								
3								
6	1.4%	6.3%	10.7%	5.9%	2.9%	2.1%	30.6%	59.9%
9	0.2%	4.1%	4.7%	4.1%	2.3%	2.2%	17.3%	34.9%
12								
18								
24								
36+	0.1%	0.5%	0.9%	0.6%	0.4%	0.1%	2.6%	5.2%
All	1.7%	10.9%	16.3%	10.6%	5.6%	4.4%	50.5%	100.0%

Unavailable Resources on State Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
0.0%	18.2%*	18.2%

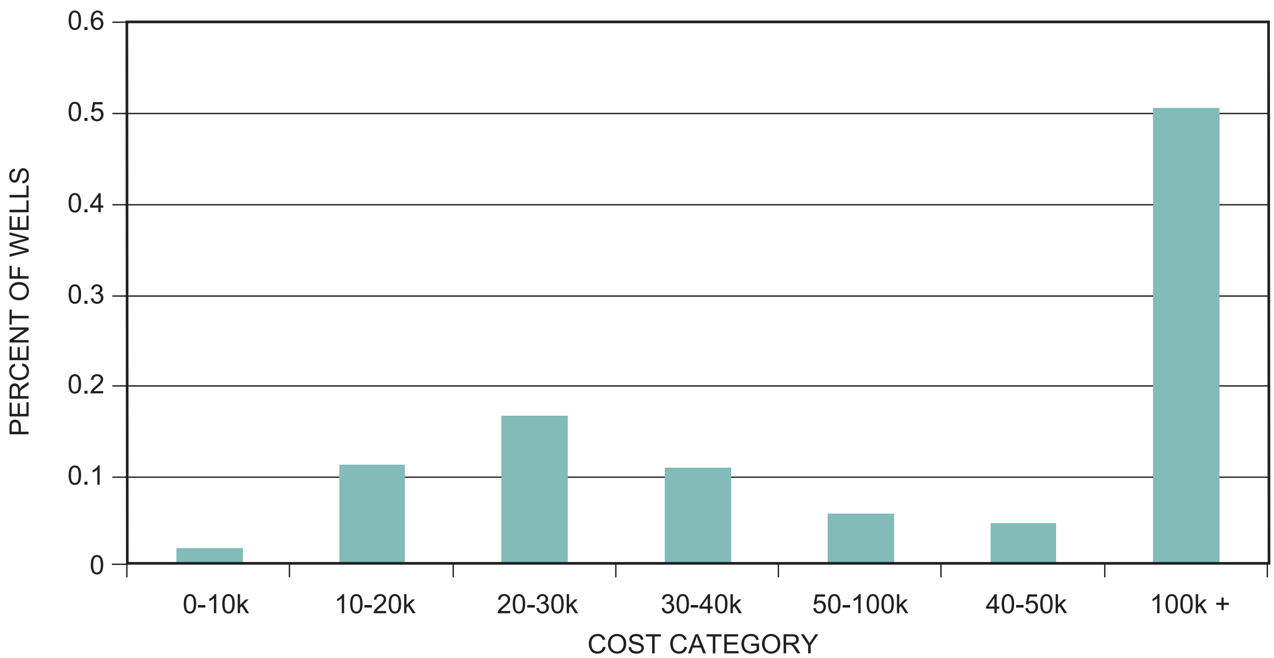
H.C. % =	41.3%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Uinta-Piceance Basin (All) – Development Wells: State



Percent of Wells By Months of Seasonal Restrictions: Uinta-Piceance (All)



Percent of Wells By Cost Category: Uinta-Piceance (All)

Average Added Well Costs By Number of Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	$1,233						$138,406	$69,819
1								
2								
3								
4								
5	$7,450							$7,450
6	$8,000						$146,293	$72,825
7								
8								
9								
10								
11								
12	$1,863						$135,580	$68,722
All	$1,814						$138,433	$69,714

Percent of Wells By Costs Category and Months of Seasonal Restrictions

	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	38.8%						38.8%	77.6%
1								
2								
3								
4								
5	0.2%							0.2%
6	3.4%						3.0%	6.4%
7								
8								
9								
10								0.0%
11								0.0%
12	7.9%						7.9%	15.8%
All	50.3%						49.7%	100.0%

Percent of Wells By Costs Category and Months of Processing Delay

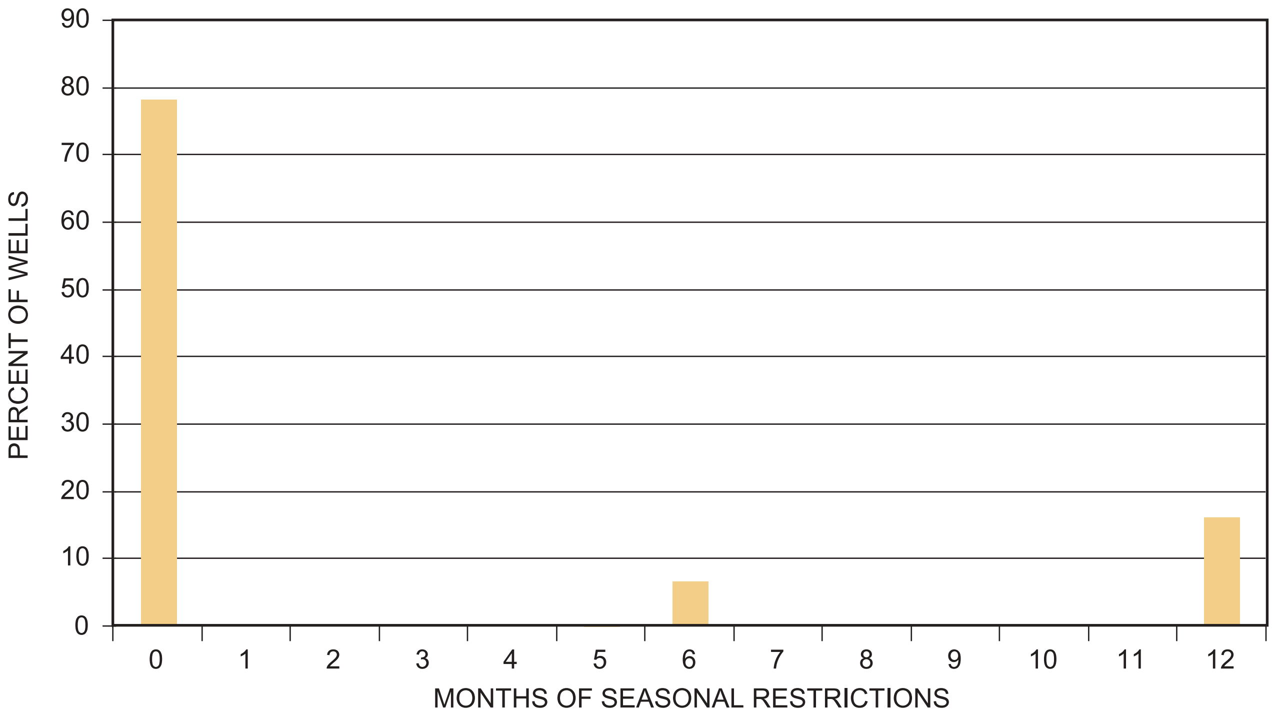
	0-10k	10-20k	20-30k	30-40k	50-100k	40-50k	100k +	All
0	43.4%							43.4%
3	6.9%						49.5%	56.4%
6								
9								
12								
18								
24								
36+							0.2%	0.2%
All	50.3%						49.7%	100.0%

Unavailable Resources on Fee Lands		
EPCA (Fed only)	**NPC Addition**	**Total**
0.0%	15.8%*	15.8%

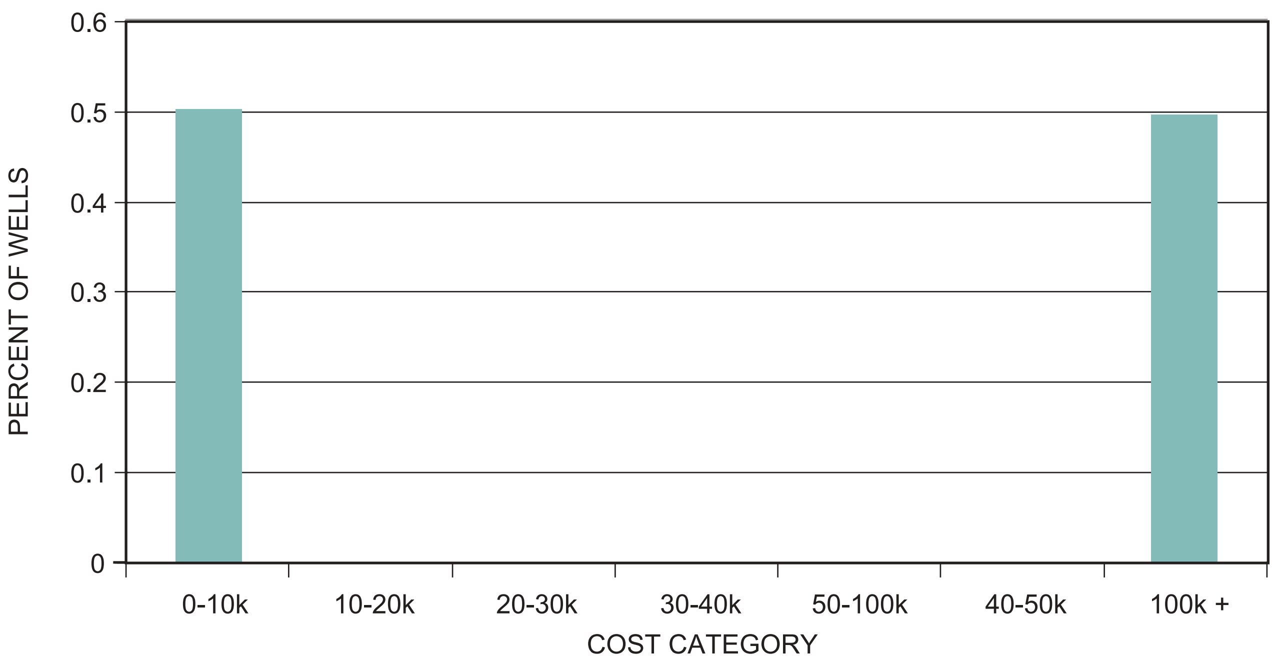
H.C. % =	41.8%*

* NPC Addition is all 9- to 12-month seasonal restrictions.

Uinta-Piceance Basin (All) – Development Wells: Fee



Percent of Wells By Months of Seasonal Restrictions: Uinta-Piceance (All)



Percent of Wells By Cost Category: Uinta-Piceance (All)

CHAPTER 7

ARCTIC DEVELOPMENTS

The North American Arctic regions in Northwestern Canada and Alaska contain significant gas resources that can help meet future North American gas demand. Discovered resources include about 35 trillion cubic feet (TCF) on the North Slope of Alaska and 9 TCF in the Mackenzie-Beaufort basin.

These gas resources are far from any existing pipeline infrastructure and are located in an arctic environment, so significant investment will be required to bring these resources to market. The key hurdles associated with commercializing these resources are costs, permitting, Alaska state fiscal issues, and market risks. Even though these resources were discovered over 30 years ago, these hurdles have prevented the development of commercially viable projects.

Industry is continuing to work on new technologies to reduce capital costs, and the governments of the United States, Alaska, and Canada recognize the significant risks of such large-scale projects and are working to put frameworks in place to address some of the hurdles. These efforts are to be encouraged because the supply/demand picture supports the need for additional supplies.

This NPC study assumes that appropriate government frameworks will be achieved in a timely manner and that the economic and political climate will support Arctic gas projects. Consequently, it is assumed that these projects will come on line at what is considered the earliest feasible dates: 2009 for a Mackenzie Gas Project and 2013 for an Alaska gas pipeline. The volumes assumed to be transported by these projects are shown in Figure S7-1.

If these projects are delayed, there could be adverse consequences for consumers in the form of reduced gas supplies or higher energy prices. It is also recognized that these projects may not be commercially viable if projected returns are inadequate to justify the large investments needed. This is particularly true if additional government requirements or burdens increase project costs and impede the ability of these large projects to compete with alternatives.

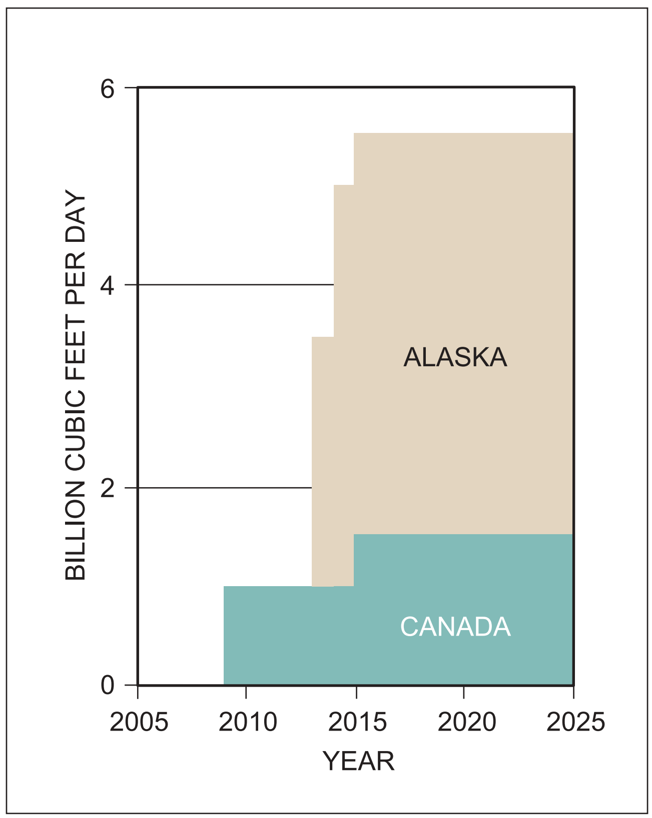


Figure S7-1. Arctic Production Profile

I. Canadian Arctic Gas Background

A. Resource

Table S7-1 summarizes the NPC study team assumptions on the Discovered and Undiscovered Potential resource available from the Canadian Arctic; the data is based on information from the Canadian Gas Potential Committee. This committee is a volunteer group of industry and government geoscientists that uses geological judgment, extensive peer reviews, and statistical analysis to make its assessments of future natural gas reserves in Canada.

Active drilling in the Canadian Arctic began in the late 1960s after interest was sparked by the huge oil and gas discovery made in a similar geological play at Prudhoe Bay in 1967. A number of onshore gas discoveries were made in the early 1970s in the Mackenzie-Beaufort Regions and in the more remote Arctic Islands region. That region is located approximately 1,000 miles northeast of the Mackenzie Delta in a harsh arctic environment. Figure S7-2 shows the relative location of the Mackenzie-Beaufort and the Arctic Islands.

B. Attempts to Commercialize

In the early 1970s, once gas was discovered in the Mackenzie Delta, several proposals were advanced to build a pipeline to transport that gas to markets in Canada and the United States. About the same time, there were other proposals to build a pipeline to transport Prudhoe Bay gas to those same markets. Proposals for transporting Mackenzie Delta gas were for a direct route along the Mackenzie River.

In the mid-1970s, the U.S. and Canadian governments worked cooperatively in the interest of expediting the selection and construction of a pipeline to transport Arctic gas from Alaska and Canada to North American markets. However, in 1977 Canada's Berger Commission recommended a 10-year moratorium on construction of a pipeline along the Mackenzie River so that the land claims of aboriginal groups could be settled and social and environmental concerns could be addressed. The U.S. and Canadian governments subsequently approved a route that followed the Alaska Highway and designated it as the Alaska Natural Gas Transportation System (ANGTS). To address the Canadian government's concern that Canadian gas might be stranded, the U.S. and Canadian governments proposed future construction of the so-called "Dempster Lateral" for moving Mackenzie Delta gas into ANGTS. Figure S7-3 shows the ANGTS and Dempster Lateral routes. In spite of efforts by pipeline companies and producers in the late 1970s and early 1980s, the ANGTS and Dempster Lateral proved not to be economic and were not built.

Region	Discovered	Undiscovered Potential
Mackenzie Corridor	0.7	4.6
Mackenzie/ Beaufort Sea	8.8	21.2
Arctic Islands	16.4	9.4
Total	**25.9**	**35.2**

Source: Canadian Gas Potential Committee, 2001.

Table S7-1. Canadian Arctic Gas Resource (Trillion Cubic Feet)

With the passage of time, most aboriginal land claims in the vicinity of the Mackenzie River were settled. In the late 1980s and early 1990s the major owners of the onshore Mackenzie Delta Gas (Imperial Oil, Shell Canada, Gulf Canada) revisited the possibility of a pipeline along the Mackenzie River and secured licenses from the Canadian National Energy Board to export gas to the United States. However, the availability of lower-cost supplies at that time meant that the major capital expenditures required to construct the pipeline could not be commercially justified.

C. Current Status of Project Development

The Mackenzie Delta Producers Group (Imperial Oil, ConocoPhillips Canada, Shell Canada Limited, and ExxonMobil Canada) and the Mackenzie Valley Aboriginal Pipeline Corporation (MVAPC) are currently working to develop a Mackenzie Gas Project, including a Mackenzie Valley pipeline. The pipeline would transport onshore natural gas resources from the Taglu, Parsons Lake, and Niglintgak gas fields, and would be accessible to other natural gas discoveries in the Mackenzie Delta and Mackenzie Valley regions. The gas would be transported through the Mackenzie Valley to existing gas pipelines in northwestern Alberta for further transportation to market.

Figure S7-4 shows a schematic view of the proposed Mackenzie Gas Project. This project is currently in the project definition phase. This phase involves technical and environmental consultation as well as commercial

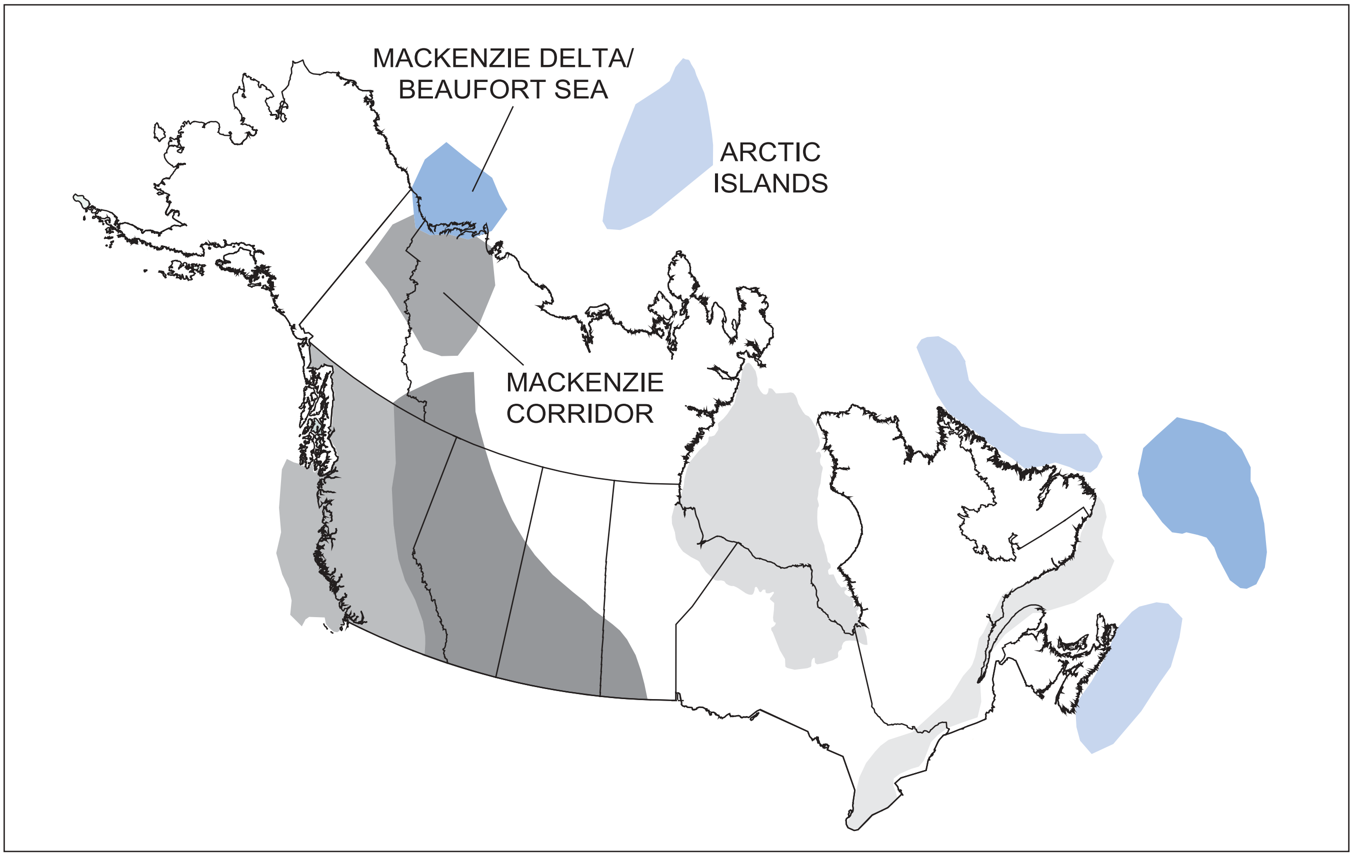


Figure S7-2. Locations of Canadian Arctic Regions

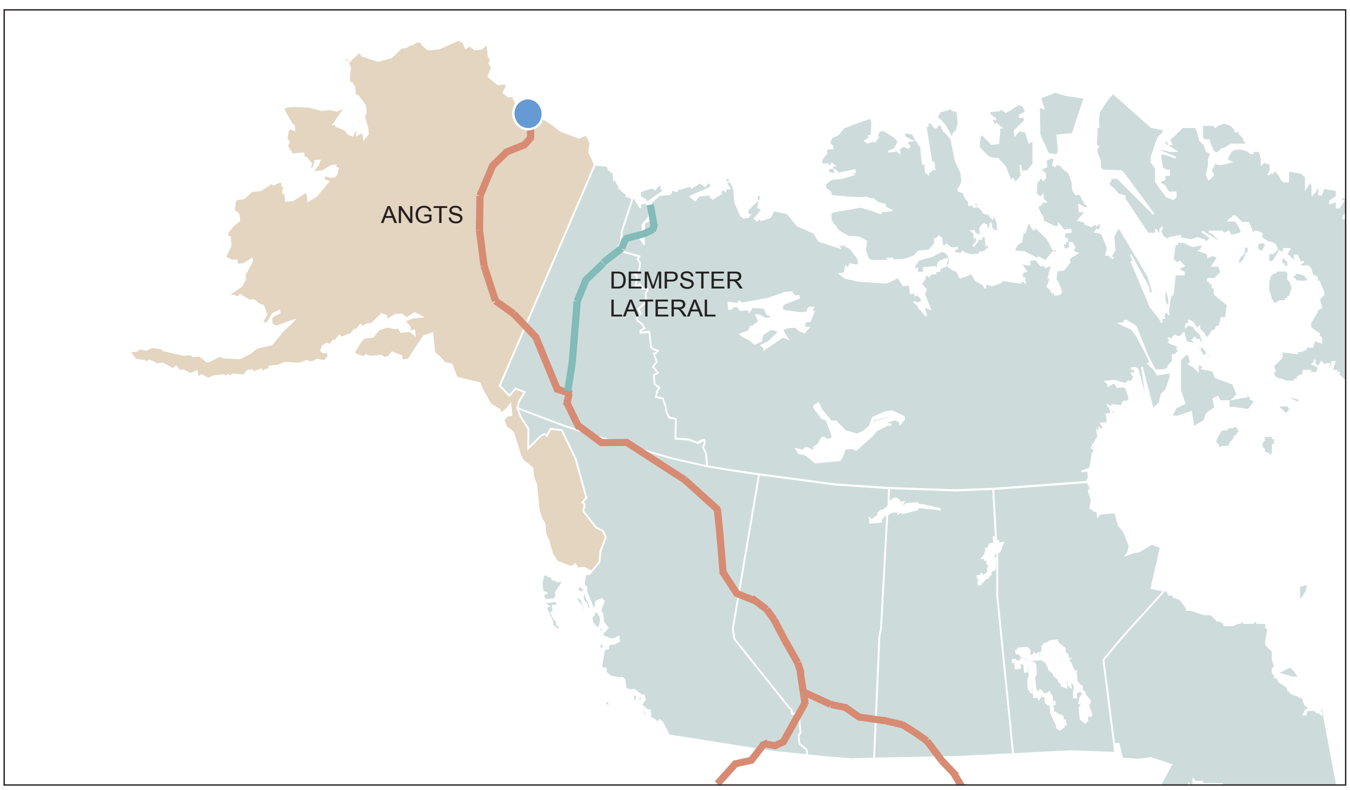


Figure S7-3. ANGTS and Dempster Lateral Routes

Figure S7-4. Proposed Mackenzie Gas Project

work required to prepare, file and support regulatory applications for field, gas-gathering and pipeline facilities. Regulatory applications are expected to be filed in 2004 supporting start-up of the Mackenzie Gas Project in 2009.

A study commissioned by the Government of the Northwest Territories (GNWT) and TransCanada PipeLines Limited and published by Wright Mansell Research Ltd. in May 2002 indicates that direct investments, expressed in 2002 dollars, may total 7.6 billion Canadian dollars. This estimate consists of $4.3 billion for field development and $3.3 billion for pipeline construction.[1]

D. Risks and Hurdles

There are significant risks and hurdles associated with commercializing Canadian Arctic gas; the fact

1 *An Evaluation of the Economic Impacts Associated with the Mackenzie Valley Gas Pipeline and Mackenzie Delta Gas Development*, published May 13, 2002, and available at the GNWT website: www.gov.nt.ca.

that the gas has yet to be commercialized in spite of having been discovered over 30 years ago is testimony to that fact. Among these are permitting, cost, and market outlook.

1. Permitting

Many permits will be required for both the field and pipeline facilities; exactly how many is not known because the precise regulatory framework is still evolving. The indigenous peoples of Northern Canada (First Nations) hold certain rights under agreements with the Canadian federal government. The First Nations have generally expressed support for responsible resource developments that generate meaningful opportunities without compromising First Nations' social and economic well being and that respect the land, wildlife and its habitat. As a result of the settlement of land claims in areas through which a Mackenzie Valley pipeline would pass, many new agencies have been established. Sponsored by the government of Canada, the various agencies have published a cooperation plan that describes how such a review process is to be coordinated. However, the process is untested and has the potential to delay project execution and construction. In addition, permit stipulations could add costs that could undermine commercial viability.

2. Cost

Due to the remote arctic location of these resources, the investment needed to build the infrastructure for developing the resources and transporting the gas to market is considerable. This presents two issues: (1) large-scale investments in pipelines imply high fixed transportation costs, which reduce the value of the gas to the owners; and (2) large-scale investments entail the risk of significant cost overruns that could adversely affect a project's commercial viability.

3. Market

It is necessary to have a market outlook over a 20-30 year time period that is sufficiently encouraging to justify the large investments required.

II. Alaska Arctic Gas Background

A. Resource

Oil and gas have been produced on the Alaska North Slope since the late 1970s. In the absence of a market, most of the gas has been reinjected to enhance the recovery of oil. The size of the discovered gas resource is well understood given the extensive development and long production history in the Prudhoe Bay Field.

Table S7-2 summarizes the discovered resource available from the Alaska Arctic. All discovered resource data except for Point Thomson is taken from the January 2001 MMS Report entitled *Prospects for Development of Alaska Natural Gas: A Review*. The Point Thomson data is from ExxonMobil as reported in the June 15, 2002 issue of the Alaska Oil & Gas Reporter. The ExxonMobil data for Point Thomson (8 TCF) is higher than that reflected in the MMS Report (5 TCF).

Figure S7-5 contains a map showing the major North Slope fields. Most of the discovered resource is contained in the massive Prudhoe Bay field.

1. Prudhoe Bay

The Prudhoe Bay field is the largest oil field in North America and the 18th largest field ever discovered worldwide. Of the 25 billion barrels of original oil in place, more than 13 billion barrels is expected to be recovered with current technology. More than 10 billion barrels have already been produced. The field also contains an estimated 23 trillion cubic feet of natural gas that could be recovered from an overlying gas cap and from gas in solution with the oil.

The Prudhoe Bay field is owned by ExxonMobil and ConocoPhillips, each with approximately 36%, BP at 26%, and others with a combined 1%. The State of Alaska holds a 12.5% royalty interest. The field is operated by BP. Together the major owners have invested

Resource	TCF
North Slope	
Prudhoe Bay	23
Point Thomson	8
Other North Slope	4
Total	**35**
Other	
Burger (Chuckchi Sea)	2-10

Table S7-2. Alaska Arctic Gas Discovered Resource

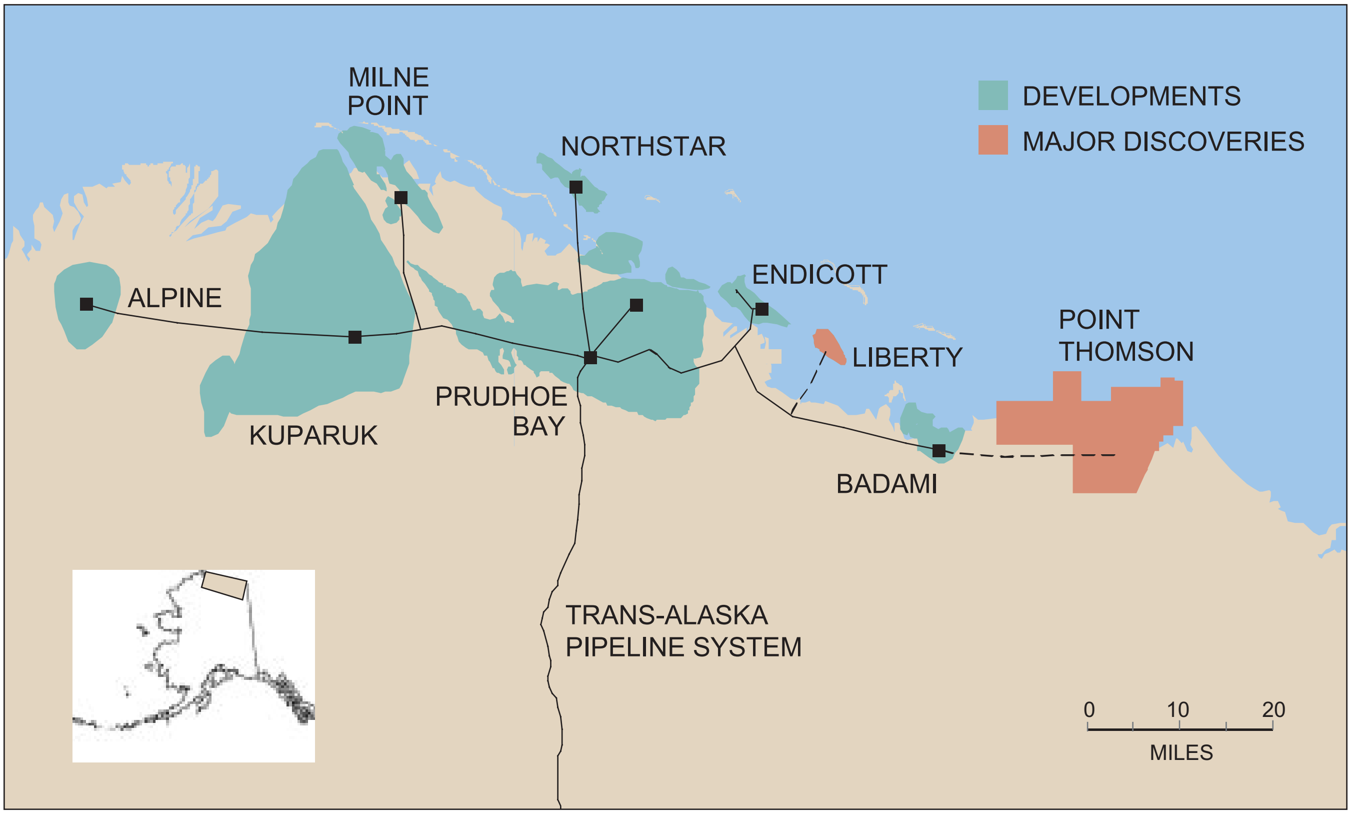


Figure S7-5. Major Alaska North Slope Fields

more than $25 billion in developing these Prudhoe Bay oil and gas resources not counting the Trans-Alaska Pipeline System which cost another $8 billion.

The Prudhoe Bay field came on stream in 1977; at peak production the field's daily production was more than 1.6 million barrels of oil and natural gas liquids. Current liquids production is around 600,000 barrels per day. Some 8 billion cubic feet per day of produced natural gas is currently processed through the Central Gas Facility, which is the world's largest gas processing facility. Most of the natural gas is re-injected to maintain reservoir pressure, thereby improving oil recovery. Natural gas liquids are extracted from the gas, blended with crude and then exported via the Trans Alaska Pipeline System. Other dispositions of this gas are described below.

Six oil separation facilities in the Prudhoe Bay field (Figure S7-6) are designed to process up to two million barrels of oil and gas liquids per day. Each facility separates gas and water from the oil. The gas from the separation facilities is routed to the Central Gas Facility and the Central Compression Plant (Figure S7-7) located in the northern part of the Prudhoe Bay field.

About 80,000 barrels per day of natural gas liquids are extracted by a refrigeration process and then either shipped down the Trans-Alaska Pipeline with the Alaskan crude oil or transported to the Kuparuk and Milne Point fields to be used for enhanced oil recovery. A portion of the natural gas is used to produce a miscible gas injectant, which is then used for enhanced oil recovery. The remaining gas is compressed for re-injection into the gas cap of the reservoir to maintain pressure. A portion of the processed gas is used to

Figure S7-6. Flow Station 1

Figure S7-7. Central Compression Plant

supply field fuel. In addition, water is re-injected into the formation to help maintain reservoir pressure and enhance recovery. Also, additional water from the Beaufort Sea is processed at the Seawater Treatment Plant and injected into the reservoir as part of a field-wide water flood program to maintain pressure and sweep oil from the reservoir rock.

2. Point Thomson

The large, high-pressure Point Thomson gas condensate field was discovered in 1977; it is estimated to contain some 8 trillion cubic feet of recoverable natural gas, along with recoverable condensate. The Point Thomson reservoir is located about 60 miles east of Prudhoe Bay. The nearest facility is located at the Badami Field, about 22 miles west of the Point Thomson Unit (PTU). Nineteen exploration wells have been drilled around the Point Thomson area. Of these wells, 14 have penetrated the Thomson sand. A number of 3D seismic surveys have been conducted and acquired covering most of the unit acreage. ExxonMobil, with a 36% working interest, is the Point Thomson Unit operator. The other major owners include BP (32%), ChevronTexaco (25%) and ConocoPhillips (5%). There are also 26 minor owners, with a total working interest of about 2%.

The Point Thomson Field is currently undeveloped. The Point Thomson owners are currently working to put in place a development plan that will recover condensate for transportation through the Trans-Alaska Pipeline System (TAPS). The natural gas from Point Thomson would be injected to enhance liquids recovery. That gas would subsequently be recovered and made available for sales once a commercially viable Alaska gas pipeline is constructed.

3. Other Discovered

In addition to the 23 TCF at Prudhoe Bay and 8 TCF at Point Thomson there is also 4 TCF of discovered resource in other North Slope fields including Alpine, Milne Point, Kuparuk, Northstar, Point McIntyre, Lisburne and Endicott. The estimated 2-10 TCF of discovered resource at the Burger Field in the Chukchi Sea could remain uneconomic for many years because it lies in perennially ice-bound waters 160 feet deep, 70 miles from shore, and 360 miles west of Prudhoe Bay.

4. Undiscovered Potential

The Undiscovered Potential depicted in Figure S7-8 was developed from USGS and MMS data and is described further in the Resource Section of this report.

In their 2002 study discussed later in this report, the Alaska gas producers concluded that development of resources beyond those currently discovered will be required to maintain a large-diameter gas export pipeline at full capacity for the anticipated life of the project. Therefore, access to these new resources will be an important factor in successful commercialization of Alaska gas. The undiscovered potential for the Alaska Arctic in this NPC study totals 213 TCF, consisting of 116 TCF onshore (including 44 TCF of non-conventional coal-bed gas) and 97 TCF offshore. Some of this prospective acreage is currently available to industry, but other areas are not. Government policies to access gas-prone acreage in Alaska will play a key role in ensuring that the gas resources continue to be produced from Alaska well into the future.

B. Attempts to Commercialize

Alaska gas development projects have been proposed, planned and studied since oil and gas was first discovered on the North Slope in 1967. The options have included various pipeline, liquefied natural gas (LNG), and gas to liquids (GTL) concepts.

1. Pipeline

a. 1970s Pipeline Development

The initial impetus for developing Alaska's natural gas took place during the 1970s, amid concerns about natural gas shortages in the United States that resulted from wellhead price regulation. Energy producers identified the Arctic gas resources on the North Slope of Alaska as a possible solution to this shortage. This led several companies in the mid-1970s to propose

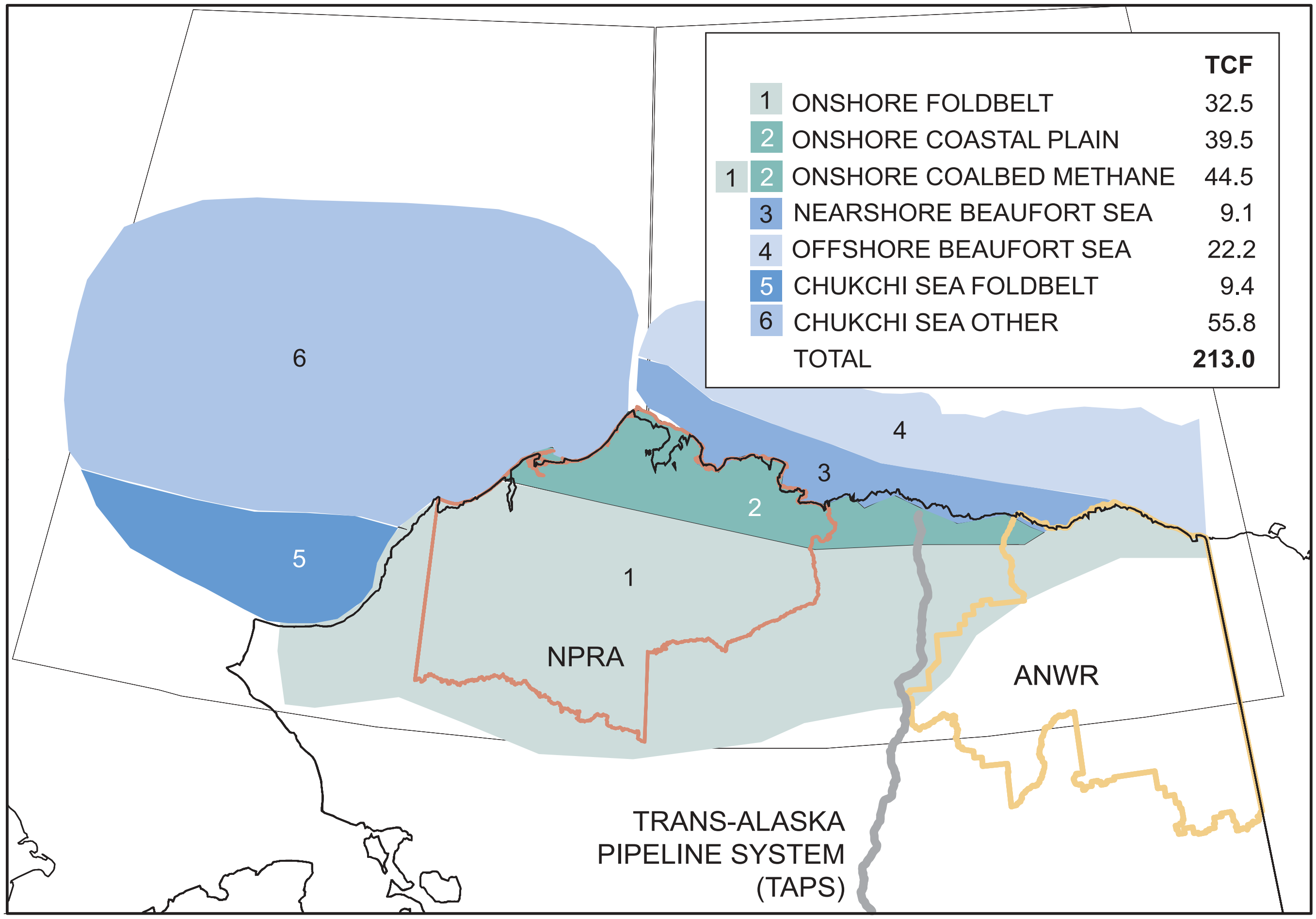


Figure S7-8. Undiscovered Resource Potential – North Alaska Super-Plays

systems to transport natural gas resources from Alaska and Canada to the lower-48 states.

b. Competing Proposals

In 1976, there were three competing proposals to develop Alaska gas before the Federal Power Commission, the predecessor to the Federal Energy Regulatory Commission (FERC). The three proposals were as follows:

- Alaska Arctic Gas Pipeline Company and Canadian Arctic Gas Pipeline Company (Arctic Gas) proposed an overland pipeline from the North Slope to the continental U.S. The route would have crossed the Arctic National Wildlife Refuge (ANWR) in the United States and followed the Mackenzie River valley in Canada. The pipeline was designed to carry both Alaska and Mackenzie Delta gas to U.S. markets in the mid-west and west coast.

- El Paso Natural Gas Company proposed an "all-American" gas pipeline from Prudhoe Bay to the Alaska tidewater region, where it was to be liquefied and delivered by LNG tankers to California.

- Alcan (a wholly owned subsidiary of Northwest Pipeline), and Foothills Pipeline (a Canadian firm) proposed a pipeline south from Prudhoe Bay, following the TAPS route to Fairbanks, then southeast along the route of the Alaska Highway into Southern Alberta. From Alberta, the gas was to follow two pipeline routes into the mid-west and west coast.

c. Alaska Natural Gas Transportation Act of 1976

On October 22, 1976, recognizing the shortages of natural gas, the large resources of natural gas in Alaska, the benefits resulting from the expeditious construction of a transportation system for that gas, and the potential for delays inherent in the normal regulatory approach to a project of this magnitude, Congress passed the Alaska Natural Gas Transportation Act of 1976 (ANGTA) to expedite the selection, construction, and initial operation of an Alaska natural gas transportation system. Designed to draw upon all relevant governmental, public and private expertise in reaching a presidential and congressional decision on an Alaska natural gas transportation system, the statute established a unique process for reaching an expedited decision with limited judicial review.

On May 2, 1977, shortly after the passage of ANGTA, the FPC recommended to the President an overland route through Canada but divided 2-2 on the choice between Alcan's southern route and Arctic Gas's northern route. On July 4th, 1977, Canada's National Energy Board (NEB) stated it was prepared to certify Alcan conditioned upon several modifications of the Alcan system recommended by the FPC.

d. U.S. and Canadian Government Selection of the ANGTS

In late 1977, after extensive public hearings in Canada and the United States, the Alcan route proposed by Northwest and Foothills was chosen. President Carter approved this selection and designated it as the Alaska Natural Gas Transmission System (ANGTS). The Presidential Decision was closely coordinated with the government of Canada and included an agreement between the United States and Canada on principles applicable to a northern natural gas pipeline, adopted September 20, 1977 ("the U.S.-Canada Agreement"). This included agreements on the construction and operation of ANGTS, including the designation of the builders and operators and agreements as to tariffs and cost allocation.

Integral to the Canadian government endorsement was a decision by the National Energy Board of Canada to support a recommendation by Justice Thomas Berger following the Mackenzie Valley Pipeline Inquiry. From 1974 to 1977, Justice Berger had served as the commissioner of the Mackenzie Valley Pipeline Inquiry. His report, *Northern Frontier, Northern Homeland* (1977), recommended a 10-year moratorium on the building of a pipeline through the Mackenzie Delta and the Mackenzie Valley so that native land claims could be settled. This resulted in the NEB favoring the Northwest Energy proposal over the Arctic Gas proposal. That same year, Canada and the United States signed a treaty guaranteeing nondiscriminatory treatment of Alaska gas shipped through Canada.

A primary concern of Canada during this time was to ensure the connection of Northern Canadian gas supplies to the U.S. market. This concern was amplified by the Berger report's recommendation of a 10-year moratorium on development in the Mackenzie Valley. Consequently, Canada entered into the Dempster Link Agreement with Foothills Pipelines to file an application to construct a lateral along the Dempster Highway connecting the Mackenzie Delta to the ANGTS. The Dempster Lateral would provide a means for Canada to develop Mackenzie Delta reserves during the moratorium. However, the agreement expired in April 2000 without ANGTS or the lateral being constructed. Land claims in the Mackenzie Valley are now mostly resolved and a Mackenzie Valley pipeline is now being pursued as a means to transport Mackenzie Delta gas to market.

In 1978, The Canadian Parliament enacted the Northern Pipeline Act, the Canadian counterpart to ANGTA, which certified the construction of the pipeline in Canada and established the Northern Pipeline Agency as the principal regulatory authority to oversee the planning and construction of the Canadian portion of the pipeline.

In 1981, President Reagan submitted and Congress approved a waiver-of-laws package to enhance the project's prospects of obtaining private financing. The waivers allowed equity participation by North Slope producers, included a gas conditioning plant as part of the pipeline system and permitted the recovery of costs from consumers before completion of the system.

e. Gas Deregulation and Falling Prices

As the ANGTS project definition advanced, fundamental changes were sweeping the U.S. natural gas markets. By the mid-1980s gas deregulation was in full swing resulting in a surplus of natural gas, which caused gas prices to plummet. The high-cost ANGTS project was not commercially viable in that environment, and could not be financed.

Ultimately, the ANGTS sponsors spent some $800 million on engineering, socio-economic and environmental studies. While some southern sections of the pipeline, comprising some 1,512 miles of pipelines from Alberta to Iowa and Oregon, were constructed, these sections do not transport Arctic gas. Rather, they carry Canadian gas from Alberta to customers in the U.S. Midwest and California. Alaska and Mackenzie Delta gas resources remain stranded.

f. Alaska Gas Producers' Pipeline Study

In late 2000 with increasing evidence of a need for additional gas supplies and support for developing Alaska's gas, BP, ConocoPhillips, and ExxonMobil jointly committed $125 million to assess the feasibility of constructing a pipeline to the lower-48 states. The results of this study are summarized in Section C, "Current Status of Project Development."

g. President Bush's National Energy Policy

In May 2001, the U.S. Administration identified a growing need to reduce U.S. dependence on foreign energy. One feature of the President's National Energy Policy was to re-energize interest in the Alaska gas resource and recommend that an interagency task force work closely with Canada, the State of Alaska, and all other interested parties to expedite the construction of a pipeline to deliver natural gas to the lower-48 states. Many of the President's recommendations, including provisions that would expedite the construction of an Alaska gas pipeline, are part of an energy bill that is currently being debated by Congress.

2. LNG

In 1983, former Alaska Governors Wally Hickel and William Egan formed Yukon Pacific Corporation (YPC) and proposed to develop Alaska's gas resources via a Trans-Alaska Gas Pipeline parallel to the TAPS oil pipeline, with a liquefaction plant near Valdez. Liquefied natural gas would be sold to buyers in the Far East. YPC secured a number of permits and rights-of-way for its proposed project.

As U.S. gas prices declined and the prospects for the ANGTS pipeline project dwindled, ARCO Alaska, Yukon Pacific and 15 Japanese companies sponsored a preliminary feasibility study that looked at an LNG export option to Asia. The study, completed in 1987, concluded that the timing for an LNG option was not right.

In 1992, with the cost estimate of the ANGTS option increasing beyond $20 billion, Alaska's major North Slope producers (ARCO, BP, and Exxon) initiated a technical study of the Alaska LNG export option.

The study concluded that Alaska LNG was uneconomic given the market and commercial risks involved. Most significantly, unlike the vast majority of other LNG projects, it would require a major pipeline to bring the gas to tidewater, rendering the project uncompetitive with LNG supplied from tidewater gas resources in other parts of the world. Additionally, the LNG project would need to be sized to deliver 14 millions tons of LNG per year to achieve economies of scale. The study concluded that it would be difficult for the Asian LNG market to absorb such a volume. To place the Alaska project volumes in the market over a five-year ramp-up period would require the project to capture all the projected market growth in Japan and South Korea over those five years. Furthermore, a study conducted by a consultant hired by the State of Alaska (*Suggestions For New Terms For The Alaska North Slope LNG Project* by Dr. A. Pedro H. van Meurs, February 12, 1997) concluded "the Alaska fiscal system is not optimal for an LNG project. The rate of return to the investors is less than it needs to be." In combination, these factors meant that LNG prices in the Far East would be too low to make the project viable.

In 1997 ARCO, in partnership with Foothills Pipeline, Phillips, Yukon Pacific (currently a subsidiary of the CSX Corporation), Marubeni and later BP, built upon the North Slope producers' earlier work to develop a smaller, phased project design to reduce the market entry and other commercial risks. This concept was also determined to be uneconomic.

While industry continues to view Alaska LNG as uncompetitive, some interest outside industry remains in investigating transportation to the U.S. West Coast or to Southeast Asia via LNG. The State of Alaska may be exploring project feasibility on its own as a result of a ballot measure passed by voters in 2002. The conclusions of the 1992 and 1997 LNG studies are expected to remain valid and the LNG option for commercializing Alaska North Slope gas is unlikely to be commercially viable.

3. Gas to Liquids

A number of companies including BP, ConocoPhillips, and ExxonMobil have worked on developing improvements to gas-to-liquids (GTL) technology that chemically converts natural gas into high-quality conventional liquid products. If this technology were to be applied on the North Slope of Alaska, the existing TAPS oil pipeline could be modified to transport the resulting liquid products to market. However, this technology is currently not economic in a high-cost arctic environment.

C. Current Status of Project Development

1. Producer Study Overview

The major North Slope gas producers – BP, ConocoPhillips, and ExxonMobil – completed a comprehensive study during 2001-2002 to assess the feasibility of delivering Alaska gas to lower-48 markets. This study assessed the cost, technology, regulatory and environmental issues associated with the project. One-hundred-twenty-five million dollars was spent on this study, which involved 110 owner company representatives and over one million staff-hours (including contractors).

The study considered a pipeline system designed to transport approximately 4.5 billion cubic feet per day (BCF/D) and expandable to 5.6 BCF/D through intermediate compression. Approximately 0.5 BCF/D would be extracted for fuel use and for natural gas liquid (NGL) extraction resulting in approximately 4 BCF/D for delivery to market. The major system components would include a gas treatment plant (GTP), an Alaska-to-Alberta pipeline system, an NGL extraction plant, and an Alberta-to-lower-48 pipeline system. Figure S7-9 shows an overall schematic diagram of the system.

The GTP, to be located on the North Slope, would remove CO_2 (to 1.5 mole %) and H_2S (to 4 ppm), chill (to 30°F) and compress the gas (to 2,500 psig) for introduction into the Alaska-to-Alberta gas pipeline system. This large processing facility would very probably cost more than the combined costs of the recent North Slope Alpine, Badami, Northstar, and the Prudhoe Bay Field MIX (Miscible Injection Expansion) projects.

The Alaska-to-Alberta pipeline component would take treated gas from the GTP and transport it to Alberta. The producers studied two different routes to accomplish this, both of which would consist of a 52-inch, buried, thermally controlled pipeline, designed for a maximum operating pressure of 2,500 psig. A "Southern Route" option would be 2,141 miles in length generally following the TAPS right-of-way south from the North Slope to Delta Junction, before following the Alaska Highway system into the gas hub in Alberta, Canada. A "Northern Route" option would be 1,802 miles in length. It was assumed that this route would go offshore North of ANWR and Ivvavik National Park in Canada and then generally follow the Mackenzie River valley into Alberta.

The NGL plant would process Alaska gas to the delivery specifications of distributors.

The study team recognized the potential need for additional export capacity to move Alaska gas from Alberta to its ultimate market destination. As one option, the team studied a "new-build" pipeline system from Alberta to Chicago. More efficient alternatives may ultimately be developed to move Alaska gas out of Alberta to consumers, utilizing existing pipeline systems. These alternatives include the use of existing pipeline capacity made available by declining availability of gas from existing sources, or expansion of existing pipeline systems. Ultimately, performance of existing Canadian supplies and prevailing market conditions will determine how Alaska gas is transported out of Alberta. The new-build system would originate at the point of termination of the Alaska pipeline near Vegreville, Alberta. From this location, the new line would be routed generally parallel to the existing Alliance Pipeline right-of-way, continuing 1,500 miles into the Chicago gas hub. This 52-inch pipeline system would operate at a maximum pressure of 2,000 psig.

2. Mackenzie Delta Synergies

There are several potential synergies between Mackenzie Delta and Alaska gas development depending on the routing for Alaska gas and timing. Areas of synergy include trained workforce availability, application of lessons learned from field construction, establishment of the required Canadian regulatory process, and perhaps even the sharing of a common right-of-way or pipeline. While the value of each of these areas of synergy has not been separately quantified, they are expected to be significant. In contrast, simultaneous construction of separate routes presents substantial logistical challenges in resource availability (e.g., labor and materials) that could result in substantial cost increases.

3. Gas Supply Assumptions and Expansion Opportunities

The initial design capacity of an Alaska gas pipeline would be established through an "open season" process whereby potential shippers would make firm transportation commitments that would encourage construction and support the financing of the pipeline system. For the purposes of their study, the producers assumed that the pipeline would initially transport 4.5 BCF/D of gas from known discoveries. However, since

Figure S7-9. Alaska Gas Pipeline System those fields do not contain sufficient resource to keep the pipeline full for an entire 30-year project life, the producers assumed that an additional 16 TCF of "yet-to-find" gas will be discovered and economically developed, and transported through the system.

In the event that sufficient additional gas is discovered and can be economically developed, the pipeline system can be expanded. The producer study determined that the number of compressor stations could be doubled, increasing pipeline capacity by 1 BCF/D at a toll that would be comparable to the base pipeline.

4. Technical Challenges

Technical challenges exist for either pipeline route. For the northern route, the issues to be resolved are ice scour, whaling interaction, and the open-water window; for the southern route, they are seismic activity, steep terrain, and proximity to population centers. While both routes represent significant challenges of logistics and scale, the producers concluded that these challenges are within the capability of current technology. Resolution of these technical issues would be completed prior to submission of regulatory applications.

5. Producer Study Conclusions

The producers concluded that both the northern and southern routes were within current technical capability. The producers also concluded that the macroeconomic development from an Alaska gas pipeline is significant. Total government direct revenues could be over $100 billion. In addition to these direct tax and royalty revenues, there would be significant economic stimulus through creation of thousands of jobs. However, the producers concluded that an Alaska gas pipeline project via any route was currently not commercially viable. They determined that project risks outweighed rewards, that additional engineering work was not justified at that time, and that future activity must match progress with governments and commercial viability.

The producers also concluded that governments could play a key role in reducing project cost and schedule risk. Mitigation of these risks could be achieved through enactment of U.S. federal regulatory enabling legislation to provide efficiency and clarity in the regulatory process for the U.S. portion of the pipeline, clarity with the NEB/First Nations regulatory process, and fiscal certainty for the project with the State of Alaska.

The three major North Slope producers continue to work on potential cost reduction concepts with governments in order to establish appropriate frameworks for addressing these risks. These items are discussed further in the next section, "Risks and Hurdles," and in the Recommendations section at the end of this chapter.

D. Risks and Hurdles

Four key risk areas must be addressed before an Alaska gas pipeline will attract investment capital from the private sector. The four risk areas are cost, permitting, state fiscal risk, and market risk. In addition the U.S. government is debating a fiscal package related to the Alaska gas pipeline project.

1. Cost

An Alaska gas pipeline project will be the largest-ever privately funded development project. Both the large investment required for the project and the prospect of cost overruns represent significant project risks. While a number of pipeline companies have expressed interest in participating in the construction and ownership of an Alaska gas pipeline, they are not likely to be able to assume the actual financial and market risks inherent in the project. For example, pipeline owners will expect shippers (likely to be the producers of the gas) to commit to firm transportation contracts. Under those contracts the shippers will be obligated to pay tolls that will be based on the cost of building the pipeline. Pipeline owners may agree to bear some cost overrun risk, but most of that risk will be passed to the shippers (producers) via higher tolls.

A reduction in capital cost would directly affect the commercial viability of the project. To this end, the Alaska natural gas producers are working to advance various technological options for reducing the capital cost of the pipeline.

Some of the major cost uncertainties include material costs, labor costs, and construction productivity (particularly during winter construction). In addition, government actions in the form of mandates (e.g., sourcing of materials, project labor agreements, route) or permit stipulations could have the effect of increasing project costs.

The following potential opportunities have been identified.

- Use of high-strength steel, which reduces the amount of steel required and helps simplify some of the construction logistics.
- Reviewing alternate processing technologies for removal of CO_2 in the Gas Treatment Plant.
- Welding improvements to reduce the number of welding stations required.
- Increased main-line valve spacing
- Design optimization to improve hydraulic design and cooling requirement.
- Route optimization to reduce pipeline length.
- Infrastructure upgrades, such as improvements to roads, bridges, and port facilities that could be addressed by governments. A study completed in 2003 identified 270 million dollars of potential improvements in Alaska. A similar analysis may be completed for Canada.

2. Permitting

Many permits or approvals will be required from the U.S., state, local, Canadian, territorial, and provincial governments. In addition agreements with First Nations will be required for an Alaska gas pipeline project. The permitting process and potential legal challenges could cause significant delays. In addition, permit stipulations could add costs that might reduce a project's commercially viability.

Historically, the time required to obtain permits for gas pipeline projects has varied widely. In some cases, it has taken 4 or 5 years to secure the necessary permits for projects that were not as large or complex as the Alaska gas pipeline and which did not involve as many jurisdictions.

The risks associated with securing U.S. permits can be reduced through enactment of the U.S. federal enabling legislation that was jointly proposed in 2001-02 and supported by the major North Slope producers, the State of Alaska, and potential explorers and pipeline companies. The legislation was included as part of the Senate Energy Bill in 2002, although it was not passed into law during the 2002 Congressional session. The proposed enabling legislation is now part of the energy bill being considered by Congress during the 2003 session. Key features of the legislation include:

- Requiring FERC to expedite the issuance of a certificate to construct the pipeline once certain requirements under the Natural Gas Act have been met. Certificate are to be issued within 20 months of a completed application;
- Designating FERC as the lead agency for the National Environmental Policy Act or Environmental Impact Statement process;
- Creating a Federal Coordinator within the executive branch to coordinate the activities of the participating federal agencies;
- Requiring that a single environmental impact statement be utilized by all U.S. agencies;
- Addressing limitations on the timing of potential legal challenges.

The energy bill being debated in Congress includes a mandate that would prohibit the issuance of federal permits for a northern route. The State of Alaska has also mandated a southern route. The U.S. Administration, however, has stated its belief that market forces should select the route.

As illustrated in Figure S7-10, a significant portion of either pipeline route will be in Canada. Approvals will be required from the Canadian National Energy Board, various provinces and territories, and agreements with First Nations. The indigenous peoples of northern Canada (First Nations) hold certain rights under agreements with the government of Canada. The First Nations have generally expressed support for responsible resource development which generates meaningful opportunities without compromising First Nations' social and economic well-being and which respects the land, wildlife and its habitat.

As the roles of various parties are defined, the specifics of the regulatory process in Canada continues to evolve. The development and definition of this process will be critical in ensuring efficient and timely regulatory approvals.

While new legislation is not required in Canada, additional clarity and efficiency of the Canadian

Figure S7-10. Alaska-Canada Section of Alaska Gas Pipeline System

regulatory process is essential for ensuring that applications are processed in a timely fashion. This will be particularly important in defining the regulatory process with First Nations who hold land and who have approval or consultative rights along the pipeline right-of-way. These issues are currently being addressed in the development of the Mackenzie Gas Project. Many of the lessons learned from that project can be expected to be applicable to an Alaska gas pipeline project.

3. State Fiscal

The State of Alaska and the producers recognize the need to establish fiscal certainty for this high-risk project. The absence of clear and predictable methods to calculate royalty and tax payments to the State of Alaska over the life of a pipeline project represents a significant uncertainty. This uncertainty is highlighted by the experience of the oil industry in Alaska over the past 25 years. During that time, hundreds of millions of dollars were spent on litigation by the industry and the state.

That litigation was caused by differing interpretations of an ambiguous and complicated fiscal regime that resulted in the industry paying settlement costs of ~$6 billion [Source: Alaska Department of Resources, December 3, 2002 presentation]. An Alaska gas pipeline project cannot withstand such risk. An Alaska gas pipeline will have, at best, marginal economics and will not be able to withstand the risk that fiscal terms might increase as a result of new laws, regulations, or new interpretations of laws and regulations.

Establishing a simple, clear, and predictable fiscal framework for the project in the state of Alaska is necessary prior to significant further expenditures to mature a gas pipeline project. Some of the desired attributes of such a framework include:

- **Simplicity.** A minimum number of applicable agreements, regulations, and statutes, and reduced debate around netback valuation (e.g., utilizing FERC approved tariffs).

- **Clarity.** Common definition of parameters used to calculate the government take to minimize future negotiations and disputes (e.g., valuation of gas for royalty and severance taxes).

- **Predictability.** Assurance that the rules will not change once the gas pipeline investment is made, and that the producers can operate under a stable framework.

In April 2003, the State of Alaska reauthorized the Stranded Gas Development Act to allow negotiation of a binding fiscal contract for the development of Alaska's stranded gas resources. In addition to providing a process for establishing fiscal certainty, the Stranded Gas Development Act contemplates making changes to the existing fiscal terms to improve the competitiveness of an Alaska project in the marketplace. Such changes could enhance the commercial viability of an Alaska gas pipeline project.

4. Federal Fiscal Activity

In addition to the State of Alaska's efforts to address fiscal risk at the state level, the U.S. federal government is currently debating the need for a federal fiscal package. Potential elements of a fiscal package include:

- 7-year depreciation on the Alaska portion of the pipeline;

- A $0.52/MMBtu marginal well gas tax credit that begins to phase out at field prices above $0.83/MMBtu;

- Loan guarantees for up to 80% or $18 billion of construction costs.

There are differing views within industry on the likely cost of and need for a federal fiscal package and the NPC takes no position in this regard.

5. Market

There is also significant market uncertainty in terms of the demand for gas and the price customers will be willing to pay for natural gas over a 30+ year project life. For example, in the late 1970s it was expected that there would be sufficient demand for natural gas in the lower-48 and that prices would be sufficient to warrant construction of the ANGTS. However, by the early 1980s it was clear that the high-cost ANGTS project was not economic and could not be financed.

The risk associated with prices at the first market center downstream of the wellhead (e.g., Alberta) will likely be borne by the producers of North Slope gas. The amount of revenue these producers receive will be a direct function of the market price; yet producers will be obligated to pay fixed tolls to the pipeline owner, regardless of market conditions. Thus the producers, rather than the pipeline owners, will be at risk.

Figure S7-11 illustrates the uncertainty and recent volatility in natural gas prices. For an Alaska gas pipeline project to be commercially viable, the market outlook over a 30+ year life must be sufficiently encouraging to justify the large investment required.

III. Arctic Supply Assumptions for NPC Study

A. Canada

For purposes of this NPC study, it is assumed that the permitting, cost, and market hurdles identified earlier in this report will be overcome and that a Mackenzie Gas Project starts up in 2009 and transports the volumes shown in Figure S7-12.

While the initial volumes that might be transported by a Mackenzie Gas Project could range from 800 million cubic feet per day (MMCF/D) to 1,200 MMCF/D, for the purposes of this study it is assumed

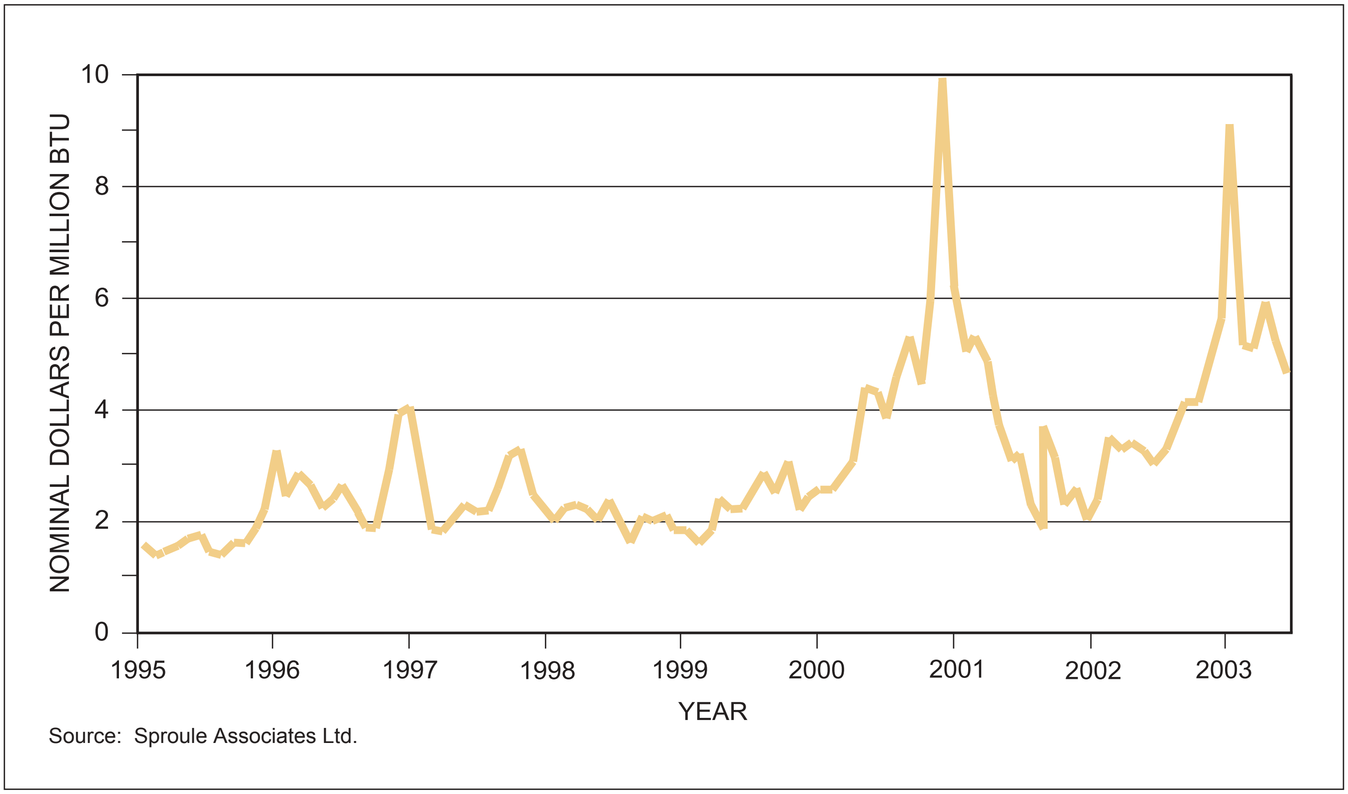


Figure S7-11. Henry Hub Monthly Index Prices

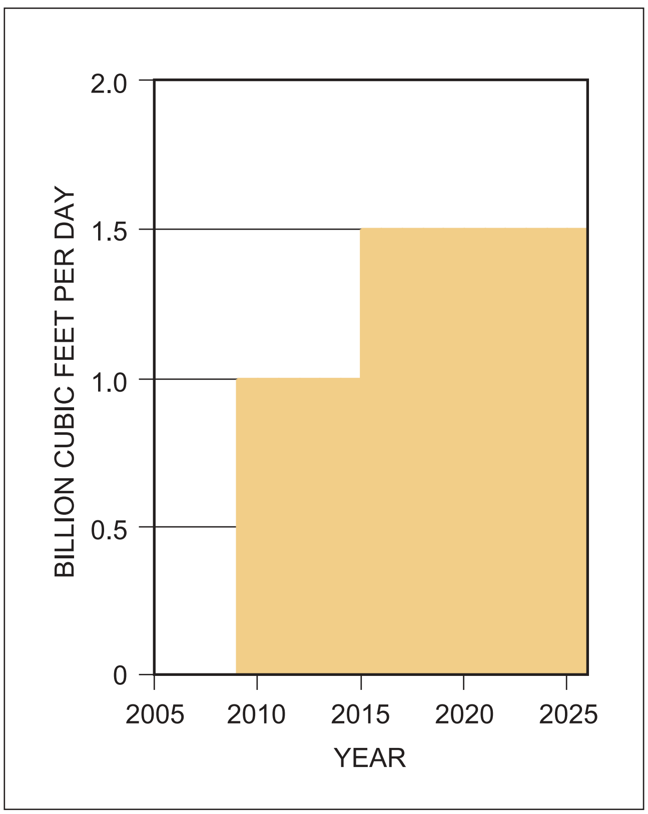


Figure S7-12. Canadian Arctic Gas Volumes

that the project would initially transport 1 BCF/D. This would consist of 800 MMCF/D a day of gas from three anchor fields (Taglu, Parson's Lake, and Niglintgak) as well as 200 MMCF/D from other fields. It is further assumed that additional economic discoveries of gas are made to allow expansion to 1.5 BCF/D in the year 2015 and to keep the line full through the end of the study period (2025). Between 2009 and 2025, a total of 8 TCF would be transported to market.

B. Alaska

For purposes of this NPC study, it is assumed that the permitting, state fiscal, cost, and market hurdles identified earlier in this chapter are overcome and that an Alaska gas pipeline project starts up in 2013 and transports Alaska gas to Alberta. From Alberta it is assumed that the gas is transported through a combination of existing pipeline capacity or newly installed capacity to markets in the lower-48 states. Figure S7-13 shows the volumes transported to Alberta. During the initial year (2013), it is assumed that only 2.5 BCF/D is transported as not all the compressor stations would be commissioned that first year. During the second and subsequent years a full 4.0 BCF/D

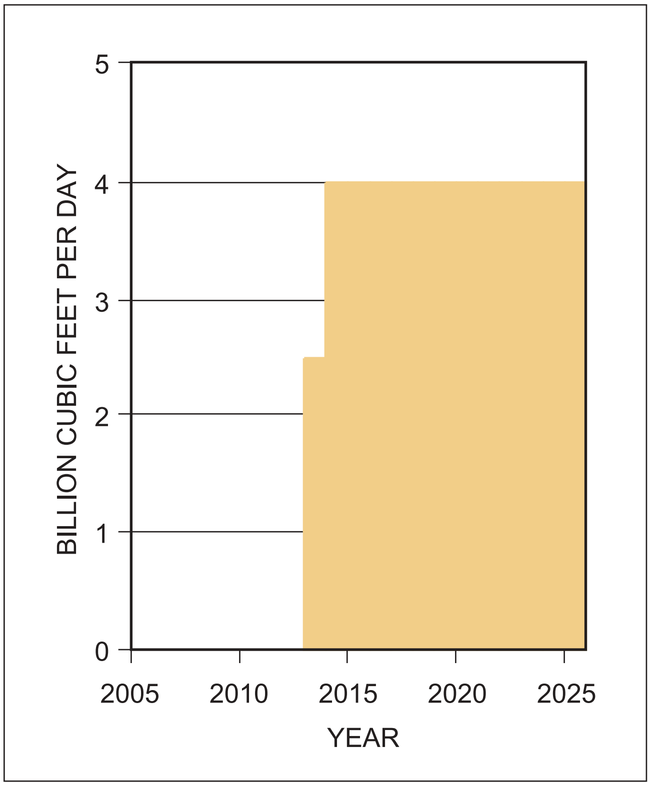


Figure S7-13. Alaskan Gas Volumes

would be transported. Between 2013 and 2025 a total of 18 TCF would be transported to market.

As indicated earlier, in addition to gas from known discoveries an additional 16 TCF of "yet-to-find" gas would be required to keep the pipeline full for a 30-year project life. In addition, the pipeline could be expanded if additional economic discoveries were made. This was addressed in the NPC study as a sensitivity.

Sensitivities. Three sensitivities on the construction of an Alaska gas pipeline were developed as part of the NPC study. For each of these sensitivities it was assumed that there was no change in the amount of LNG imports.

- **5-year delay in start-up (2018 vs. 2013).** This sensitivity was developed to illustrate the potential impact of a project delay that could result from delays in establishing the appropriate government frameworks or delays associated with securing the necessary permits or in resolving any resulting litigation. As a consequence of a delay, the model used by the NPC predicted that lower-48 natural gas prices would be approximately 15% higher from 2013 through 2017.

- **No Alaska gas pipeline.** This sensitivity illustrated the circumstance where an Alaska gas pipeline was not constructed during the study period. The model used by the NPC predicted that lower-48 gas prices would be approximately 15% higher from 2013 through 2017 and then 7% higher from 2020 through 2025.

- **1 BCF/D expansion in 2020.** This sensitivity illustrated that additional volumes could be absorbed by the lower-48 gas market if additional North Slope discoveries are made and if these discoveries are economical to develop.

IV. Recommendations

A. Industry

There are a number of actions that industry can take in order to facilitate the development of Arctic gas resources.

- **Industry should continue to pursue additional cost reduction opportunities.**

  Any reduction in the cost of building Arctic gas projects will improve the prospect of those projects being commercially viable.

- **Industry should continue to clearly communicate with governments the need for appropriate frameworks to reduce risks and uncertainties.**

  Industry is in a good position to identify the risks and uncertainties associated with major Arctic gas projects and to recommend actions that governments might take for reducing those risks and uncertainties.

B. Governments

There are also a number of actions that governments can take in order to facilitate the development of Arctic gas resources.

- **The U.S. government and the Canadian government should work together to encourage development of Arctic gas pipeline projects.**

  The governments of the United States and Canada should work cooperatively to facilitate the development of pipelines to transport Arctic gas to markets in both Canada and the United States. Both countries would realize material benefits for energy consumers in addition to the significant number of jobs, economic activity and government revenues. The laws, regulations, and policies established by both governments should allow for the timely development of these resources for the benefit of consumers in both countries.

- **The various governments in Canada (federal, territorial, and provincial) and the First Nations should continue to work cooperatively to develop and implement a clear and timely regulatory process. An efficient process must be in place in early 2004 to support a 2009 Mackenzie Gas Project start-up and a 2013 Alaska gas pipeline project start-up.**

  Establishing an efficient and coordinated regulatory process will help to secure timely issuance of the necessary permits for Arctic gas projects. The Canadian government should continue to support the implementation of this process by ensuring sufficient resources are made available to northern regulatory authorities to the review of applications and the issuance of permits and approvals.

- **The U. S. government should enact enabling legislation to reduce the risks and uncertainties associated with permitting an Alaska gas pipeline project. Enactment of enabling legislation in 2003 is required to support a 2013 project start-up.**

  Such legislation will create an efficient process for obtaining the necessary permits and authorizations for a project and will help ensure that a commercially viable pipeline project could be constructed as soon as possible. The following key features should be included:

  – Require FERC to expedite the issuance of a certificate to construct the pipeline once certain requirements under the Natural Gas Act have been met. Certificate to be issued within 20 months of a completed application.

  – Designate FERC as the lead agency for the National Environmental Policy Act or Environmental Impact Statement process.

  – Create a Federal Coordinator within the executive branch to coordinate the activities of the participating federal agencies.

  – Require that a single Environmental Impact Statement be utilized by all U.S. agencies.

  – Address limitations on the timing of potential legal challenges.

- **The U.S. government should finalize debate on a potential federal fiscal package for an Alaska gas pipeline project.**

  Regarding potential U.S. government fiscal policy changes, there is no consensus among industry or the U.S. government as to the need or scope of a federal fiscal package for an Alaska gas pipeline project.

- **The State of Alaska should enter into a fiscal contract with project sponsors that provides terms that are simple, clear, not subject to change and can improve project competitiveness. Contract approval by the Alaska legislature in 2004 is required to support a 2013 project start-up.**

  Establishing certainty on how state royalty and tax payments will be calculated will mitigate a significant risk to the commercial viability of an Alaska gas pipeline project. Enhancements to the fiscal terms to improve the competitiveness of an Alaska project in the marketplace could enhance the commercial viability of the project.

- **The U.S. government should allow wider access to acreage on the North Slope of Alaska for prudent resource and infrastructure development.**

  U.S. consumers would benefit by having additional domestic resources developed. These resources could be developed with a minimal footprint and minimal environmental impact.

- **Governments should avoid imposing mandates or additional restrictions that could increase costs and make it more difficult for a project to become commercially viable.**

  At times governments have imposed additional requirements on projects for political or other purposes. The imposition of such requirements could increase the cost of commercializing these Arctic resources and make it more difficult for a project to become commercially viable.

- **The U.S. and Canadian governments should study and/or consult with industry, and where appropriate directly address infrastructure improvements in advance of the time that these improvements would be required in support of Arctic gas development.**

APPENDICES

The Secretary of Energy
Washington, DC 20585

March 13, 2002

Mr. William A. Wise
Chairman
National Petroleum Council
1625 K Street, NW
Washington, DC 20006

Dear Chairman Wise:

In the last decade, the National Petroleum Council conducted two landmark studies on natural gas, the 1992 study ***Potential of Natural Gas in the United States*** and the 1999 study ***Meeting the Challenges of the Nation's Growing Natural Gas Demand***. These studies provided valuable insights on the potential contribution of natural gas to the Nation's economic, energy and environmental future, and the capabilities of industry to meet future natural gas demand and changing market conditions.

Considerable change has occurred in natural gas markets since the Council's 1999 study, among these being new concerns over national security, a changed near-term outlook for the economy, and turbulence in energy markets based on perceived risk, price volatility, fuel switching capabilities, and the availability of other fuels. The Nation's reliance on natural gas continues to grow, with U.S. consumption projected to increase by 50 percent in the next 20 years. However, the availability of investment capital and infrastructure, the pace of technology progress, access to the Nation's resource base, and new sources of supplies from Alaska, Canada, liquefied natural gas imports, and unconventional resources such as methane hydrates are factors that could affect the future availability of natural gas supplies.

Accordingly, I request that the Council conduct a new study on natural gas in the United States in the 21st Century. Such a study should examine the potential implications of new supplies, new technologies, new perceptions of risk, and other evolving market conditions that may affect the potential for natural gas demand, supplies, and delivery through 2025. It should also provide insights on energy market dynamics, including price volatility and future fuel choice, and an outlook on the longer-term sustainability of natural gas supplies. Of particular interest is the Council's advice on actions that can be taken by industry and Government to increase the productivity and efficiency of North American natural gas markets and to ensure adequate and reliable supplies of energy for consumers.

I am designating Mr. Robert G. Card, Under Secretary for Energy, Environment and Science, and Mr. Carl Michael Smith, Assistant Secretary for Fossil Energy, to represent me in the conduct of this important study. I offer my gratitude to the Council for its efforts to assist the Department in defining the scope of the study request and I recognize that refinements may be necessary after the study starts to ensure that the most critical issues affecting future natural gas demand, supplies, and delivery are addressed.

Sincerely,

Secretary Abraham

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 (NPC) 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 the Secretary, 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. The Council reserves the right to decide whether it will consider any matter referred to it.

Examples of studies undertaken by the NPC at the request of the Secretary of Energy include:

- *Factors Affecting U.S. Oil & Gas Outlook (1987)*
- *Integrating R&D Efforts (1988)*
- *Petroleum Storage & Transportation (1989)*
- *Industry Assistance to Government – Methods for Providing Petroleum Industry Expertise During Emergencies (1991)*
- *Short-Term Petroleum Outlook – An Examination of Issues and Projections (1991)*
- *Petroleum Refining in the 1990s – Meeting the Challenges of the Clean Air Act (1991)*
- *The Potential for Natural Gas in the United States (1992)*
- *U.S. Petroleum Refining – Meeting Requirements for Cleaner Fuels and Refineries (1993)*
- *The Oil Pollution Act of 1990: Issues and Solutions (1994)*
- *Marginal Wells (1994)*
- *Research, Development, and Demonstration Needs of the Oil and Gas Industry (1995)*
- *Future Issues – A View of U.S. Oil & Natural Gas to 2020 (1995)*
- *Issues for Interagency Consideration – A Supplement to the NPC's Report: Future Issues – A View of U.S. Oil & Natural Gas to 2020 (1996)*
- *U.S. Petroleum Product Supply – Inventory Dynamics (1998)*
- *Meeting the Challenges of the Nation's Growing Natural Gas Demand (1999)*
- *U.S. Petroleum Refining – Assuring the Adequacy and Affordability of Cleaner Fuels (2000)*
- *Securing Oil and Natural Gas Infrastructures in the New Economy (2001).*

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 Chair and a Vice Chair, who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

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APPENDIX B

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Supply Task Group B-7

Resource Subgroup B-8

Technology Subgroup B-11

Environmental/Regulatory/Access Subgroup B-11

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The National Petroleum Council wishes to acknowledge the numerous other individuals and organizations who participated in some aspects of the work effort through workshops, outreach meetings and other contacts. Their time, energy, and commitment significantly enhanced the study and their contributions are greatly appreciated.

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TASK GROUP REPORTS

ACRONYMS AND ABBREVIATIONS

AEO	EIA's Annual Energy Outlook
AEUB	Alberta Energy and Utilities Board
AFUE	annual fuel utilization efficiency
AGA	American Gas Association
ANGTA	Alaska Natural Gas Transportation Act of 1976
ANGTS	Alaska Natural Gas Transportation System
ANWR	Arctic National Wildlife Refuge
API	American Petroleum Institute
BACT	Best Available Control Technology
BCF	billion cubic feet
BCF/D	billion cubic feet per day
BLM	U.S. Bureau of Land Management
Btu	British thermal unit
CAPP	Canadian Association of Petroleum Producers
CC/CT	combined cycle/combustion turbine
CCGT	combined-cycle gas turbines
CEQ	Council on Environmental Quality
CERI	Canadian Energy Research Institute
CFE	Comision Federal de Electricidad (Mexico's Federal Electricity Commission
CFTC	Commodity Futures Trading Commission
CGPC	Canadian Gas Potential Committee
CHP	combined heat and power
CO2	carbon dioxide
COAs	conditions of approval
CRE	Comision Reguladora de Energia (Mexico's Energy Regulatory Commission)
CSS	cyclic steam stimulation
CZM	Coastal Zone Management
D&C	drilling and completion
DG	distributed generation
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
E&P	exploration and production
EEA	Energy and Environmental Analysis, Inc.
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency

EPCA	Energy Policy Conservation Act of 1975
ERCOT	Electric Reliability Council of Texas
EUR	estimated ultimate recovery
FCC	fluid catalytic cracking
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission (forerunner of FERC)
FTC	Federal Trade Commission
GDP	gross domestic product
GIIP	gas initially in place
GIP	gas in place
GMDFS	EEA's Gas Market Data and Forecasting System
GOM	Gulf of Mexico
GRI	Gas Research Institute
GSR	EEA's Gas Supply Review
GW	gigawatts
GWH	gigawatt hours
HCI	hydrocarbon indicator
HSM	EEA's Hydrocarbon Supply Model
HVAC	heating-ventilation-air conditioning systems
IECC	International Energy Conservation Code (superceded Model Energy Code in 1998)
IHS	IHS Energy Group
INGAA	Interstate Natural Gas Association of America
IP	industrial production
IP	initial production rate
ISTUM-2	Industrial Sector Technology Use Model
JAS	API's Joint Association Survey
KW	kilowatts
KWH	kilowatt hours
LDC	local distribution company
LIHEAP	Low Income Home Energy Assistance Program
LNG	liquefied natural gas
LSE	load serving entity
MACT	Maximum Achievable Control Technology
MCF	thousand cubic feet
MECS	EIA's Manufacturing Energy Consumption Survey
MEPS	Minimum Energy Performance Standards
MM	million
MMBtu	million British thermal units
MMCF	million cubic feet
MMCF/D	million cubic feet per day
MMS	Minerals Management Service
MOU	memorandum of understanding
MSC	Multiple Services Contract
MTA	million tons per annum
MTBE	methyl tertiary butyl ether
MW	megawatts
MWH	megawatt hours
NAECA	National Appliance Energy Conservation Act of 1987 and amendments of 1988
NAICS	North American Industry Classification System
NEB	National Energy Board of Canada

NECPA	National Energy Conservation Policy Act of 1978
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NGL	natural gas liquid
NGPA	National Gas Policy Act of 1978
NGV	natural gas vehicle
NOx	nitrogen oxides
NOAA	National Oceanic and Atmospheric Administration
NPC	National Petroleum Council
NPRA	National Petrochemical & Refiners Association
NPRA	National Petroleum Reserve, Alaska
NSR	EPA's New Source Review
NYMEX	New York Mercantile Exchange
OCS	Outer Continental Shelf
O&M	operation and maintenance
Pemex	Petroleos Mexicanos
PIFUA	Powerplant and Industrial Fuel Use Act of 1978
POLR	provider of last resort
PSA	EIA's Petroleum Supply Annual
PSAC	Petroleum Services Association of Canada
psi	pounds per square inch
PUC	public utility commission
PURPA	Public Utility Regulatory Policies Act of 1978
quads	quadrillion Btu
RACC	refiner acquisition cost of crude oil
R&D	research and development
REC	Renewable Energy Credit (or Certificate)
RFG	reformulated gasoline
ROE	return on equity
R/P	reserves to production (ratio)
RTOs	Regional Transmission Organizations
RPS	Renewable Portfolio Standards
SAGD	steam-assisted gravity drainage
SEDS	EIA's State Energy Data System
SENER	Secretaria de Energia (Mexico's Energy Ministry)
SIC	Standard Industrial Classification
SIP	state implementation plan
SOLR	supplier of last resort
SOx	sulfur oxides
SO_2	sulfur dioxide
TAPS	Trans-Alaska Pipeline System
TCF	trillion cubic feet
TRC	tradable renewable certificates
TW	terawatts
TWH	terawatt hours
USGS	United States Geological Service
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate crude oil

TASK GROUP REPORTS

GLOSSARY

Access
The legal right to drill and develop oil and natural gas resources, build associated production facilities, and build transmission and distribution facilities on either public and/or private land.

Basis
The difference in price for natural gas at two different geographical locations.

Capacity, Peaking
The capacity of facilities or equipment normally used to supply incremental gas or electricity under extreme demand conditions. Peaking capacity is generally available for a limited number of days at maximum rate.

Capacity, Pipeline
The maximum throughput of natural gas over a specified period of time for which a pipeline system or portion thereof is designed or constructed, not limited by existing service conditions.

City Gate
The point at which interstate and intrastate pipelines sell and deliver natural gas to local distribution companies.

Cogeneration
The sequential production of electricity and useful thermal energy from the same energy source, such as steam. Natural gas is a favored fuel for combined-cycle cogeneration units, in which waste heat is converted to electricity.

Commercial
A sector of customers or service defined as non-manufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions.

Compressed Natural Gas (CNG)
Natural gas cooled to a temperature below 32°F and compressed to a pressure ranging from 1,000 to 3,000 pounds per square inch in order to allow the transportation of large quantities of natural gas.

Cost Recovery
The recovery of permitted costs, plus an acceptable rate of return, for an energy infrastructure project.

Cubic Foot
The most common unit of measurement of gas volume; the amount of gas required to fill a volume of one cubic foot under stated conditions of temperature, pressure, and water vapor.

Distribution Line
Natural gas pipeline system, typically operated by a local distribution company, for the delivery of natural gas to end users.

Electric
A sector of customers or service defined as generation, transmission, distribution, or sale of electric energy.

End-User
One who actually consumes energy, as opposed to one who sells or re-sells it.

FERC (Federal Energy Regulatory Commission)
The federal agency that regulates interstate gas pipelines and interstate gas sales under the Natural Gas Act.

Firm Customer
A customer who has contracted for firm service.

Firm Service
Service offered to customers under schedules or contracts that anticipate no interruptions, regardless of class of service, except for force majeure.

Fuel Switching

Substituting one fuel for another based on price and availability. Large industries often have the capability of using either oil or natural gas to fuel their operation and of making the switch on short notice.

Fuel-Switching Capability

The ability of an end-user to readily change fuel type consumed whenever a price or supply advantage develops for an alternative fuel.

Gigawatts

One billion watts.

Henry Hub

A pipeline interchange near Erath, Louisiana, where a number of interstate and intrastate pipelines interconnect through a header system operated by Sabine Pipe Line. The standard delivery point for the New York Mercantile Exchange natural gas futures contract.

Industrial

A sector of customers or service defined as manufacturing, construction, mining, agriculture, fishing, and forestry.

Liquefied Natural Gas (LNG)

The liquid form of natural gas, which has been cooled to a temperature –256°F or –161°C and is maintained at atmospheric pressure. This liquefaction process reduces the volume of the gas by approximately 600 times its original size.

Load Profiles

Gas usage over a specific period of time, usually displayed as a graphical plot.

Local Distribution Company (LDC)

A company that obtains the major portion of its natural gas revenues from the operations of a retail gas distribution system and that operates no transmission system other than incidental connections within its own or to the system of another company. An LDC typically operates as a regulated utility within specified franchise area.

Marketer (natural gas)

A company, other than the pipeline or LDC, that buys and resells gas or brokers gas for a profit. Marketers also perform a variety of related services, including arranging transportation, monitoring deliveries and balancing. An independent marketer is not affiliated with a pipeline, producer or LDC.

New Fields

A quantification of resources estimated to exist outside of known fields on the basis of broad geologic knowledge and theory; in practical terms, these are statistically determined resources likely to be discovered in additional geographic areas with geologic characteristics similar to known producing regions, but which are as yet untested with the drillbit.

Nonconventional Gas

Natural gas produced from coalbed methane, shales, and low permeability reservoirs. Development of these reservoirs can require different technologies than conventional reservoirs.

Peak-Day Demand

The maximum daily quantity of gas used during a specified period, such as a year.

Peak Shaving

Methods to reduce the peak demand for gas or electricity. Common examples are storage and use of LNG.

Proved Reserves

The most certain of the resource base categories representing estimated quantities that 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; generally, these gas deposits have been "booked," or accounted for as assets on the SEC financial statements of their respective companies.

Regional Transmission Organization (RTO)

Voluntary organization of transmission owners, transmission users, and other entities interested in coordinating transmission planning, expansion, and use on a regional and interregional basis.

Residential

The residential sector is defined as private household establishments which consume energy primarily for space heating, water heating, air conditioning, lightning, refrigeration, cooking, and clothes drying.

Revenue

The total amount money received by a firm from sales of its products and/or services.

Shipper

One who contracts with a pipeline for transportation of natural gas and who retains title to the gas while it is being transported by the pipeline.

Terawatts

One trillion watts.

Watt

The common U.S. measure of electrical power.