OIL AND GAS RESOURCE ASSESSMENT METHODOLOGY

OVERSIGHT HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES

OF THE

COMMITTEE ON RESOURCES
U.S. HOUSE OF REPRESENTATIVES

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C O N T E N T S

OVERSIGHT HEARING ON "OIL AND GAS RESOURCE ASSESSMENT METHODOLOGY"

Thursday, April 18, 2002
U.S. House of Representatives
Subcommittee on Energy and Mineral Resources
Committee on Resources
Washington, DC

The Subcommittee met, pursuant to notice, at 10:37 a.m., in room 1334, Longworth House Office Building, Hon. Barbara Cubin, presiding.

Ms. CUBIN. I apologize for my tardiness in getting here today. We were in a tangle of traffic that is like one I have not seen since we have been in Washington. We will get right with it, because we have votes coming along. We have two. I guess that there are votes going on now. What I think we will do is make the opening statement; go to vote; and then come back and hear the testimony as quickly as we can.

STATEMENT OF THE HON. BARBARA CUBIN, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF WYOMING

The Subcommittee today meets to explore the basis for the regional oil and gas assessment approaches. The Secretary of the Interior, in consultation with the Secretaries of Agriculture and Energy, is completing an assessment of the oil and gas resource base on the Lower-48 Federal lands, together with an inventory of restrictions on accessing these resources. This action was mandated under Section 206 of the Energy Policy Act of 2000. Today's hearing will primarily focus on the Rocky Mountain region where the controversy over oil and gas assessment methods has recently arisen.

Congress and the executive branch need an objective scientific analysis of the oil and the gas potential of the public lands, together with a full understanding of the impediments to exploration and development. Without such an analysis, we cannot rationally debate options for meeting domestic supply requirements for natural oil and gas.

The Rocky Mountains are a frontier gas province with about 85 percent of its known gas reserves still in the ground. A National Petroleum Council assessment in 1999 estimated that 40 percent of the natural gas resource in this province is affected by access restrictions. However, since the NPC study, new land withdrawals

for national monuments and in roadless areas have further impacted natural gas resources in the Rockies. In the later case, an analysis by the Department of Energy has shown that an additional estimated 11.3 trillion cubic feet of technically recoverable natural gas is affected by roadless withdrawal areas.

In February, an independent research group, RAND, released an interim report which criticized the current oil and gas resource assessments of the Rocky Mountains as overly optimistic, primarily because they believe too few economic factors are considered. RAND concluded that only economically viable resources should be considered in regional oil and gas assessments.

RAND plans to perform its own analysis of the oil and gas resource base in the Intermountain West, along with an examination of the opportunities and constraints on development. This private study will apparently duplicate the Section 604 inventory of oil and gas resources in the Rocky Mountain region. The Hewlett Foundation has given RAND a $450,000 grant for this work. Will the RAND oil and gas assessment improve upon the Section 604 inventories? Many believe that the oil and gas assessment methodology is inherently conservative and, more often than not, leads to under-estimation, rather than over-estimation, of recoverable hydrocarbons.

An example of this is in the Powder River Basin coal bed methane play in my own State of Wyoming. The USGS estimated in 1995 that the technically recoverable CBM resource in the Powder River Basin was 1.11 trillion cubic feet. After production increased from less than 6 billion cubic feet in 1996 to nearly 16 billion cubic feet in 1998, the USGS raised the estimate of the technically recoverable CBM resources to more than 14 trillion cubic feet. Production has continued to expand rapidly, and now exceeds 250 Bcf annually.

The Wyoming State Geological Survey now estimates that technically recoverable CBM resources in the Powder River Basin are 25 Tcf—trillion cubic feet. And the USGS will undoubtedly raise their estimate for the CBM in the Powder River Basin when they revise their own oil and gas assessments.

While economic considerations are important, an economic assessment on the scale proposed by RAND requires economic information on the nature and the siting of the deposit at a detail that is simply not known from regional assessment. Short-term changes in a number of factors such as market price, discount rate, and the cost of the capital, can dramatically affect an economic assessment. Thus, the economic assessment is even more uncertain than the underlying mineral assessment based on the geologic and engineering factors alone.

The Jonah Gas Field in Wyoming is a good illustration of the problem with this approach. A small oil company decided to explore an area in the Green River Basin which others had drilled and abandoned before. The target was an unconventional basin-centered gas play of the type that RAND apparently believes contain little in the way of viable resources. A field producing 700 million cubic feet of natural gas per day has now been developed. But Jonah may never have been deemed viable and made viable for de-

velopment if BLM land use decisions had been grounded in RAND-type assessments.

The crux of the debate over the viability of oil and gas resource assessments for Federal land policymakers is the use of economic viability factors to prejudice where and when entrepreneurial explorationists ought to be allowed to search for domestic oil and gas. My concern is that an economic viability screen, like the one posed by RAND, will be used as the basis for denying drilling permits for the underdeveloped prospects that could become the next Jonah.

Will America thwart risk-taking by our domestic industry in the pursuit of new types of hydrocarbon reservoirs by basing land use planning decisions on government assessments of economic oil and gas? I certainly hope not. Government must allow dry holes to be drilled by the risk-takers searching for the next giant field to replace our declining domestic production.

I believe this was the intent of the 106th Congress which asked for the Section 604 inventory which—do not forget—was signed into law by Bill Clinton, not George Bush. Joe Skeen and I were sponsors of a very similar provision in H.R. 1985, which was added to the Energy Policy Act of 2000 by Senator Murkowski. Our choice of words, "resources" as well as "reserves," was intended to ensure that meaningful data would be forthcoming from inventory.

Let's not undercut that effort before it is even completed by insisting that only the least risky and most certain resources are reported to Congress. We are truly capable of determining the merits of the various access restrictions, when armed with the facts. If shielded from them, we are merely making legislation in the dark—a choice that I hope that we could all agree is very ill advised, and not representing the best of ourselves for the people.

[The prepared statement of Ms. Cubin follows:]

Statement of The Honorable Barbara Cubin, Chairman, Subcommittee on Energy and Mineral Resources

The Subcommittee meets today to explore the basis for regional oil and gas assessment approaches as the Secretary of the Interior, in consultation with the Secretaries of Agriculture and Energy, is completing an assessment of the oil and gas resources base on all lower–48 Federal lands, together with an inventory of the restrictions on accessing these resources.

This action was mandated under Section 604 of the Energy Policy Act of 2000. Today's hearing will primarily focus on the Rocky Mountain region, where controversy over oil and gas assessment methods has recently arisen.

Congress and the Executive Branch need an objective scientific analysis of the oil and gas potential of public lands, together with a full understanding of impediments to exploration and development. Without such an analysis, we cannot rationally debate options for meeting domestic supply requirements for natural gas and oil.

The Rocky Mountains are a frontier gas province with about 85 percent of its known gas reserves still in the ground. A National Petroleum Council (NPC) assessment in 1999 estimated that 40 percent of the natural gas resource in this province is affected by access restrictions.

However, since the NPC study, new land withdrawals for national monuments and in roadless areas have further impacted natural gas resources in the Rockies. In the latter case, an analysis by the Department of Energy has shown that an additional estimated 11.3 trillion cubic feet (Tcf) of technically recoverable natural gas is affected by roadless area withdrawals.

In February, an independent research group, RAND, released an interim report which criticized current oil and gas resource assessments of the Rocky Mountains as overly optimistic, primarily because they believe too few economic factors are con-

sidered. RAND concluded that only economically "viable" resources should be considered in regional oil and gas assessments.

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Will the RAND oil and gas assessment improve upon the Section 604 inventories? Many believe that oil and gas assessment methodology is inherently conservative, and more often than not, leads to underestimation—rather than overestimation—of recoverable hydrocarbons.

An example of this is the Powder River Basin coalbed methane (CBM) play in my own State of Wyoming. The USGS estimated in 1995 that the technically recoverable CBM resource in the Powder River Basin was 1.11 Tcf. After production increased from less than 6 billion cubic feet (Bcf) in 1996 to nearly 16 Bcf in 1998, the USGS raised its estimate of technically recoverable CBM resources to more than 14 Tcf. Production has continued to expand rapidly and now exceeds 250 Bcf annually.

The Wyoming State Geological Survey now estimates that technically recoverable CBM resources in the Powder River Basin are 25 Tcf, and the USGS will undoubtedly raise their estimate for CBM in the Powder River Basin when they do their next oil and gas assessment.

While economic considerations are important, an economic assessment on the scale proposed by RAND requires economic information on the nature and siting of the deposit at a detail that is simply not known from a regional assessment. Short term changes in a number of factors such as market price, the discount rate and the cost of capital can dramatically affect an economic assessment. Thus, the economic assessment is even more uncertain than the underlying mineral assessment based on geologic and engineering factors alone.

The Jonah Gas Field in Wyoming is a good illustration of the problem with this approach. A small oil company decided to explore an area in the Green River Basin which others had drilled and abandoned before. The target was an "unconventional basin-centered" gas play of the type that RAND apparently believes contain little in the way of "viable" resources. A field producing 700 million cubic feet of natural gas per day has now been developed. But Jonah may never have been deemed viable and made available for development if BLM land-use decisions had been grounded in RAND-type assessments.

The crux of the debate over the utility of oil and gas resource assessments for Federal land policy makers is the use of economic viability factors to pre-judge where and when entrepreneurial explorationists ought to be allowed to search for domestic oil and gas. My concern is that an "economic viability"screen like the one proposed by RAND will be used as the basis for denying drilling permits for undeveloped prospects that could become the next Jonah.

Will America thwart risk-taking by our domestic industry in the pursuit of new types of hydrocarbon reservoirs by basing land use planning decisions on a government assessment of economic oil and gas? I certainly hope not. Government must allow dry holes to be drilled by risk-takers searching for the next giant field to replace our declining domestic production.

I believe this was the intent of the 106th Congress which asked for the Sec. 604 inventory which—do not forget—was signed into law by Bill Clinton, not George W. Bush. Joe Skeen and I were sponsors of a very similar provision in H.R. 1985 which was added to the Energy Policy Act of 2000 by Sen. Murkowski. Our choice of words, resources as well as reserves, was intended to insure that meaningful data would be forthcoming from the inventory.

Let's not undercut that effort before it is even completed by insisting that only the least risky and most certain resources are reported to Congress. We are fully capable of debating the merits of various access restrictions when armed with the facts. If shielded from them, we are merely legislating in the dark—a choice I would hope we could all agree is ill-advised.

Ms. CUBIN. Before we go take our vote, I would like to submit for the record Ranking Member Ron Kind's opening statement. It will be available for all of you to read.

[The prepared statement of Mr. Kind follows:]

Statement of The Honorable Ron Kind, a Representative in Congress from the State of Wisconsin

I would like to begin by thanking our Chair, Representative Cubin, for scheduling today's oversight hearing on methodologies in oil and gas assessments of Federal lands.

The Hewlett Foundation and the RAND Corporation are also to be commended for the invaluable assistance they are providing as Congress develops a new national energy policy.

RAND's work will not replace or supplant the credible assessment work done by the Federal Government. Instead, it will enhance and increase its value to decision-makers at all levels of government and the private sector.

As I read through the testimony, however, I was struck by the confusion that continues to exist on the definitions used to conduct resource assessments.

For instance, Section 604 of Public Law 106–459, also referred to as the EPCA study, directs the Secretary of the Interior to identify, and I quote, "the Untied States Geological Survey reserve estimates of the oil and gas resources underlying those [onshore Federal] lands."

The key phrase here being "reserve estimates." While there is no legislative history for this provision of law, according to the Department of Energy, and most technical literature, reserves of crude oil and natural gas are the estimated quantities that, on a particular date, are demonstrated with reasonable certainty by geological and engineering data to be recoverable in the future, from known reservoirs under existing economic and operating conditions.

Unlike the EPCA resource assessment being developed by the Administration, there is a probability associated with a proved reserves estimate. Generally, there is at least a 90 percent probability that, at a minimum, the estimated volume of proved reserves in the reservoir can be recovered under existing economic and operating conditions.

Therefore, considering that the assessment being conducted by the USGS and the BLM will instead a very rough estimate of resource deposits at generally low confidence—policy makers will require a more detailed set of conclusions as to what portion of these "technically recoverable" undiscovered resources are of significant size and volume to warrant oil and gas leases, and whether economic and environmental conditions would justify such action.

In sum, I believe the RAND study on oil and gas resource assessment in the Intermountain West is an improvement on the current assessment practices used by the USGS and the BLM.

Ms. CUBIN. We will be back after the last vote, as quickly as we can. I don't know how many there are. So we will be gone about a half an hour, and then we will be back. Thank you for your patience, and we will see you after while.

[Recess.]

Ms. CUBIN. Well, I thank all of the witnesses for being here today with us, and for all of the patience that they have been extending our way. We hope to get this moving in a smooth fashion now and save your time, because I know we all have important things to do.

I would like to now recognize the first panel of witnesses, the Honorable Kathleen Clarke, Director of the Bureau of Land Management; accompanied by Mr. Erick—Help me there, Erick—

Mr. KAARLELA. Kaarlela.

Ms. CUBIN. —Kaarlela, National Office Director of the BLM; and Ms. Suzanne Weedman, Energy Resources Program Coordinator, with the USGS.

The Chair now recognizes Director Clarke to testify for 5 minutes. The timing lights on the table will indicate when your time is concluded. All witnesses' statements that are not able to be completed orally will be included in the record.

And reminding the members of the Committee that Committee Rule 3(c) imposes a 5-minute limit on questions. The Chairman will recognize only members for that amount of time.

So with that, I ask Ms. Clarke to begin testimony.

STATEMENT OF KATHLEEN CLARKE, DIRECTOR, BUREAU OF LAND MANAGEMENT; ACCOMPANIED BY ERICK KAARLELA, NATIONAL ENERGY OFFICE DIRECTOR, BUREAU OF LAND MANAGEMENT; AND SUZANNE WEEDMAN, ENERGY RESOURCES PROGRAM COORDINATOR, U.S. GEOLOGICAL SURVEY

STATEMENT OF KATHLEEN CLARKE

Ms. CLARKE. Madam Chairman, members of the Subcommittee, thank you for the opportunity to appear here today to discuss the ongoing Energy Policy and Conservation Act (EPCA) scientific inventory. Madam Chairman, I also want to thank you for your leadership and that of your Committee in initiating and directing the EPCA effort. Today I am accompanied by Erick Kaarlela, who is overseeing the BLM Energy Office; and Suzanne Weedman, with USGS.

In order to provide for our nation's vital and growing energy needs, the Department of the Interior, and the BLM in particular, are working hard to fulfill our important responsibilities in implementing the National Energy Policy as designed by the President. Recognizing that portions of the Federal onshore lands are off-limits to energy development or are open only to limited development, the President's policy included a specific recommendation for the Department of the Interior to review its land status and lease stipulations regarding oil and gas development on Federal lands.

In addition, the policy directed the Department, consistent with existing laws, sound environmental practices, and balanced use of other resources, to look for potential modifications to foster oil and gas development and production. As part of these efforts, the Department also was directed to ensure full and meaningful consultation with the public, particularly with local communities, while reviewing the information and considering possible modifications.

The ongoing EPCA inventory of oil and gas resources and reserves and their access impediments was specifically highlighted to be expedited by the involved Federal agencies as part of the President's National Energy Policy directives. Each agency involved in the EPCA inventory project has specific responsibilities associated with the study.

The BLM is supplying Federal land status and oil and gas lease stipulation information from existing resource management plans. The Forest Service is supplying lease stipulation information from their forest plans. The USGS is contributing the undiscovered oil and gas resource data, and is working to update these data in support of the EPCA inventory. The Department of Energy is contributing proven oil and gas reserves data.

The inter-agency EPCA Steering Committee identified five basins within the Rocky Mountain region as the priority geographic areas for this study. They are the Powder River Basin, the Green River Basin, Uinta/Piceance and San Juan/Paradox Basins, and the Mon-

tana Thrust Belt. The selection of these priority basins was based on industry interest, the USGS resource potential rankings, energy reserve rankings, and the BLM and Forest Service oil and gas needs analysis. In response to the President's National Energy Policy directive to expedite the EPCA study, we are performing the analysis for each basin concurrently.

To achieve the data collection and analysis, a contract was issued in December of 2001 to a private contractor, Advanced Resources International, to perform work for the EPCA study. Work on the project is proceeding on schedule, to meet Congress' mandate for the completion of the report by the end of this year.

It is important to point out that the EPCA study is not a decision document. All of the information gathered as a result of the EPCA effort will be analyzed and, as appropriate, integrated into BLM's ongoing land use planning efforts, and will include extensive public participation. By integrating the information into BLM's planning process, additional opportunities are available for the public to comment and provide recommendations on the specific information and how it might be used. In no case will any of these recommendations made as a result of the studies preclude full compliance with statutory environmental review and protections, including the National Environmental Policy Act.

The BLM will review the EPCA findings regarding land status and lease stipulations, and analyze their effects on the availability of oil and gas resources for development. Data from the EPCA inventory will be used to evaluate potentially overly restrictive impediments, to determine if alternative methods are available that can still provide comparable and sound environmental protection.

As directed by the President's energy policy, any potential modifications must be consistent with the existing laws, with sound environmental practice, and the balanced use of other resources; and performed with full public participation, especially at the local level.

It should be emphasized that as the BLM works on reviewing EPCA information and considers potential land use planning modifications, we will continue to abide by FLMPA's principles of multiple use, sustained yield, and environmental protection. These are standards to which the BLM is completely committed. The BLM will only consider opportunities to increase access to oil and gas resources while still maintaining multiple-use values, including surface and subsurface resource values, and appropriate environmental protection.

The BLM is committed to fulfilling its role in diversifying America's energy supplies and ensuring the environmentally responsible production and distribution of our nation's energy resources. The EPCA inventory is a key component of our efforts to fulfill these responsibilities and to implement the President's National Energy Policy, in order to continue to provide a secure energy future for our country.

Thank you for the opportunity to testify.

[The prepared statement of Ms. Clarke follows:]

Statement of Kathleen Clarke, Director, Bureau of Land Management, U.S. Department of the Interior

Madam Chairman and Members of the Subcommittee, thank you for the opportunity to appear here today to discuss oil and gas resource assessments, and the Energy Policy and Conservation Act (EPCA) study, in particular. I want to thank you, Madam Chairman, for your leadership as well as that of your Subcommittee, in directing the EPCA scientific inventory.

I am accompanied by Erick Kaarlela, the Bureau of Land Management's (BLM's) National Energy Office Director and Suzanne Weedman, the U.S. Geological Survey's Energy Resources Program Coordinator. Erick and Suzanne have been involved with the EPCA effort since its inception and they are here to assist in answering your questions.

NATIONAL ENERGY POLICY IMPLEMENTATION

As this Subcommittee knows well, the nation's Federal lands contain a large portion of U.S. energy resources. In order to provide for our nation's vital and growing energy needs, the Department of the Interior, and the BLM in particular, are working hard to fulfill our important responsibilities in implementing the President's National Energy Policy. Over a quarter of the President's energy policy recommendations specifically relate to one or more of the BLM's energy, mineral, and planning-related responsibilities. To systematically carry out the President's policy and goals, the BLM has identified more than 40 tasks to facilitate domestic production and transmission of both renewable and non-renewable energy resources, while ensuring environmental protection.

Recognizing that portions of Federal onshore lands are off-limits to energy development or are open only to limited development, the President's policy included a specific recommendation for the Department of the Interior to review its land status and lease stipulations regarding oil and gas development on Federal lands. In addition, the policy directed the Department—consistent with existing laws, sound environmental practices, and balanced use of other resources—to look for potential modifications to foster oil and gas development and production. As part of these efforts, the Department also was directed to ensure full and meaningful consultation with the public, particularly with local communities, while reviewing the information and considering possible modifications. The ongoing EPCA inventory of oil and gas resources and reserves and their access impediments was specifically highlighted to be expedited by the involved Federal agencies as part of the President's National Energy Policy directives.

EPCA STUDY

Since enactment of the Energy Policy and Conservation Act Reauthorization of 2000, the Department of the Interior has been working expeditiously to complete the EPCA study requirements and comply with the Congressional directive. The BLM, as lead agency of the effort, is working closely with the U.S. Geological Survey (USGS), U.S. Forest Service (USFS), the Department of Energy (DOE), and DOE's Energy Information Administration (EIA), to produce a scientific inventory of the oil and gas resources and reserves underlying onshore Federal lands and to identify the extent and nature of any restrictions or impediments to their development. An interagency EPCA Steering Committee composed of senior staff of each agency was created to ensure an effective process for close coordination and collaboration between the participating agencies.

EPCA METHODOLOGY

Scope/Outreach

Early discussions among the interagency EPCA Steering Committee focused on the scope of the study. This included identifying current information and ongoing efforts, integrating the various agency roles and functions, developing common approaches and consistent methods for reserve and resource determination, and identifying the top priority geographic areas for study and analysis. The group also made an initial inventory of the nation's oil and gas resources and reserves on Federal lands and determined those basins of greatest oil and gas development potential for further analysis.

An important aspect of the initial development of the EPCA project was gathering feedback from interested parties. As the EPCA effort progressed, meetings were held with the oil and gas industry, the environmental community, and Congressional staff regarding the initial efforts of the project and the plan for completing the inventory.

Agency Responsibilities & Inventory Approach

Each agency involved in the EPCA inventory project has specific responsibilities associated with the study. The BLM is supplying Federal land status and oil and gas lease stipulation information from existing Resource Management Plans. The USFS is supplying lease stipulation information from their Forest Plans. The USGS is contributing the undiscovered oil and gas resource data and is working to update these data in support of the EPCA inventory. The EIA, meanwhile, is contributing proven oil and gas reserves data.

The methodology adopted was first to have the USGS and EIA utilize their expertise in resource and reserve estimation in making the required initial inventory of resources. Next, the BLM and USFS would conduct inventories of the various impediments to and restrictions on development on Federal lands. Using the information provided through these first two steps, and utilizing Geographical Information Systems and other advanced computer technologies, the group is able to map the amount of resources and reserves that are associated with the identified restrictions and impediments. These areas then are characterized according to the degree to which the restrictions and impediments may affect development.

Geographic Priorities

The interagency EPCA Steering Committee identified five basins within the Rocky Mountain Region as the priority geographic areas for study. They are the Powder River, Green River, Uinta/Piceance, and San Juan/Paradox Basins, and the Montana Thrust Belt. The selection of these priority basin areas was based on industry interest, USGS resource potential ranking, EIA reserve ranking, and the BLM and USFS oil and gas need analysis. In response to the President's National Energy Policy directive to expedite the EPCA study, we decided to perform the analysis for each basin concurrently.

Contractor Involvement/Schedule

To achieve the data collection and analysis, a contract was issued in December 2001 to a private contractor, Advanced Resources International (ARI), to perform required work for the EPCA study. ARI also brought in Premier Data Services as a subcontractor to aid in the data collection phase. Work on the EPCA project is proceeding on schedule to meet Congress' mandate for completion of the EPCA report by the end of this year.

USE OF EPCA INVENTORY INFORMATION

It is important to point out that the EPCA study is not a "decision" document. All information gathered as a result of the EPCA effort will be analyzed and, as appropriate, integrated into the BLM's ongoing land use planning efforts, which include extensive public participation. By integrating the information into the BLM's planning process, additional opportunities are available for the public to provide comments and recommendations on the specific application of the information. In no case will any recommendations made as a result of these studies preclude full compliance with statutory environmental review and protections, including the National Environmental Policy Act.

As the information becomes available from the EPCA inventory, the BLM plans to analyze the data for opportunities to improve the Bureau's management of the oil and gas resources on Federal lands. Direction will be provided to BLM Field Offices on how best to apply the EPCA information to facilitate environmentally-responsible development of oil and gas resources, both in the BLM's land-use planning process and the daily management of the public lands and its resources. This analysis and the development and consideration of potential modifications is one of the BLM's critical tasks in implementing the President's National Energy Policy directives.

It should be emphasized that as the BLM works on reviewing the EPCA information and considers potential land-use planning modifications, we will continue to abide by the Federal Land Management and Policy Act's principles of multiple-use, sustained yield, and environmental protection. These are standards to which the BLM is completely committed. The BLM will only consider opportunities to increase access to oil and gas resources while still maintaining multiple-use values, including surface and subsurface resource values (such as aquifers and other minerals), and appropriate environmental protection.

The BLM will review the EPCA inventory's findings regarding land status and lease stipulations, and analyze their effects on the availability of oil and gas resources for development. Data from the EPCA inventory will be used to evaluate potentially overly-restrictive impediments to determine if alternative methods are available that can still provide comparable and sound environmental protections. As

directed by the President's National Energy Policy, any potential modifications must be consistent with existing laws, good environmental practice, the balanced use of the other resources and performed with full public participation, especially at the local level.

Public Outreach

As mentioned, public participation is a critical part of the EPCA project. In March, the BLM held a productive National Energy Plan Outreach Meeting in Denver, Colorado, to gather input from all interested parties on the more than 40 tasks associated with the BLM's implementation of the President's National Energy Policy. The outreach meeting was well-attended by representatives from environmental groups, industry, the general public, as well as State and other Federal agencies.

As part of the outreach meeting, a presentation on the EPCA study and use of the EPCA inventory was conducted. The BLM requested specific comments from participants on how to make the EPCA project responsive to the needs of our stakeholders. The BLM is currently reviewing and evaluating comments for possible application to its efforts to implement the President's National Energy Policy. The BLM is planning additional outreach meetings to solicit further comments and recommendations for consideration related to its implementation of the President's National Energy Policy, including its efforts related to the EPCA project.

CONCLUSION

The BLM is committed to fulfilling its role in diversifying America's energy supplies and ensuring the environmentally-responsible production and distribution of our nation's energy resources. The EPCA inventory project is a key component in our efforts to fulfill these responsibilities and to implement the President's National Energy Policy in order to continue to provide a secure energy future for our country.

Madam Chairman, thank you for the opportunity to testify before you today. We welcome any questions the Subcommittee may have.

[Responses to questions submitted for the record by Ms. Clarke follow:]

Responses to Subcommittee Follow–Up Questions

OVERSIGHT HEARING ON OIL & GAS RESOURCE ASSESSMENT METHODOLOGY

House Resources Subcommittee on Energy and Mineral Resources

APRIL 18, 2002

Questions from the Majority

1. A lot has been said about including non-federal lands in EPCA oil and gas assessments. Isn't the starting point for any regional assessment an assessment of all land within a region regardless of ownership?

The EPCA study utilizes data from U.S. Geological Survey's (USGS) 1995 National Oil and Gas Assessment, which covers all lands regardless of ownership, as a starting point. As a part of the analysis, the resources were calculated for Federal lands, as the statute requires, and for non–Federal lands as well. The non–Federal portion will be displayed in the final EPCA report as surface acreage and as an aggregate amount of resource for each of the five study areas so that the relative contribution of non–Federal lands within the inventory area can be compared to that of the Federal lands.

2. In your testimony, you briefly describe how BLM will use the results of EPCA Phase 1. Would you elaborate on how EPCA will be implemented?

As the results of the EPCA study become available, the information will be provided to BLM and US Forest Service managers, resource specialists, and technical experts for their review and consideration. The EPCA study will provide a sound scientific base from which these land management agencies can analyze the various options regarding oil and gas development on public lands. This information will supplement existing data being used in the preparation of land use plans, and it will be considered for current land use decisions and approvals. The BLM will also use the EPCA inventory as a basis to reassess the appropriateness and effectiveness

of our leasing and operational decisions, and the priority areas for such a reassessment.

Specifically, the BLM will use the EPCA information following Federal Land Policy and Management Act's (FLPMA) multiple-use mandate for making balanced decisions regarding land availability for oil and gas development in an environmentally-sound manner. Additionally, we will use the information to make decisions on appropriate and needed stipulation waivers and modifications as provided by regulations and consistent with existing land use plans. The EPCA study will provide both the public and the Federal decision-makers with substantive information about the oil and gas resources.

3. Are you including split estate lands, in which the Federal Government owns the minerals and the surface is private, and private lands within the study? How does BLM treat split estate lands when an Application for Permit to Drill is received from an oil and gas operator?

Split estate lands—where the oil and gas mineral estate is Federally-owned regardless of surface ownership—are being included in the EPCA study. Split estate lands are analyzed in the same manner as Federally-owned surface lands in the inventory.

Oil and gas operations on Federal split estate resources are subject to the same environmental laws and regulations that are applicable to Federally-owned surface lands. The permitting process also is generally the same. However, regarding private surface involvement, an operator is required to submit as part of its Surface Use Plan one of the following—a copy of the signed surface owner agreement between the operator and the surface owner; a certification by the operator that an agreement was reached with the surface owner; or a certification of compliance with Federal regulations (43 CFR 3814) with respect to bonding requirements for use of the surface. In addition, the BLM requests that operators, prior to onsite inspections, contact surface owners and notify them of their proposed activity. In particular, the BLM asks operators to invite surface owners to on-site inspections. Operators must incorporate the landowner concerns or desires for mitigation, existing road use, and abandonment into the Surface Use Plan of the APD.

4. Let me ask a hypothetical question. Much of the controversy over the EPCA studies is focused on the technically- versus economically-recoverable oil and gas resources. Would BLM be able to complete the Federal lands analysis without trying to quantify oil and gas resource estimates, in other words, only generally determine oil and gas potential, such as high, medium and low? Would the results of such a study provide meaningful conclusions that could be used by BLM in making informed land management decisions?

In order to determine oil and gas potential on a consistent basis, the same data would have to be used as was employed by the USGS for its 1995 National Oil and Gas Assessment. No maps or studies are currently available that classify the lands within the United States on a consistent basis as to their "high," "medium," or "low" potential for oil and gas. We believe that stacking the resource plays and quantifying the resource volumes, as will be shown by maps in the completed inventory, will adequately categorize the oil and gas potential of the lands within the study areas.

Making judgments as to classifying lands as having "high," "medium," or "low" potential would entail the evaluation of widely varying opinions based on speculative economic assumptions. The approach being used in the EPCA inventory responds to the Congressionally-mandated requirement and we feel will be extremely valuable in making informed Federal land management decisions.

5. Some have criticized the NPC study as biased towards the oil industry. Does the USGS seek industry input when making their oil and gas assessments? Does the participation of the industry improve an oil and gas assessment?

Until 1989, the USGS conducted oil and gas resource assessments alone, without much consultation with private industry. However, after a review by the National Research Council, the USGS was advised to seek input and review of its methodology from industry. The agency now does that. Most of the USGS information about past oil and gas production today comes from commercial databases, derived from industry sources, and from the Energy Information Administration. Additionally, USGS sometimes receives both public and proprietary data from private industry. While USGS does acquire data and information from private industry, the resource assessments are conducted solely by USGS geologists and engineers.

USGS resource methodology has been reviewed and approved by the Committee of Resource Evaluation of the American Association of Petroleum Geologists, a professional society of academic, Federal, and private industry petroleum geologists. No

one from industry or from another agency is allowed to participate in USGS assessment meetings to avoid any conflicts of interest, or the perception of conflicts of interest. Having industry review USGS methodology has generally improved industry's respect for and acceptance of USGS assessment results. Obtaining more detailed geologic information from industry also has improved the quality of the USGS assessments.

6. Is the 1998 USGS economic evaluation (Attanasi) of the 1995 national assessment still valid?

The 1998 USGS economic evaluation of the1995 National Oil and Gas Assessment is slightly out of date with respect to both natural gas resource estimates and to economic assumptions. The resource data have a 1992–1994 vintage and the USGS is currently in the process of updating these resource estimates. Also, the costs of finding, developing, and producing oil and gas, as well as estimates of the typical success rates, are taken from the same time period. Clearly, many advances in exploration for natural gas, especially unconventional gas, have taken place since the mid–1990s.

Results of the USGS update of the resource assessment completed in 1995 should be available over the next few years. When they are complete, the USGS will conduct an economic evaluation of the results.

Questions from the Minority

1. Director Clarke, Section 604 of EPCA directs the Secretary to identify the "reserve estimate" of the onshore oil and gas resource. Yet, USGS and BLM have identified, instead, the undiscovered, technically recoverable resource. This is a highly speculative and broad category. Additionally, it is not consistent with the language of the law.

Basically, using the undiscovered technically recoverable classification will yield a best guess given the available data and will also produce maps covering a much wider area.

In contrast, using reserve estimates of oil and gas—or even the economically recoverable resources would provide a greater certainty that such lands contain oil and gas in quantities that will warrant development.

Why then would you conclude that Congress intended that the assessment be based on the highly speculative, broad category of undiscovered, technically recoverable resources, instead of economically recoverable?

The intent of the interagency EPCA Steering Committee—consisting of representatives of the BLM, USGS, USFS, and DOE—has been, and continues to be, to provide the Congress with the information that was requested in the EPCA statute. When the Steering Committee first met to begin discussions of implementing the requirements of Section 604 of EPCA, we were concerned by the law's wording regarding "USGS reserve estimates of oil and gas resources" and "the extent and nature of any restrictions or impediments to the development of such resources." The law's language is not consistent with USGS terminology for "reserves" and "resources." The EPCA Steering Committee interpreted the language to mean that Congress was interested in a study of both reserves and resources. To ensure that Congress understood the approach that the EPCA Steering Committee was undertaking to comply with the law, the group met with majority and minority staff of the Senate and House resource committees to describe the group's efforts.

The Steering Committee is including both proved reserves from the Energy Information Administration, and undiscovered oil and gas resources from the USGS. Providing both reserves and resources will give the Congress and the Administration the full suite of both known and potential oil and gas accumulations under Federal Lands in the study areas.

The USGS does not consider its resource assessments to be highly speculative, but the best estimates of resource potential available, ahead of exploration and drilling. USGS resource assessments have guided energy policies for several decades, and provide the BLM and Forest Service with the best information to anticipate energy industry interest for the lands that they manage.

If the EPCA study included just oil and gas reserves, then the USGS would not have had a role in the study. The resulting GIS mapping would have the locations of the few known reserves, which are under land that currently has full access, and no information about future potential land use conflicts would be available.

2. Once the identification of oil and gas resources is complete, overlays indicating where areas are closed or restricted will be superimposed. What will you do then? Will policies be adjusted to comply with President Bush's Executive Order to facilitate oil and gas development? If so, how will this occur?

The President's National Energy Policy directs the Secretary of Interior to examine and review land status and lease stipulations to Federal oil and gas leasing. In addition, the Secretary, consistent with existing laws and sound environmental practices, was directed to look for opportunities to modify them such that they foster oil and gas development and production. This is to be accomplished with full and meaningful consultation with the public, particularly with local individuals through the land use planning process and other project-specific NEPA analysis. In addition, a Presidential Executive Order directs all Federal agencies to take appropriate actions to expedite projects that will increase the production, transmission, or conservation of energy

By considering the EPCA findings in the Bureau's ongoing land use planning efforts, the Bureau will be complying with the President's directives. All information gathered as a result of the EPCA effort will be analyzed and, as appropriate, integrated into the BLM's ongoing land use planning efforts, which includes extensive opportunities for public participation and comment. The public will have the opportunity to provide specific comments on any changes that arise in the resource management plans or amendments. It should be emphasized that in no case will any recommendations made as a result of these studies preclude full compliance with statutory environmental review and protections, including the National Environmental Policy Act.

3. What changes have been made to the DOI methodology since you released the Green River Study last year? In other words, are you now factoring known reserves into the assessment?

The Green River Study was led by and released by the Department of Energy and is based on the 1999 National Petroleum Council study of natural gas in the Rocky Mountain Region. The BLM and USGS provided information and assistance for that study. The purpose of the Green River study was to examine in detail the restrictions to Federal natural gas development within the Greater Green River Basin of Wyoming and Colorado.

Unlike the Green River Study, the EPCA study focuses on both oil and natural gas; includes resources under split estate lands; and incorporates further analysis of agency experts on the impacts of various land use restrictions. Specific criteria and factors were developed by the Interagency Steering Committee for the EPCA study which are more specific to the needs of the Federal land management agencies. Some of the variations include EPCA's analysis of individual oil and gas plays, rather than allocating gas resources on a township basis, and EPCA's use of only USGS resources estimates, rather than incorporating data from non–USGS sources.

Furthermore, EPCA requires the Secretary to conduct an inventory using both oil and gas reserves and oil and gas resource estimates. The interagency EPCA Steering Committee includes the Energy Department's Energy Information Administration (EIA), which is responsible for maintaining information on oil and gas reserves for the United States. EIA's oil and gas reserve information is being incorporated into the EPCA inventory.

4. One of the criticisms of the assessment is that it is producing a biased, or skewed set of data—that the assessment will erroneously foster the misconception that there is potentially more oil and gas in areas, such as "roadless areas" that is not being developed due to access restrictions. How do you respond to this criticism?

The BLM, USGS, USFS and DOE are complying with the specific provisions of EPCA by using peer-reviewed assessment standards, all available geologic information, and statistical methods for the distribution of the undiscovered resource estimates. In addition, the interagency EPCA Steering Committee is collecting existing, publicly-available information on restrictions and impediments from the BLM's and USFS's land use management plans. It is the intention of the agencies to present this information clearly and objectively, and by using a scientific and judicious approach, to avoid misconceptions.

5. Will the assessment take State-owned, private, and split estate lands into account? If so, how?

Split estate lands—where the oil and gas mineral estate is Federally-owned regardless of surface ownership—are being included in the EPCA study. Split estate

lands are analyzed in the same manner as Federally-owned surface lands in the inventory.

As a part of the EPCA analysis, the resources are being calculated for Federal lands, as the statute requires, and for non–Federal lands as well. The non–Federal portion is displayed in the report as surface acreage and as an aggregate amount of resource for each of the five study areas so that the relative contribution of non–Federal lands within the inventory area can be compared to that of the Federal lands.

6. How will the assessment factor slant drilling capability into account?

The EPCA inventory factors in slant drilling capability by using the concept of an "extended drilling zone" (EDZ). Resources located beyond this EDZ are assumed to not be technically recoverable. The BLM and Forest Service field personnel were consulted to determine the size of the EDZ, which varies by jurisdiction. The EDZ is generally a function of the depth to the drilling objective—the deeper the objective, the larger the EDZ. The effect of the extended drilling zone in the analysis is to remove an area of land from the perimeter of areas where surface occupancy is prohibited. The width of this area removed through analytical processing is determined by Federal jurisdiction. The area removed then defaults to the access category that would otherwise apply in the absence of the no surface occupancy stipulation. The net effect is that the underlying resource is no longer considered inaccessible even though the surface cannot be occupied by drilling equipment.

Ms. CUBIN. Thank you very much. I guess I will start the questioning myself. I observed when I was reading the testimony last night of the second panel that much of it will be based on assessments by the USGS assesment in 1995, the National Petroleum Council in 1999, and Advanced Resources International Prototype EPCA study of the greater Green Basin in 2001.

Can you briefly explain the similarities and the differences between these type assessments?

Ms. CLARKE. I am going to invite Mr. Kaarlela, who has led this study, to address that question.

Mr. KAARLELA. Yes, Madam Chairman. Perhaps the best way to approach this is to just give a small historic summary of how the various studies took place. The National Petroleum Council study in 1999 was looking at natural gas, demand for natural gas in the future, and where it might come from and how it might be transported. And they looked at both domestic and non-domestic sources of natural gas, as well as looking at onshore and offshore sources within the United States.

Specific to our discussion here, they found or determined that the Rocky Mountain region of the United States was a major source of future gas for the United States onshore. When they looked at that area, they looked at basically three sample areas, and they made extrapolations with regard to what restrictions and impediments would do to that supply of natural gas, or may do to that supply of natural gas.

To have somebody do a further analysis of these areas to get a better handle of the natural gas in the areas and their specific restrictions and impediments, DOE followed up with that in 2000, and did their Green River study; again, of just natural gas. And they did a little more detailed analysis of restrictions and impediments, establishing a basic criteria or hierarchy of types of restriction, and so on.

At the same time, of course, EPCA was passed. And we began looking at what we should do. And since it appeared to us that our study under the EPCA requirement was very similar to what the

National Petroleum Council had done and DOE had done, we would use those as an example—a model, if you will—and try to improve upon it, and come up with what we would have to do.

Now, our study also, of course, by requirement of the law, includes oil; not just natural gas. So we are doing oil and natural gas. That is a major difference between the studies.

Additionally, we are required to use the U.S. Geological Survey's estimates of resources. The other studies did use some of that information, but they also combined it with other information from private sources and other sources. So we are using exclusively U.S. Geological resources estimate information.

Most of the other differences that we came up with, or a good deal of them, were a response to criticisms that came out as a result of the Department of Energy's Green River study. We tried to take those criticisms into consideration and see, where those criticisms were warranted, if we could improve upon the way that they looked at that.

And we made several corrections of those criticisms; such as there was criticism about using a sensitivity case rather than a base case, that didn't take into consideration such sensitivity factors as the ability to get to resources that may not be available directly from the surface but can be reached from directional drilling. And there were other considerations that concerned whether or not we should be considering split-estate lands, lands where the Federal Government had the sub-surface and the surface was owned by somebody else. We decided to include those in our report.

There were considerations about whether or not the extent of the area of study should be based on political boundaries, such as townships; or should it be based on actual provinces or limits of the geological basins. We decided to go with the limits of the geological basins.

Those are the main differences that we had in our study. One, ours was going to be oil and gas, not just gas; two, we were taking the Geological Survey's estimates as our main base; three, we were adding all the sensitivity factors into consideration under our study on EPCA.

Ms. CUBIN. My time has elapsed. Seeing no minority member here right now, I will yield the floor to Representative Otter for 5 minutes.

Mr. OTTER. Thank you, Madam Chairman.

And thank you to the panel for being here. Ms. Clarke, I, too, read most of the testimony that we are going to hear today in a future panel before us today. There is an assessment on the viability of the resource based upon exploration and production costs—that is, those costs getting the resource to the wellhead; infrastructure and transportation costs—those in getting it to the marketplace; potential environmental impacts. And one other additional one that came through some of the testimony would be, obviously, the economic viability has to do with the future price that the market is going to provide.

Does the agency have any scheme or any formula at which they also assess future market price? And if so, for the viability of the production and the exploration, what is that formula? And how is that assessment made? What goes into that assessment?

Ms. CLARKE. Well, we do not get into trying to assess economic viability. We feel that that is a role for the marketplace and for industry to pursue. And so what we are interested in is having good science, and making sure that data is available on technically recoverable resources.

And we feel like that is the role and responsibility that we have. We believe that then whoever is interested in pursuing the potential and the commercial value of that resource needs to do their studies and understand the markets. And certainly, those values change over time dramatically. Technology changes over time dramatically. And so I don't think it would be prudent of us to get into that business.

Mr. OTTER. I understand that. But we are talking about a public resource. And I certainly agree with that assessment. We are talking about a public resource, potentially on public lands. And because of that, we also probably need to assess—I am sure the agency does assess—the potential of success. And part of that success depends upon what the marketplace in the future is going to have for the crude oil.

And if the agency doesn't now do that—For instance, even a private landowner, if I were selling a piece of land to a potential developer, one of the things that I would want to know about is if he is going to build a supermarket there; if he or they are going to build a housing project. And if it is a housing project, is it going to be HUD housing, or is it going to be low-cost housing, or is it going to be more expensive housing?

I think one of the things that we need in order to assess the potential development of this is the economic viability; just as I may or may not sell my land to a developer, depending upon what they are going to do with it, in terms of what the economic viability is. Because I want to know that they can pay for it. And I want to know, if they mess it up, that they can clean it up. And I want to know that, if there is something that goes awry, they are prepared to stand behind it. And the economic viability of that project is going to suggest to me whether or not they are going to have the available resources to repair the damage.

Ms. CLARKE. Certainly, as we contemplate leasing, there is an onerous process that those potential lessees and permitees have to go through to demonstrate that they are capable of performance and of bonding, of mitigation, of reclamation. And in the land use process, we consider economic issues, both in the land management plans and in use authorization.

But we do not have a study process that at this time extends into that arena. It becomes part and parcel when it becomes of significance, because we are today dealing with an action or an activity. So we will have that information available, but it is not part of an ongoing study and an overall view of the world. It will become site-specific and activity-specific.

Mr. OTTER. When you are involved in the process of establishing a potential exploration and the establishment of a wellhead, does that also include the second ingredient that I talked about? And that is portability: Are we going to be able to get it from the wellhead to wherever we need to get it to, so that it can be refined or

it can be produced into value-added and usable products for the consumers? And does that include the pipeline?

So are those assessments relative to variable cost, relative to environmental cost and marketplace cost, also assessed?

Ms. CLARKE. I know that we do assessments that when someone comes forward with a plan they have to consider roads, corridors, transportation, distribution. But I don't know if it is all done in the same planning effort. Let me ask Erick to speak to that.

Mr. KAARLELA. In our planning effort, we have a process called "reasonable foreseeable development." And we don't know at that time, of course, whether or not that is what any particular operator may pursue; but we do go through and make a projection as to what we think are the types of development that will occur. And we try and figure out where the pipelines might go, where the wells might be drilled. And we use this as a basis for further consideration on the type of stipulations, type of resource conflicts, that might occur.

Again, it is kind of our best guess, because no one quite knows who is going to try what type of technique. But that is what we use right now.

Mr. OTTER. Madam Chairman, may I inquire of the Chair? We are going to have a second round?

Ms. CUBIN. You can take it right now, if you wish.

Mr. OTTER. Thank you very much, Madam Chairman.

We are talking about the Rocky Mountain West here. Would anybody on the panel be able to pinpoint for me the closest refinery to the Rocky Mountain West?

Mr. KAARLELA. I know there are refineries that are extensive throughout the West. Are you talking the closest to a particular basin or something?

Mr. OTTER. Well, no. Excuse me, maybe my question wasn't clear. You know, it is difficult to think that we would be part of setting people up for failure. And so if they are going to drill an oil well in an extremely remote place, where do we take either the gas or where do we take the oil, so that we can fracture the gas and, if it is high-sulphur gas, we can split it, take the sulphur off it, make it sweet gas, and then marketable?

And what my question goes to, if we are talking about in the Rocky Mountain West here, do we have the refinery or cracking facilities, if it is natural gas, so that we are not going to have to ship it to Mexico?

Ms. CLARKE. Right.

Mr. OTTER. That is where my question is coming from.

Ms. CLARKE. We will have to get back to you.

Mr. OTTER. OK.

Ms. CUBIN. Will the gentleman yield?

Mr. OTTER. The gentleman yields.

Ms. CUBIN. I don't know what volume you are speaking of, but certainly there are refineries in the Rocky Mountain region. There are several in Wyoming; albeit they are relatively small refineries. But there is a large refinery in Colorado.

Mr. OTTER. OK.

Ms. CUBIN. And so, yes, certainly there are refineries in the area. Again, how much of the need they will be able to fill, I can't answer

that. But, yes, there is room for some of the gas discovered to be processed.

Mr. OTTER. Thank you, Madam Chairman. I am claiming back my time.

The reason I am asking this question is because I want to revisit much of the debate that we have had about other areas of exploration. And part of that problem is, is it more economic to build a refinery, or is it more economic to build the pipeline?

And if we don't already have in place facilities large enough to handle the potential volumes, then what is the economic opportunity that we have to look at in order to enlarge a present facility, or build a new one? And so that is where my question goes to.

And I would hope in some of these assessments on economic viability that we would put in an equation that basically speaks to the question of: How do we get the resource out of the ground and into marketable products?

Ms. CLARKE. Right.

Mr. OTTER. I thank you, Madam Chairman.

Ms. CUBIN. I thank you, too, Madam Secretary.

Ms. CLARKE. Thank you.

Ms. CUBIN. And we really appreciate your time here. I am sure that some of the members who are not here will have more questions for you later on. So if they will submit them to you in the next—what, 4 days? Ten days.

Ms. CLARKE. OK.

Ms. CUBIN. We would appreciate a response. And we thank you very much for your testimony.

Ms. CLARKE. Thank you.

Ms. CUBIN. And we look forward to seeing you much more frequently. And I am sure it will be a good interchange.

Ms. CLARKE. Thank you very much.

Ms. CUBIN. Thank you.

The next panel to come forward will be Debra Knopman, Ph.D., Senior Engineer and Associate Director of RAND Research and Development, Science and Technology; Charles Mankin, Ph.D., State Geologist of Oklahoma, testifying on behalf of American Association of Petroleum Geologists; Peter Morton, Ph.D., Resource Economist, The Wilderness Society; Ray Seegmiller, Chairman, President, and Chief Executive Officer, testifying on behalf of Cabot Oil and Gas Corporation, and the Domestic Petroleum Council.

I see you are finding your way to the table. If we are ready to begin now the second panel, the Chairman now recognizes Dr. Knopman to testify for 5 minutes. The timing lights are on, on the table, and they will indicate when your testimony should come to a conclusion. All witness statements will be submitted for the hearing record. Thank you.

So at this time, I would like to call on Ms. Knopman to testify.

Ms. KNOPMAN. It is "Dr. Knopman." Thank you, Madam Chairman, for the opportunity to testify.

Ms. CUBIN. Excuse me. Doctor. Excuse me.

Ms. KNOPMAN. No problem.

STATEMENT OF DEBRA KNOPMAN, PH.D., ASSOCIATE DIRECTOR, RAND SCIENCE AND TECHNOLOGY

Ms. KNOPMAN. Thank you, Madam Chairman, for the opportunity to testify before your Subcommittee about methods of assessing oil and gas resources. I am a senior engineer at RAND, and also a member of the study team for RAND's recently released interim report on "Assessing Gas and Oil Resources in the Intermountain West," as well as a related summary paper.

These publications are interim products from a project that we expect to complete this summer. Research, as has been noted by you, is funded by the William and Flora Hewlett Foundation.

Here with me today are two of my RAND co-authors, Dr. Mark Bernstein and Dr. Tom LaTourette. I would also like to note at this time that the views expressed here are my own and do not, nor should they be taken to reflect those of either RAND or any sponsors of its research.

RAND does not have an institutional position on whether oil and gas exploration and production should proceed on currently restricted Federal lands. This is a complex policy question with several competing considerations, including the nation's need for long-term, reliable, and clean energy supplies. Rather, our interest is in the quality, relevance, and transparency of technical information that surrounds the public debate on future development.

We are also interested in encouraging a broader discussion about constraints on exploration and production beyond that of access restrictions applied to Federal lands. We believe that such a discussion would contribute significantly to the debate on national energy and land management policies.

Our main point can be summarized as follows: The debate over access to gas and oil resources on Federally managed lands in the Intermountain West would benefit from an improved understanding of how much resource might actually be developed, and at what cost.

Our study recommends developing and publicly reporting estimates of viable resources in the region—Federal and non-Federal lands—using a step-wise approach that incorporates a set of economic and environmental criteria. These criteria include exploration and production costs, infrastructure and transportation costs, and environmental impacts. We also recommend ways in which the ongoing BLM basin-specific studies of the impact of access restrictions could be further enhanced.

A broader framing of the debate about available oil and gas resources is important for two primary reasons. First, most states and regions are in the process of planning for substantial future dependence on natural gas as their dominant electricity generating fuel. Given this, decisionmakers and the public would benefit from a more comprehensive view of prospective costs and availability of long-term domestic supplies.

Second, it makes sense to focus public debate about access to Federal lands on those resources that are most likely to be actually produced, in light of economic and environmental considerations.

There are legitimate questions about the appropriate Federal role in examining the economics of exploration and development scenarios. Our proposed approach is not meant to replace indus-

try's detailed economic evaluations at the play level, or replace Federal land managers' existing environmental assessment and permitting processes. Rather, it is meant to provide decisionmakers with a more comprehensive assessment of bounding ranges of resource viability at the regional and sub-regional scale.

We think that our proposed methodology would enhance current efforts by BLM and other Federal land managers to communicate more effectively and clearly the economic and environmental implications of their actions. We are simply arguing for more comprehensive information in the policy process.

RAND's interest in this issue, as it is in all of our work, is to improve decisionmaking through research and analysis. We are an independent, non-profit organization, dedicated to producing objective, non-partisan analysis. Our publications are subjected to rigorous peer review and quality assurance, in which we actively seek internal and outside experts to critique our work. The research upon which this testimony is based has been through this quality assurance process.

We are currently preparing to produce a more comprehensive assessment methodology of the viable resource, as well as an application of this methodology to basins in the West. Given the challenge of developing such methodology, as well as its relevance to the current debate on energy policy, we believe that it was important to release this interim report at this time. With the publication of this report, we seek additional feedback on our proposed methodology as we proceed with our next phase of work.

This concludes my testimony. I would like the full written statement to be included in the record. And I welcome any questions you may have. Thank you.

[The prepared statement of Ms. Knopman follows:]

Statement of Debra Knopman, Associate Director of RAND Science & Technology

Thank you, Madam Chairman, for the opportunity to testify before the Subcommittee on Energy and Mineral Resources about methods of assessing oil and gas resources. At this time, I ask that my full written statement be entered into the record.

I am a Senior Engineer at RAND and a member of the study team for RAND's just released interim report "Assessing Gas and Oil Resources in the Intermountain West: Review of Methods and Framework for a New Approach" and for an abridged version of that work in a paper entitled "A New Approach to Assessing Gas and Oil Resources in the Intermountain West." These publications are interim products of a study that we expect to complete this summer. The research is funded by the William and Flora Hewlett Foundation. Here with me today are two of my RAND co-authors on those publications, Dr. Tom LaTourrette and Dr. Mark Bernstein.

We are at approximately the midpoint of our study. We have completed the following tasks:

- A review of existing resource assessment methodologies and results
- An evaluation of recent studies of Federal lands access restrictions in the Intermountain West
- Consideration of a set of criteria that can be used to define the "viable" hydrocarbon resource, with particular attention to issues relevant to the Intermountain West

We still plan to more fully address the development of a comprehensive assessment methodology for the viable resource, and then apply this methodology to Intermountain West basins.

Given the challenge of developing such a methodology, as well as its relevance to the current debate on energy policy, we believe that it was important to release this interim report at this time. By doing so, we have created the opportunity to gather

additional feedback on our proposed methodology as we proceed with the next phase of work.

RAND's interest in this issue, as it is in all our work, is to improve decision-making through research and analysis. We are an independent non-profit organization, dedicated to producing objective, non-partisan analysis. Our publications are subjected to rigorous peer review and quality assurance in which we actively seek internal and outside experts to critique our work. The research upon which this testimony is based has been through this quality assurance process.

Let me introduce a summary of our work to date by saying that RAND does not have a position on whether oil and gas exploration and development should proceed on currently restricted Federally managed lands. This is a complex policy question with several competing considerations, including the nation's need for long-term, reliable, and clean energy supplies. Rather, our interest is in the quality, relevance, and transparency of the technical information that surrounds the public debate on future development. We are also interested in encouraging a broader discussion about constraints on exploration and development beyond that of access restrictions applied to Federal lands. We believe that improved public understanding of the range of estimated costs and impacts of development and associated infrastructure, under different technology and economic assumptions, will contribute significantly to debate on national energy and land management policies.

Our main point can be summarized as follows: The debate over access to gas and oil resources on Federally managed lands in the Intermountain West would benefit from an improved understanding of how much resource might actually be developed and at what costs. Our study recommends developing and publicly reporting estimates of "viable" resources in the region, using a step-wise approach that incorporates a set of economic and environmental criteria. We also recommend ways in which the Bureau of Land Management's (BLM's) on-going basin-specific studies on the impact of access restrictions could be further enhanced.

A broader framing of the debate about potential development of oil and gas resources is important for two primary reasons. First, most states and regions are in the process of planning for substantial future dependence on natural gas as their dominant electricity-generating fuel. Given this, decisionmakers and the public would benefit from a more comprehensive view of prospective costs and availability of long-term domestic supplies of natural gas and oil. Second, it makes sense for Federal land managers, as well as Congress and the public, to focus concerns about access restrictions on those resources that are prime candidates for production given economic viability and environmental considerations.

SOME POLICY QUESTIONS REQUIRE MORE INFORMATION THAN WHAT TRADITIONAL ASSESSMENTS PROVIDE

The goal of traditional resource assessments is to estimate the nation's potential supply of natural gas and oil resources. As part of our research, we examined four recent assessments: the U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995; Minerals Management Service, 2000; National Petroleum Council, 1999; and Potential Gas Committee, 2001. [1] Although the assessments vary, they agree that the Intermountain West contains substantial natural gas and oil resources.

These assessments estimate what is called the "technically recoverable" resource [2]—the amount of the resource that is estimated to be recoverable given certain assumptions about exploration and production capabilities. Resources are evaluated in terms of geological criteria and technical feasibility of recovery, but without economic or other considerations. These estimates, therefore, are not intended to indicate how much resource will likely be developed and at what cost.

An enhancement to these assessments would be a range of estimates of the resource that can be "viably produced," under varying assumptions about future energy prices, exploration scenarios, and current and emerging development technologies. Determining the oil and gas resources that are viable to produce depends

[1] The four assessments are as follows: U.S. Geological Survey National Oil and Gas Resource Assessment Team, 1995 National Assessment of United States Oil and Gas Resources, U.S. Geological Survey Circular 1118, 1995; Minerals Management Service, Outer Continental Shelf Petroleum Assessment, 2000, U.S. Minerals Management Service, 2000; National Petroleum Council, Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand, National Petroleum Council, 1999; and Potential Gas Committee, Potential Supply of Natural Gas in the United States, Potential Gas Agency, Golden, CO, 2001.

[2] In practice, the definition of the term "technically recoverable" is unclear and is inconsistently applied among the different assessments. A large part of the difference between existing resource assessments results from differing assumptions as to what constitutes a technically recoverable resource.

on three main factors: (1) exploration and production costs (those costs incurred in getting the resource to the wellhead); (2) infrastructure and transportation costs (those costs incurred in getting the resource to the market); and (3) potential environmental impacts.

It is important to note at this point that we highly value these existing expert resource assessments, and that we are in no way suggesting that they are inadequate for their intended purpose. Indeed, our proposed methodology builds on them. We are simply saying that more comprehensive estimates of resources likely to be developed would better focus policy discussion on key policy questions, such as, for example, the projected adequacy of supply and future cost of natural gas; and the overall effectiveness or hindrance of access restrictions in meeting future energy demand with adequate environmental safeguards.

PROPOSED METHODOLOGY TO ESTIMATE THE VIABLE RESOURCE

Our proposed methodology is designed to generate a series of map views of resources favorable for development under varying assumptions about energy prices, technology, and environmental impacts. A resource would be economically viable if the revenue expected from the developed resource is likely to exceed the costs of exploration, production, infrastructure, and transportation. Environmental impacts are difficult to predict. We intend to devise measures of existing environmental conditions and examine implications of change in those conditions. We will classify areas based on a selected set of water quality, air quality, and ecological measures, and relate these measures to existing environmental standards.

We believe that one useful perspective is to look at these factors sequentially, beginning with the economic criteria. If the costs of getting resources from the wellhead to market would preclude development under some set of assumptions, then environmental considerations would not come into play.

Similarly, the extent and need for various access restrictions on Federal lands can be viewed in the context of economic viability. Indeed, industry uses this same process of assessing the viability of developing oil and gas resources, whether on Federal or non-federal lands. Industry would be unlikely to pursue development if the costs of getting the resource out of the ground and to market exceeded revenue projections, or potential environmental concerns were viewed as significant and likely to be contentious. In essence, our proposed methodology would more systematically bring to the public discussion the multiple factors, including economic costs and environmental impacts, that industry must address before making a decision to move forward with development on public lands.

BUILDING A COMPREHENSIVE RESOURCE ASSESSMENT METHODOLOGY

The three factors cited above—exploration and production costs, infrastructure and transportation costs, and environmental impacts—reflect well-known and often cited issues that determine the availability of gas and oil resources. Aspects of these issues have been addressed to varying degrees in previous studies.[3] However, the factors are generally not all considered in resource assessment methodologies. Building a comprehensive methodology that does so to the public's benefit is challenging.

RAND intends to develop an assessment tool that would produce ranges of estimates of resources that account for uncertainties. This tool would allow decisionmakers to vary assumptions about costs and constraints at each step of the analysis, improve understanding of the sensitivity of results to those assumptions, and determine the value of reducing data uncertainties within the analysis. For example, should the Federal Government increase investments to enhance existing assessments of the technically recoverable resource? How dependent are the results on assumptions about technological change? These are important questions to ask (and answer) for decisionmakers faced with reducing risks in long-term energy contracts or land managers faced with multiple choices about changing access restrictions.

Exploration and Production Costs

Estimating economic viability involves balancing exploration and production costs with resource revenues to determine if it would be economically logical to proceed with production.[4] Such costs, commonly referred to as "wellhead" costs, include ex-

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[3] See, for example, Harry E. Vidas, Robert H. Hugman, and David S. Haverkamp, Guide to the Hydrocarbon Supply Model: 1993 Update, Gas Research Institute, Report GRI–93/0454, 1993; Emil D. Attanasi, Economics and the 1995 Assessment of United States Oil and Gas Resources, U.S. Geological Survey Circular 1145, 1998; and National Petroleum Council, Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand, National Petroleum Council, 1999.

[4] Harry E. Vidas, Robert H. Hugman, and David S. Haverkamp, Guide to the Hydrocarbon Supply Model: 1993 Update, Gas Research Institute, Report GRI–93/0454, 1993; and Emil D.

ploration and development drilling, well completion, lease equipment, operations and maintenance, taxes and royalties; return on investment would also be included in this category.

Estimates of economic recoverability in the Rocky Mountain Region are inherently uncertain and are hence best represented as a range of estimates rather than as a single point estimate. However, by way of illustration, a 1998 U.S. Geological Survey study indicated that, at a regional scale, significant amounts of gas and oil resources may not be economically viable for production in the foreseeable future. The USGS results (using 1994 data) showed that adding economic viability alone would rule out, in the near term, the recovery of a large fraction of the gas resource that would otherwise be deemed technically recoverable from the Green River Basin.[5] Of course, it is important to note that technological improvements and changing economic conditions have altered these estimates over time, particularly regarding the costs of developing nonconventional resources. Technology in this area is progressing rapidly, and the economically recoverable fractions are likely to be higher today than those reported in the USGS study.

Industry assessments of wellhead costs are tailored to reflect the unique costs of gas and oil exploration and production in the Intermountain West. We propose that a comprehensive assessment of the viable resource in the public domain reflect these differential costs. Further, a comprehensive assessment should account for differential costs resulting from the high abundance of nonconventional gas in the Rockies[6]; well completion, lease equipment, and operating costs can be higher for low-permeability (tight) sandstone and coalbed methane deposits. It is also important to use, whenever available, local drilling success ratios, rather than regional averages of existing wells, since using ratios from existing wells biases assessments toward conventional deposits. Finally, other unique factors need to be addressed, including the steep and rugged terrain, remote locations, low-quality gas, and shallow formations.

Infrastructure Costs

Turning now to infrastructure costs, much of the economically viable resources in the Intermountain West cannot be developed without constructing additional pipeline and road infrastructure. Again, these are costs that industry knows well. We propose that a comprehensive assessment in the public domain reflect estimates of these costs as well. Capital expenditures and operating costs for infrastructure, in general, are comparatively high in the Rocky Mountain Region because of less existing infrastructure relative to other regions. If required, new infrastructure could add substantial costs beyond the wellhead costs alone.

As was true in assessing wellhead costs, some complicating factors need to be considered in assessing infrastructure costs in the Rocky Mountain Region. These include the remoteness of existing pipeline infrastructure, particularly transmission pipelines; the rough terrain, unstable soil, and icing in colder climates; the extensive water disposal requirements associated with coalbed methane deposits; and the potential need for compressor capability to transport low-pressure gas from nonconventional deposits. In addition, produced water and other wastes may need to be removed from the site, in some cases requiring additional pipeline capacity.

Environmental Impact

Finally, we believe that there is value in looking more specifically, within the context of existing laws, at varying levels of change in existing environmental conditions that could occur as a consequence of exploration and development. We will likely use individual indicators to track a spectrum of conditions, including air quality, water quality, soil properties, hazardous materials, protected species, migration patterns, vegetation habitats, and land use. These conditions can be categorized and mapped to enable decisionmakers to understand the spatial distribution of existing

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Attanasi, Economics and the 1995 Assessment of United States Oil and Gas Resources, U.S. Geological Survey Circular 1145, 1998.

[5] Emil D. Attanasi, Economics and the 1995 Assessment of United States Oil and Gas Resources, U.S. Geological Survey Circular 1145, 1998. The U.S. Geological Survey economic assessment accounts for current technology only. As a result, its economic assessment is generally considered to be more conservative than the assessments used by industry. The data and forecasting assumptions used in the USGS study are current as of about 1994. It is important to note that technological improvements and changing economic conditions will alter these estimates over time. The use of more current recoverable resource estimates and cost assumptions will undoubtedly alter the results, particularly regarding the costs of developing nonconventional resources. Technology in this area is progressing rapidly, and the economically recoverable fractions are likely to be higher today than reported in the USGS study.

[6] Nonconventional resources include low-permeability (tight) sandstone, shale, chalk, and coalbed methane.

environmental conditions within a total resource area. We do not intend to predict environmental impacts, but instead, we intend to show how varying environmental conditions relative to existing environmental standards could affect estimates of the viable resource.

It is, again, important to note that RAND has not performed a comprehensive assessment of any area yet. We have focused the first phase of our work on developing a framework that would guide such an assessment. [7]

CONCLUDING THOUGHTS

Assumptions about the viability of resources—inherently uncertain under any method—need to be carefully examined for either excessive conservatism or optimism. A guiding principle of sound analysis is that there be consistency in whatever kinds of assumptions are used in assessment studies. For example, assessments that mix overly conservative assumptions about, say, drilling technologies with overly optimistic assumptions about wellhead costs or infrastructure economics are not useful for policymaking. In the context of understanding future domestic energy supply scenarios, consistency needs to further extend beyond a limited focus on selected Federal lands and toward a broader view of assessment on all lands.

There are legitimate questions about the appropriate Federal role in examining the economics of exploration and development scenarios. Our proposed approach is not meant to replace industry's detailed, site-specific economic evaluations or Federal land managers' existing environmental assessment and permitting processes. Rather, it is meant to provide decisionmakers with a more comprehensive assessment of bounding ranges of resource viability at the regional and subregional scale. We believe our proposed methodology would enhance current efforts by the BLM and other Federal land managers to communicate more effectively and clearly the economics and environmental implications of their actions. We are simply arguing for more comprehensive information in the policy process.

This concludes my testimony. I welcome any questions you may have. Thank you.

[NOTE: The report "Assessing Gas and Oil Resources in the Intermountain West: Review of Methods and Framework for a New Approach" submitted for the record has been retained in the Committee's official files.]

[Responses to questions submitted for the record by Ms. Knopman follow:]

MAY 6, 2002

Honorable Barbara Cubin, Chairman
Subcommittee on Energy and Mineral Resources
Committee on Resources
U.S. House of Representatives
Washington, DC 20515

Dear Madam Chairman:

This letter is in response to your request of April 23, 2002. In the enclosed attachment, I have provided written answers to your nine questions related to my testimony on April 18th. Please let me know if I may provide you with any additional information.

I appreciated the opportunity to testify before your Subcommittee and look forward to working with you and your staff in the future.

Sincerely,

Debra S. Knopman
Associate Director
RAND Science & Technology

Enclosure

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[7] RAND will begin this effort by analyzing the Green River Basin. The analysis will specify the relationships among gas and oil deposits, technological options, economic costs, infrastructure requirements, environmental sensitivities, and other variables to allow for a comprehensive assessment of the viable gas and oil resource.

ATTACHMENT

Questions from Chairman Cubin

1. Did RAND ask the AAPG Committee on Resource Assessment for a peer review of its study? Did RAND ask anyone with extensive experience in studying and finding oil and gas deposits to peer review their study?

As I discussed in my testimony, our report "Assessing Gas and Oil Resources in the Intermountain West: Review of Methods and Framework for a New Approach" and an abridged version of that work "A New Approach to Assessing Gas and Oil Resources in the Intermountain West" are interim products of a study that we expect to complete this summer. We are at approximately the midpoint of our study. We have completed the following tasks:

- A review of existing resource assessment methodologies and results
- An evaluation of recent studies of federal lands access restrictions in the Intermountain West
- Consideration of a set of criteria that can be used to define the "viable" hydrocarbon resource, with particular attention to issues relevant to the Intermountain West

We still plan to more fully address the development of a comprehensive assessment methodology for the viable resource, and then apply this methodology to Intermountain West basins. In releasing the interim report, we sought to gather additional feedback on our proposed methodology as we proceed with the next phase of work.

RAND asked several natural gas resource experts to review the interim report prior to its release. These experts included Harry Vidas and Robert Hugman of Energy and Environmental Analysis, Inc (EEA). Mr. Vidas and Mr. Hugman are acknowledged experts in technical and economic assessments of gas and oil resources and have extensive gas and oil industry experience. EEA was the lead consultant on the 1999 National Petroleum Council (NPC) natural gas study. Mr. Vidas was the EEA contact for the supply subgroup on that study. Mr. Vidas was also a member of the Economic Assumptions & Policy and Technology Subgroups for the study. Because of their knowledge and expertise in these areas, Mr. Vidas and Mr. Hugman will be working with us as subcontractors as we develop our economic evaluations in the next phase of this study.

RAND did not ask AAPG to review the interim report prior to its release, but we look forward to opening a dialog with AAPG and industry representatives as we move forward on the next phase of our work. We look forward to maintaining contact with industry, government, and other experts through the next phase of this project to provide us with the best available information relevant to the development and implementation of our methodology.

2. Ms. Knopman, in your testimony, you spend a great deal of time discussion how you will use resource estimates to develop "viable resource" estimates, but you fail to mention what you are going to use for your Resource Base. Will you be developing your own resource estimates or whose resource estimates will you be using?

RAND will analyze separate cases using the 1995 U.S. Geological Survey (USGS) resource base (including any subsequent revisions that have been released) and the 1999 National Petroleum Council study natural gas resource base.

3. RAND states that their analysis of oil and gas resources will include a number of detailed economic factors that are actually more characteristic of a feasibility study where a lot more detailed data is [sic] available. How do you propose to determine these factors in an assessment of a region where most of the resource has not even been found—much less developed?

Data is limited even under the best of circumstances when assessing oil and gas resources. Many of the existing assessments are done by extrapolation to like fields in other parts of the country. Further, where such data are not available, the assessments adopt assumptions based on judgement as do oil and gas producing companies when evaluating an individual property. This type of uncertainty is always present. Nevertheless, a significant amount of the resource is already being explored and developed. Technical information necessary to estimate wellhead economics and infrastructure requirements is available for tight sand, coalbed methane and conventional deposits in the Greater Green River Basin and other basins. Our intent is to use the best data available to provide the most information for policy analysis. Where data are not available, we will indicate that deficiency and represent the uncertainty in the analysis accordingly.

4. You state in your written testimony, "We will likely use individual indicators to track a spectrum of conditions, including air quality, water quality, soil properties, hazardous materials, protected species, migration patterns, vegetation habitats, and land use." You will then categorize and map those factors to enable decision makers to understand the [sic] spacial distribution of existing conditions within a resource area. Isn't this a duplication of the [sic] spacial resource data already in use by the BLM and Forest Service for making informed land use decisions? Also, as a follow up, how will you handle oil and gas leasing stipulations?

RAND's approach will not duplicate data collection efforts by the Bureau of Land Management (BLM) and Forest Service or their application to specific parcel-scale land use decisions. The environmental indicators we intend to develop will be at the regional to subregional scale and used in conjunction with the similarly scaled wellhead and infrastructure cost data to improve understanding of the distribution of viable resources in the Intermountain West. These indicators are intended for use earlier in the decisionmaking process than the BLM and Forest Service environmental data and analysis, and meant to be used in conjunction with similarly scaled economic viability criteria.

5. How do you factor the temporal aspect into your "viable resource" estimate, for example in 1995 the USGS estimated that Wyoming's Powder River Basin contained a mean technically recoverable CBM resource of 1.11 trillion cubic feet of gas, however their current estimate is 14.26 Tcf, and an even more recent estimate by the Wyoming Geological Survey is 25 Tcf?

As you point out, technically recoverable resource assessments are highly uncertain, and as more information becomes available, often turn out to be inaccurate in retrospect. The case of coalbed methane in the Powder River Basin, which you cite, is a good example. The USGS and others who assess the technically recoverable resource do not claim that their estimates reflect the "total" or "entire" resource base. Nor would we make that claim with regard to viable resource estimates. Because of the way in which they are defined, technically recoverable resource estimates exclude significant amounts of known resources (such as coalbed methane in the past and methane hydrates now). The amount and type of resources included in technically recoverable resource assessments changes with time as information and technology improves.

Similarly, economically recoverable resource estimates are also subject to uncertainties and consequent changes over time. These estimates involve additional assumptions that add to uncertainty, but the bulk of the uncertainty is geological and is inherent in all resource assessments. Robust resource assessment methodologies should have a means of reflecting these uncertainties. They should further be updated with sufficient frequency to capture new information. Our intention is to present estimates of the viable resource in terms of a range and not a single estimate. The range will reflect existing uncertainty in technical and economic information. We also intend to estimate price-development curves that will indicate how estimates of the viable resource might change as prices changes. Further, the approach we are proposing is not intended to be completed as a one-time study providing the "final" answer, but will need to be updated periodically like other resource assessments.

6. Can you explain Figure 1, Page 2 of the February 2002 RAND interim report to me? In the text you refer to the technically recoverable resources shown as a straight line in your graph as the "available resource." Are you implying that the technically recoverable resource is the amount that can ultimately be recovered at a 100 percent recovery rate? Doesn't the technically recoverable resource also change, often significantly, as companies learn more about a producing area? Also, isn't the technically recoverable resource influenced to some extent by market price?

Our discussion of Figure 1 refers to the effect of the viability criteria on the amount of resource that is likely to be recovered. It would have been clearer to refer to the "recoverable" rather than "available" resource.

We intend to use the technically recoverable resource as our base estimate. As defined by the USGS, the technically recoverable resource is a function of current technology but not a function of market price. Their definition implies that if economics were not a factor, all of the technically recoverable resource could be physically extracted given today's technology. We use that definition in our display of information in Figure 1.

7. Can RAND support the conclusion that regional assessments overestimate oil and gas resources? Can they cite some examples that illustrate that this is a problem?

We do not say that technically recoverable resource assessments overestimate oil and gas resources in the ground. We believe that the USGS estimates are technically sound and intend to use them as a starting point for our own analysis. Rather, our primary conclusion is that technically recoverable resource estimates do not represent the amount of gas or oil that is likely to be recovered in the foreseeable future. In fact, the USGS, Potential Gas Committee, and NPC assessments all agree with this point. Our work is aimed at developing a methodology to estimate this latter quantity, which we call the viable resource. This is not a new conclusion, but rather an observation that the definition of technically recoverable resources excludes explicit consideration of economic factors. We think those factors are important considerations for policymakers and other users of publicly managed lands.

A second conclusion in our work to date relates to access restriction studies. In Figures 3.1 and 3.2 in Chapter 3 of our interim report, we show how excluding proved reserves and resources under non-federal lands leads to a larger fraction of resources subject to access restrictions than would be the case if all resources were included in the calculation. While this is a matter of arithmetic, it is also a matter of policy as to what the appropriate resource base should be to estimate the impact of any constraint on development, including state and federal access restrictions.

8. RAND's study so far has been funded by a $450,000 grant from the Hewlett Foundation. Has RAND received any additional grants from either the Hewlett or the Energy Foundation for work on oil and gas assessments in the United States?

At this time, RAND has no other funding from any foundation for work on oil and gas assessments. We have requested but not yet received supplemental funds from the Hewlett Foundation to cover additional costs associated with the hearing and interim report.

9. Which is more sensitive to long-term change and short-term periodic fluctuation, a regional assessment of oil and gas resources or the economic evaluation of the resource predicted from a regional assessment?

We do not intend to forecast future economic conditions, but rather intend to show how the range of the estimated viable resource might change as economic conditions change. In working with ranges of estimates rather than point estimates, we will be communicating the temporal and spatial uncertainty in both resource estimates and economic conditions. The uncertainty of regional assessments of oil and gas resources has already been noted in the Chairman's 5th question and in our response. Short-term fluctuations in energy prices are well known although the long-term price trend has been relatively stable.

Ms. CUBIN. Thank you very much, Doctor.

The next person to be recognized for their 5-minute testimony is Charles J. Mankin, Ph.D.

STATEMENT OF CHARLES J. MANKIN, PH.D., STATE GEOLOGIST OF OKLAHOMA, AND SECRETARY, AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS

Mr. MANKIN. Thank you, Madam Chairman, for the opportunity to participate in this important hearing. I am Charles Mankin, director of the Oklahoma Geological Survey, and Director of Sarkey Energy Center at the University of Oklahoma. Today I am speaking on behalf of the American Association of Petroleum Geologists, an international professional society of 30,000 members, for which I serve as secretary of the Executive Committee.

The AAPG Committee on Resource Evaluation was chartered by the Executive Committee of AAPG in 1993 in response to a recommendation from a National Research Council committee that reviewed an earlier—I believe 1989—assessment of petroleum resources in the United States by the U.S. Geological Survey.

That study, which I chaired, recommended that the USGS seek external professional expertise and data on sedimentary basins in

the U.S. The CORE committee was thus established to accomplish that objective. I want to thank the members of the CORE committee for their efforts in assisting me in developing this testimony.

For the record, I would like to define that part of the resource spectrum that we are concerned with today. The chart on our left shows a range of resources from reserves from which we derive our current production, the resources that through time and effort will be converted to reserves. Our focus today is on that prospective part of the resources that is highlighted in red.

Ms. CUBIN. Would the gentleman yield? Since there aren't very many people here today, could we just have that moved up where we can see it well?

[Pause.]

Ms. CUBIN. Is that as close as it can come? Then we can see the people, too. Thank you. OK, that is good.

Mr. MANKIN. Studies by the U.S. Geological Survey and the National Petroleum Council have concluded that the most prospective areas of the U.S. for major new discoveries, especially for natural gas, are the Rocky Mountain sedimentary basins, the offshore of the Gulf of Mexico, the Atlantic and Pacific outer continental shelves, and the North Slope of Alaska. Currently, the Atlantic, Pacific, and eastern Gulf are restricted from mineral exploration. I suspect that the debate over the North Slope may well be going on as we meet. In addition, portions of the Rocky Mountain region are restricted or closed, as illustrated in that second chart that was just taken down.

While others have and are proposing that the process be changed from the identification of technically recovered resources to a category that would include economic content, the AAPG maintains the firm belief that technically recoverable resources is the correct base to use when making policy decisions on competing use of Federal lands.

Incorporating an economic overprint, when few of the economic factors can be determined with any degree of accuracy, simply increases the uncertainty in the magnitude of the resource base, and it diminishes the mean value. That is simply a mathematical calculation.

Although further analysis of this resource base is perfectly justified, depending upon policy issues to be addressed, only the total resource base can be used to balance against other competing social environmental uses or the preservation of these lands.

The United States has abundant energy resources. However, we are now faced with a real energy crisis, because the Nation has not developed and implemented a comprehensive energy policy. In order to ensure that our way of life is not dramatically impacted because of energy shortages, AAPG recommends the following:

The U.S. must develop a national energy policy that provides dependable, affordable, and uninterruptible energy for public and commerce, and is based on a sound scientific assessment of the nation's resources and reserves.

Energy policy must address the needs of all stakeholders, especially the consumers, and not over-react to the demands of the shrillest interest with the most money for publicizing a particular position.

Energy policy must be strategic and long-term; not quick fixes, as in short-term crises.

Energy policy must include a role for all energy resources, including coal and nuclear.

Resource assessments are a vital planning tool for policymakers and industry; the agencies that perform these assessments and track oil and gas resources and reserves need continued support; they have done a good job to date.

A major long-term and capital-intensive industry effort is required to explore for, develop, produce, and build the infrastructure necessary to deliver the energy supplies required to meet projected demand; energy policy must facilitate processes that attract capital investment in energy development, without creating costly and time-consuming regulatory roadblocks.

Industry access to public lands which might contain hydrocarbon resources should be a priority to encourage domestic energy sources; we cannot become further and more dangerously dependent on unreliable foreign imports.

The public must be assured that energy resource development can be accomplished in an environmentally sensitive manner; the technology is available to do this, and the petroleum industry is already practicing such environmental responsibility.

On behalf of the AAPG, I thank the Subcommittee for giving us this opportunity to testify.

[The prepared statement of Mr. Mankin follows:]

Statement of Charles J. Mankin, Ph.D., Director, Oklahoma Geological Survey, and Director, Sarkey Energy Institute, University of Oklahoma, Norman, Oklahoma, and Secretary, American Association of Petroleum Geologists, Tulsa, Oklahoma

As a representative of the 30,000-member American Association of Petroleum Geologists (AAPG), I have been invited here today to testify as to the data, methods and technology on which hydrocarbon resource assessments for policy decisions should be conducted.

AAPG was honored to be invited last year by this Subcommittee to comment on the oil and gas resource estimates conducted by the United States Geological Survey (USGS) and Minerals Management Service (MMS). At that hearing we testified that these agencies have used available geological data, have applied sound scientific principles and have done a good job in assessing the undiscovered hydrocarbon resources in the United States. Although we did not take a public position on the 1999 National Petroleum Council's report entitled "Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand", detailing the gas resources within the United States that are not accessible to meet the nation's needs, we agreed with its methods and conclusions. Today, I would like to repeat our appraisal of the methodologies used by USGS, MMS, and NPC and would also like to state in the very beginning that we are unable to say the same about some other methodologies being proposed, such as that proposed in the Rand Issue Paper.

Assessment of a resource is a time-dynamic process. Because this process involves estimating the location and magnitude of an inherently unknown quantity, the accuracy of an assessment may be considered to be limited by 1) the perception and understanding of the origin and occurrence of the resource, 2) the quality, distribution and accessibility of available data from which to project estimates, and 3) the methods employed to conduct the assessment. Whereas USGS, MMS, and NPC studies have addressed all of these issues, the RAND Issue Paper does not offer any insight into the above three points.

AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS

The American Association of Petroleum Geologists was founded in 1917. It is the largest professional geological society in the United States, and has members worldwide. The membership is dedicated to the geological study of the earth and it's environment, and the exploration and development of hydrocarbon resources and other

energy minerals. Because much of the membership is engaged, either directly or indirectly, in the search for hydrocarbons and the economic development of hydrocarbon deposits, the AAPG is keenly interested in understanding the amount and geographic distribution of hydrocarbon reserves and resources. AAPG advocates a comprehensive national energy policy based on sound science and knowledge of the nation's resources and reserves.

COMMITTEE ON RESOURCE EVALUATION

In 1993, the AAPG Executive Committee chartered the Committee on Resource Evaluation (CORE) to "provide input and facilitate U.S. Government agencies in performing assessments of U.S. hydrocarbon resources." The charter was amended in 1997 to include international assessments so CORE would have a worldwide view of hydrocarbon resources. Since inception, CORE has reviewed the methodologies and scientific methods used for assessments by the U.S. Geological Survey (USGS) and the Minerals Management Service (MMS), and, in several instances, has made individual AAPG members with specific knowledge of certain geological provinces available to the agencies. To a lesser degree, CORE has offered opinions and technical information to the Energy Information Administration (EIA). For example, CORE supplied feedback to the EIA regarding it's study of the economic impacts of the Kyoto Protocol on U.S. energy markets and made members with Deepwater Gulf of Mexico knowledge available to the EIA for consultation.

The Committee membership consists of domestic and international managers of major petroleum companies, independent geologists and environmental consultants, two current and former state geologists, three past AAPG Presidents, Director of the Potential Gas Committee (Colorado School of Mines), and scientists from the USGS and MMS. All the members have a great deal of expertise in the science and technology of reserve and resource estimation. At most of its meetings, CORE has invited guests from the USGS, MMS, EIA and industry and environmental experts who can contribute to our knowledge of the nature, amount, and geographic distribution of known, and yet to be discovered resources. CORE does not restrict its interest to conventional hydrocarbons, but includes basin-centered gas in continuous reservoirs, coal bed methane, shale gas, and to some level, gas hydrates.

Since its formation, CORE has consulted with the USGS on its 1995 National Assessment of United States Oil and Gas Resources, the 1999 Arctic National Wildlife Refuge 1002 Area assessment, and the 2000 World Petroleum Assessment, and the currently ongoing assessment of unconventional gas accumulations. For all of these, the Committee on Resource Evaluation has recommended to the AAPG Executive Committee that AAPG endorse the scientific methodologies and techniques used by the USGS, and the AAPG has publicly done so. AAPG has not endorsed specific resource numbers generated by the assessments, but has endorsed the sound scientific process used to generate the probability distributions that characterize these resources. As mentioned earlier, the then–Vice Chair and current Chair of the Committee on Resource Assessment, Dr. Naresh Kumar, testified in front of this Subcommittee on the scientific soundness of USGS and MMS assessment methods last year.

RESERVES AND RESOURCES

For the record, I would like to define certain terminology and define the part of the resource spectrum that is addressed by Resource Assessments. Figure 1 was developed jointly in 2000 by AAPG, the Society of Petroleum Engineers (SPE), and the World Petroleum Congress (WPC), and has been published by the SPE.

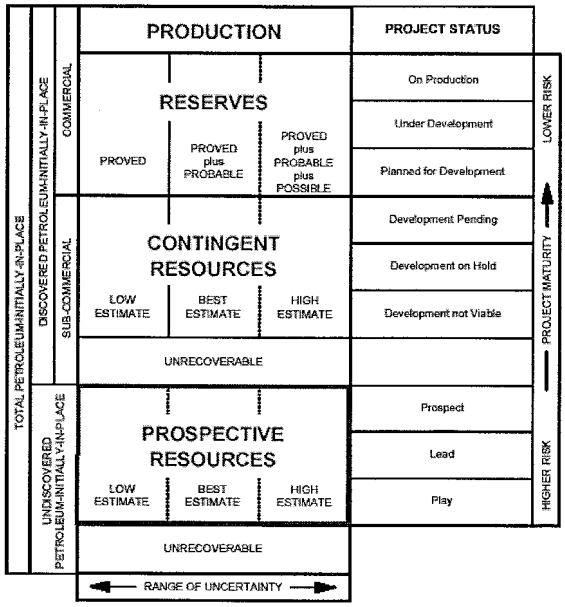
At the top of the figure, we define "reserves" as having been discovered and commercial in nature. We discuss them as being proved; proved plus probable; and proved plus probable plus possible; thus conveying a degree of certainty about the quantity.

Figure 1 shows the highlighted box that is the primary focus of today's testimony. Resources are potential, undiscovered, estimated volumes of hydrocarbons. The estimates are based on our current state of geological knowledge and existing technology. Whether resources are ever converted to reserves is dependent on economic conditions, policy decisions, and incentives for companies to perform exploration activities. As exploration proceeds and more geological data is collected, our ability to make better estimates of resources increases. Also, as resources are converted to reserves, supply increases and the ability to meet demand improves. We discuss resources in terms of low estimate, best estimate, and high estimate. These levels of estimation are driven by our geological knowledge, available data, and the technology available to assess them.

Let me restate: in order for resources to be converted to reserves and ultimately to supply, exploration and development has to take place. The exploration process

consists of leasing acreage, acquiring and interpreting seismic and subsurface data, and drilling.

FIGURE 1: RESOURCE CLASSIFICATION SYSTEM
(showing possible Project Status Categories)



Note: For illustrative purposes only. Not to scale.

U.S. ENERGY RESOURCES

AAPG believes the U.S. still has a large energy resource remaining to be tapped. We believe the techniques and scientific methods used by both the MMS and USGS are sound and provide a good basis for discussion of a national energy policy.

Studies by the USGS and NPC have concluded that the most prospective areas for major new discoveries, particularly natural gas, are on public lands in the Rocky Mountain sedimentary basins, offshore in the Gulf of Mexico, in the Eastern Gulf of Mexico, and on the Atlantic and Pacific Outer Continental Shelf. AAPG concurs with this assessment. Despite the huge potential of these areas, Federal law presently prohibits exploration on the Atlantic and Pacific OCS and in the Eastern Gulf of Mexico. Access to much of the remaining resource potential of the Rocky Mountain basins is restricted or closed. The total estimated gas resource of these areas is 213 TCF (per NPC 1999 study). For comparison, the US currently produces approximately 19 TCF per year and imports another 3+ TCF/year from Canada. It is likely that with further exploration, these resource figures would increase significantly. Unfortunately, a significant amount of that resource is subject to restrictions as tabulated in Table 1 and shown in Figure 2. In the case of the Rocky Mountain Region, the resource subject to some restriction amounts to two-thirds of the total estimated resource.

Table 1: Amount of U.S. Oil and Gas Resources Subject to Restrictions

Area	Oil (Billions of Barrels)*	Gas (Trillions of Cubic Feet)*
ANWR	7.6	2.7
Atlantic OCS	2.1	31
Eastern Gulf of Mexico	3.6	24
Pacific OCS	10.7	21
Rocky Mountain Region	2.7**	137 ***
Total	**26.7**	**215.7**

* Figures are estimated to be Mean technically recoverable resources
** 0.6 Billion Barrels are closed for development, 2.1 Billion have some restrictions
*** 29 TCF are closed to development, 108 TCF have some restrictions

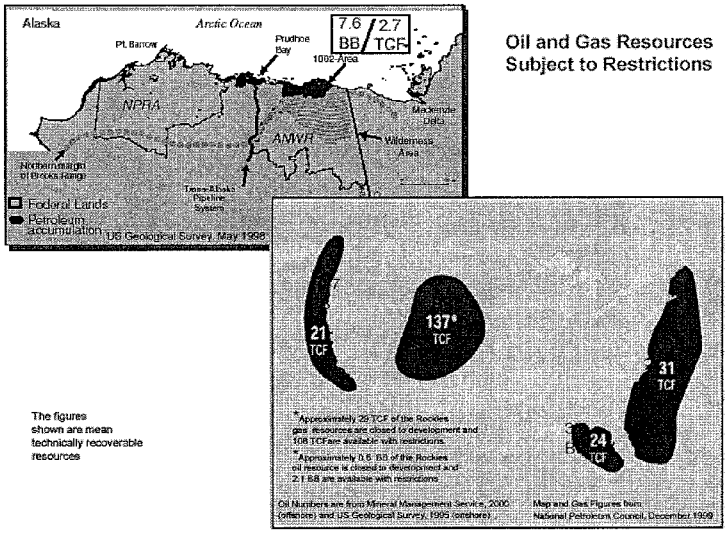


Figure 2

WHICH ESTIMATE TO USE FOR PUBLIC POLICY DECISIONS?

As this Subcommittee is well aware, under the reauthorization of the Energy Policy and Conservation Act in 2000, Congress asked the Department of the Interior to provide a scientific inventory of Federal Lands detailing the hydrocarbon resources estimated to be present on these lands and restrictions and impediments to development of these resources. This inventory would be used for management of land and energy resources and should form the basis for policy decisions required for balancing the nation's need for energy and the imperative for environmental conservation. As we understand it, these studies are still in progress.

Recently, questions have been raised criticizing the 1995 USGS National Oil and Gas Assessment, 1999 National Petroleum Council study and the 2001 Department of Energy's Greater Green River Federal Lands Analysis. The USGS, NPC, and DOE studies described the undiscovered oil and gas resources that may be present on the areas addressed by these reports. In addition to the "technically recoverable" resource, the USGS assessment and the NPC study did address the economically recoverable resource under various price and development scenarios.

The RAND Issue Paper proposes substituting viable resources for technically recoverable resources as the base that matters for policy decisions. The problem with this approach is that the viable resource is not a prerequisite for sound decisions, but is itself an outcome of many decisions, such as decisions on which technologies to develop and deploy, on what constitutes environmental "acceptability", and the like. The effect of land and access restrictions should be assessed in terms of both their short- and long-term effects on the entire nation's supply and security. The latter clearly requires technically recoverable resources.

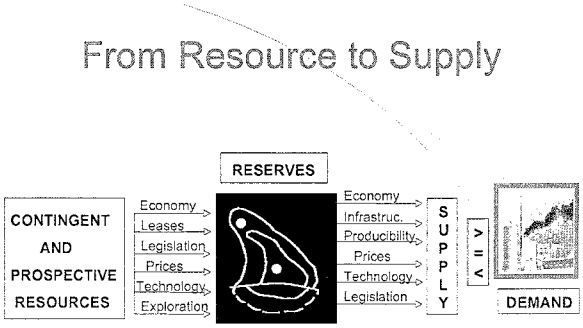
It is AAPG's firm belief that technically recoverable resource is the correct base to use when making policy decisions on competing use of Federal lands. Although, further analysis of this resource base is perfectly justified depending upon policy issues to be addressed, only the total resource base can be used to balance against other competing social and environmental uses or preservation of these lands.

Although the economic analysis carried out by the USGS and NPC studies is valid and adequate, oil and gas companies considering exploration in any area perform their own economic analysis for their decisions. Each company has its own economic criteria and risk profile to determine whether they wish to explore in a basin. They will start with the technically available resource and assign their own criteria to make a decision. As Figure 3 shows, there are many factors that affect the conversion of Resources to Reserves and then Reserves into Supply. Legislation in the form of access or non-access, "standard lease terms" or "restricted access" or permanent or temporary moratoria are part of the equation. However, if the hydrocarbon

resource base is to be weighed against all other competing interests in a given piece of land, the technically recoverable resource base is the logical starting point. That is also the only quantity that has the least chance of being manipulated for philosophical, political, and personal-interest reasons.

Assumptions of price, drilling costs, transportation costs, etc. are only good for the day they are made. As we have seen in the last ten years, a two- to three-fold change in oil and gas prices is not uncommon, nor is a similar change in the costs associated with exploration. In addition, a company that is already operating in a basin will have a different risk profile and economic criteria than a company that is new to that basin. The companies look at various plays on a long-term basis and understand there are economic risks and that a continuous reservoir or non-conventional play that may take hundreds of wells to develop is going to have a long lifespan and the project will see a lot of price fluctuations during its lifetime.

The whole objective of the studies being conducted under the EPCA reauthorization is to determine the balance between competing public interests. If the "cost" of environmental impact were used right in the beginning to diminish the volume of available resource in the Rockies, then according to some groups, no resources would exist.



We have a very recent example of the impact of this approach. The MMS conducted OCS Sale 181 in December of last year in the Eastern Gulf of Mexico. By all accounts, it was a successful sale with seventeen companies participating. A total of $459 million was bid at the sale, which offered 233 tracts. Successful bids on 95 blocks totaled $340 million. However, prior to the scheduled sale, 800 blocks covering 3.4 million acres were deleted from the sale for political concerns, even though the blocks were as much as 100 miles offshore. Initially, these 800 blocks had passed the same environmental filter that the other 233 blocks had. The Federal government lost valuable revenues and future royalty payments, and the nation lost potentially valuable additions to the resource base.

I would directly address the question of "viable resources". Viability speaks directly to changes in costs, prices, accessibility and technology. After all, at one time none of the modern inventions that we take for granted, such as the telephone, or the computer, or the airplane were "viable". More specifically to the oil and gas industry, drilling and producing in 10,000 feet of water or multilateral drilling to access resources from a central point, or commercial production of coal-bed methane were not considered "viable" at one time. Thus we believe that viability hinges on market need. And market need drives technological innovation.

ISSUES SPECIFIC TO ROCKY MOUNTAIN BASINS

Although the purpose of our testimony is not to specifically counter the points raised in the RAND report, we would like to address some of the issues mentioned.

It has been suggested that any study of the basins should consider the restricted portion of only the economically viable resource. The NPC study did evaluate both technically recoverable and economic resources. In various scenarios evaluated in the study, NPC found that a high percentage of the assessed undiscovered resource base in the Rockies is either economic now or will become economic through the year 2015. This conclusion has been verified by the level of industry interest in the

region and the region's growing gas production. The NPC study used economic viability of new prospects as the primary determinant of future industry activity, reserve additions and production. The study showed that most of the assessed Rocky Mountain volumes are economic to develop, either now or in the future, and that a large volume of these resources is likely to be in areas where industry access is restricted. Gas production in the Rockies would be 800 BCF/year greater in 2015 with less access restrictions. This incremental Rockies production would satisfy approximately one-quarter of California gas demand in 2015.

The RAND report also questions various aspects of "access restrictions" that were tallied and considered in the NPC study. Through a detailed analysis of six calibration areas in the Rockies, the NPC Study arrived at three lease classifications and their percentages:

Lease Types	Percentages
Off Limits	9%
Higher Costs Due to Access Issues	32%
Standard Lease Terms	59%

It should be pointed out that before any Federal Lands are available for leasing, they undergo Environmental Impact studies. The "Standard Lease Terms", although "unrestrictive", incorporate environmental objectives. Any economic study based on these terms already incorporates "environmental acceptability". Thus, to reduce the resource base on the basis of "environmental acceptability" would amount to a double jeopardy against that resource base.

Those areas with higher costs were subject to increased drilling costs and drilling delays. The cost penalty was computed as a weighted average of the types of restrictions and mitigation measures that were expected to be encountered in the high cost areas. Some access restrictions are sometimes waived, but they almost always accompany costly mitigation measures. New access restrictions are placed on "standard lease terms" as new areas for drilling are reviewed. The net effect could well be a greater cost penalty than the values used in the NPC study. Additionally, restrictions on public lands many times impact access and costs of operation on non–Federal lands as well.

One of the important conclusions of the NPC study was that the Rocky Mountain region could supply a growing amount of the country's natural gas needs. Therefore, policy makers should weigh the economic and environmental benefits of this potential gas supply against policies that might restrict access to the region's natural gas resources.

AAPG has always stated that oil and gas exploration, development and production can and does co-exist with environmental preservation in every producing region of the country. Various state and Federal regulations and lease stipulations and monitoring ensure that. However, each time the Congress reviews the nation's need for growing oil and gas demand and attempts to find ways to secure additional domestic supplies, we hear calls for permanent closure of highly prospective areas.

ACCESS TO GAS RESOURCES ON FEDERAL LANDS

Even the environmental groups cite natural gas as a cleaner, environmentally more benign energy resource to fuel our economy. However, access to the huge gas potential of undeveloped public lands is limited, in the Western states and on the OCS. Additionally, the Federal regulatory maze hinders domestic petroleum exploration operations and investment.

The U.S. cannot depend on gas imports from OPEC to meet rising demand. Natural gas is a North American commodity that is locked into a pipeline delivery system. Imports from Mexico will be minimal. The 1999 NPC study projected LNG imports of less than 1% of supply through 2015. That same study projected U.S. gas demand in 2010 to be 29 TCFG on an annual basis and projected U.S. production to be 25 TCFG/yr. The shortfall, according to the NPC, will be made up by 4 TCFG of imports from Canada. What happens if the Canadian imports do not materialize? The United States must develop its own gas resources to meet future demand. This requires access to the public lands that are deemed most prospective for natural gas.

Conservation and renewable energy resources often are cited as the solution to our energy requirements. This is not a realistic expectation if one appreciates the actual tiny magnitude of current alternative energy, and that fossil fuels supply 88% of our primary energy. Energy conservation has been effective in certain areas, particularly in regard to increased miles per gallon for automotive engines. Those efforts obviously, must continue. But they will not be sufficient. For the mainte-

nance of a growing economy additional hydrocarbon resources must be identified and brought into production for the foreseeable future.

Despite DOE expenditures of over $9 billion since fiscal year 1980 on solar and other renewable energy research, alternative energy resources provided only 0.3% of primary energy supply in 1999, exclusive of traditional hydroelectric power (3.8%). Obviously time and effort for research must continue on alternate energy resources, but we cannot count on these sources to meet our nation's needs in the short term.

AAPG does not advocate any reduction in alternative energy research. However, the fact is, that our economy will continue to depend on fossil fuels for the majority of the nation's primary energy requirements for at least another generation. On April 18, 2000 at the AAPG Annual Meeting in New Orleans, Jay E. Hakes, Energy Information Administrator, presented a paper entitled "Long Term World Oil Supply". One of the conclusions in that paper was that with an estimated mean ultimate recovery of 3.0 trillion barrels worldwide, and production growth rates of 0–3%, the estimated peak year of world oil production would range from 2030–2075. That is at least another one-half century of hydrocarbons being a significant part of our energy mix.

RESOURCE ASSESSMENTS

I would like to return to the issue of which assessment numbers should be used for public policy decisions. Organizations such as the USGS, MMS or the NPC have carried out assessment based on geological data, scientific knowledge, and proven tools available to them. At times the agencies have been "behind" industry's thinking, especially in the area of new or evolving exploration plays because they do not have access to all the data. For example, the latest information on economic production of natural gas from coal seams in the Powder River Basin of Wyoming is probably only known to the companies currently operating in that area. As a result, the assessments have sometimes been too conservative and have required subsequent revisions. Until emerging plays are proven and at least some of the data becomes public, the agencies assign limited resources to them, and rightly so. Once these kinds of "frontier" plays have been discovered and proven by the risk takers of industry, the total resource impact can be assessed.

One of the characteristics of assessments we have discovered is their tendency to grow in size over time. This is due to increased exploration and gathering of subsurface data, improvements in geological knowledge, and acquisition of additional seismic data. As our knowledge of a basin increases, so does our ability to estimate its resources; which generally results in an increase in the size of the resource. That also is why exploration is so competitive. Different interpreters can look at the same data set, and draw dramatically different conclusions about exploration prospects. For example, in the late 1960's M. King Hubbert estimated the ultimate gas resource for the United States (excluding Alaska) to be about 1,044 TCFG. In 2000, the estimate is almost twice that amount at 2,000 TCFG.

Tight sandstone reservoirs are very prominent in many basins of the Western U.S. In its 1995 study, the USGS assigned 200 TCFG of recoverable resource to this type of reservoir in the Rocky Mountain Basins. The USGS is currently embarking on a reassessment of resources in this type of reservoir, because recent exploration has established new geological concepts and USGS has revised its own assessment methods for unconventional reservoirs. Given the nation's desire to switch to natural gas wherever economically feasible, this could be one of the most important assessments the USGS will perform. AAPG has evaluated the revised USGS methodology to assess such reservoirs and has endorsed this methodology.

SUMMARY

RAND corporation's own statement of research principles describes that any research should be well designed for the problem, that it should be based on sound information, that it should be balanced and independent and should be relevant to client's interest and needs. It also states that it should take into account the relevance of previous work. We believe that the clients, the citizens of the United States, deserve a sound energy policy that maximizes domestic production with utmost care for the environment. However, the clients' needs are ill served by insisting that we have ample sources of energy while putting restrictions on its supply, that we use more natural gas while shutting areas from where the gas might come, by insisting that we use alternative energy sources while having no viable alternative source in the near future, and by insisting that oil and gas development by definition spoils the environment while the facts are otherwise. The RAND Issue Paper essentially argues for "proving" that a given area contains technically recoverable, economically profitable, and environmentally suitable resource before access

issues can be decided. However, without access to the area in the first place, its potential cannot be tested or realized.

AAPG firmly believes that the nation has a right to decide which type of lifestyle we should have. In order to evaluate competing interests in the use and nonuse of possible resources, the decision makers should know the total extent of possible resources just like they have the right to know the total extent of all other social, economic, and environmental concerns. Technically recoverable resource is the only number that addresses the full base of possible energy resource. All other concerns should be weighed against that number.

AAPG ENERGY POLICY RECOMMENDATIONS

The United States has abundant energy resources. However we are now faced with a real energy crisis, because the nation has not developed and implemented a comprehensive energy policy. In order to assure that our way of life is not dramatically impacted because of energy shortages, the AAPG recommends the following:

- The U.S. must develop a national energy policy that provides dependable, affordable, and uninterruptible energy for the public and commerce, and is based on a sound scientific assessment of the nation's resources and reserves.
- Energy policy must address the needs of all stakeholders, especially the consumers, and not over react to the demands of the shrillest interests with the most money for publicizing a particular position.
- Energy policy must be strategic and long-term, not "quick fixes" to short-term "crises".
- Energy policy must include a role for all energy sources, including coal and nuclear energy.
- Resource assessments are a vital planning tool for policymakers and industry. The agencies that perform these assessments and track oil and gas resources and reserves need continued support. They have done a good job to date.
- A major long-term and capital-intensive industry effort is required to explore for, develop, produce, and build the infrastructure necessary to deliver the energy supplies required to meet projected demand. Energy policy must facilitate processes that attract capital investment in energy development without creating costly and time-consuming regulatory roadblocks.
- Industry access to public lands, which might contain hydrocarbon resources, should be a priority to encourage domestic energy sources. We cannot become further and more dangerously dependent on unreliable foreign energy imports.
- The public must be assured that energy resource development can be accomplished in an environmentally sensitive manner. The technology is available to do this and the petroleum industry already practices such environmental responsibility.
- The impact of the Kyoto Protocol on the ability of the nation to supply the energy needed to fuel our economy without major disruptions must be carefully evaluated.

On behalf of AAPG, I thank the Subcommittee for giving us this opportunity to testify.

[Responses to questions submitted for the record by Mr. Mankin follow:]

OVERSIGHT HEARING ON "OIL AND GAS RESOURCES ASSESSMENT METHODOLOGY"

APRIL 18, 2002

Questions from the Majority

1. What is the oil and gas potential of the Rocky Mountains and why is the EPCA inventory important?

As the energy needs of the Nation continue to grow, the geologic basins in the Rocky Mountains have been identified as a significant future source of energy to help meet these needs. At the same time, this region is one where environmental concerns are paramount. This situation has borne the recognition that it would serve the Nation's interests to quantitatively assess and identify broader issues regarding the potential for oil and gas development based upon environmental considerations. Such study will help to clarify the debate and assist energy policymakers and Federal land managers to make constructive, rational decisions concerning oil and gas resource development in the region.

According to the NPC (1999) study, the Rocky Mountain region has 213 trillion cubic feet of mean technically recoverable resource. The comparable oil figure is 4.0 billion barrels (USGS, 1995 National Assessment).

The EPCA inventory represents a systematic, multi-basin analysis quantifying the Nation's oil and gas resources based upon environmental considerations. We believe these studies will prove useful for highlighting those critical areas that have high oil or gas resource potential for supplying the Nation's energy needs, while at the same time quantifying the nature of environmental stewardship currently in place. We believe that these studies will provide a foundation for addressing energy and environmental concerns and should streamline efforts to alleviate the conflicts between them.

2. Has there been a problem with regional oil and gas assessments being unduly optimistic? Can you cite any examples where regional assessments were too pessimistic?

We believe that the assessments carried out by professional organizations such as the United States Geological Survey or the Minerals Management Survey are done based on the data, assumptions, and geological concepts prevailing at the time the assessment is conducted. However, the history shows that the figures tend to increase through time. This happens because existing fields have a history of "growing" in size through time and new geological concepts and new technology make previously inaccessible resources accessible and tested as shown in the graph below.

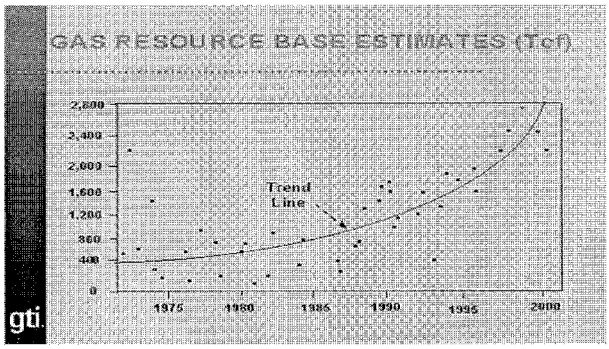


Figure 1 (Gas Technology Institute, 2001)

3. Can we determine the ultimate amount of the oil and gas in place from a regional assessment?

As explained in answer to the previous question, the concepts, assumptions and geological information continue to expand and evolve. Hence, the ultimate amount of oil and gas in place from a regional assessment always will remain the most educated estimate at a given time.

4. Which is more sensitive to long-term change and short-term periodic fluctuations, a regional assessment of oil and gas resources or the economic evaluation of the resource predicted from a regional assessment?

Fluctuations in oil and gas prices obviously impact economically recoverable resources in the short term. However, as shown in the graphic above, the total resource estimates tend to grow through time. The same factors (geologic concepts, technology, and field growth) also tend to impact the economically recoverable resource in an upward trend as well in the long term.

Questions from the Minority

1. Dr. Mankin, you cite results from the 1999 National Petroleum Council report on gas supply and demand. In modeling future demand for gas, what simplifying assumptions did the NPC report use?

Would you agree that these assumptions ignore the market incentives for these non-gas energy industries to invest in new generation capacity in response to market prices?

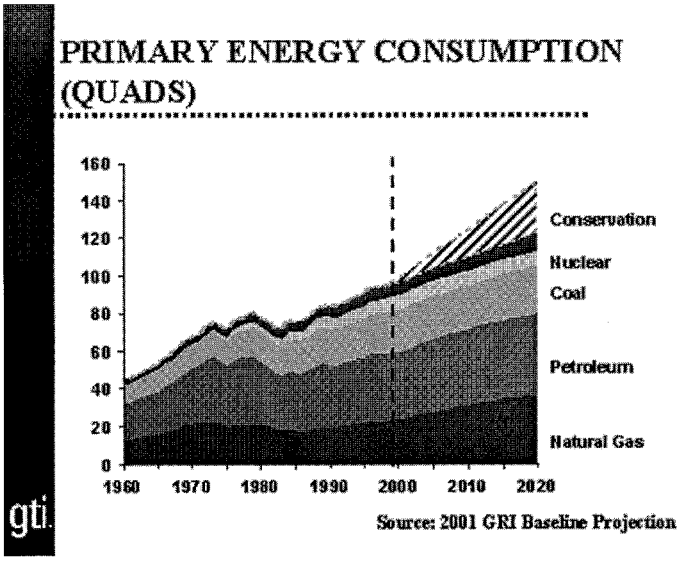


Figure 2 (Gas Technology Institute, 2001)

Major Demand Assumptions:
1. GDP will grow at 2.5% per Year
2. 140 GW of New Power will come on Line by 2015
3. 70% of New Gas-fueled Power Projects could Switch Fuels
4. No New Nuclear Facilities will be Built
   a. 30 GW of Nuclear Capacity up for Relicensing by 2015
   b. Of this, 15 GW of Nuclear Generation will Retire
5. Another 15 GW of Nuclear Power will get License Extensions
6. Coal Capacity Utilization will increase from 64% to 75%

As shown in the graph above, natural gas, petroleum, and coal account for almost 90% of the primary energy consumption. In the year 2020, even with a significant component being derived from conservation, this figure would drop at best to 70%. With concern for the environmental effects of burning coal and large coal-bearing areas in the United States being off-limits to exploration and development, the Nation's continuing decline in oil production, and demand for "clean burning" fuels, we believe that NPC estimates are fair and realistic. We believe that the nation would be well served to prepare to meet that demand.

2. Assuming that additional investment is forthcoming in liquid gas, hydroelectric or renewable energy facilities, wouldn't you agree that the gas demand estimates in the 1999 NPC report are overestimated?

Hydroelectric supplies only 3.8% of the nation's primary energy supply. We do not see any additional hydroelectric facilities on the horizon. This is because there would be many objections due to land condemnation resulting from reservoir flooding. Actually, hydroelectric generation is lower than what the NPC projected due to drought conditions.

By liquid gas, we assume that you mean Liquidified Natural Gas (LNG). The NPC study projects that gas from LNG projects will increase from 100 BCF/yr, as of 1999, to about 800 BCF by 2015. This is a very small part of the total demand.

Despite a Federal expense of $9 billion in research funds for alternative energy sources since 1980, only 0.3% of the Nation's primary energy comes from alternative sources. The Nation wants clean, reliable and affordable source of primary energy. Against such a background, it can hardly be said that NPC report overestimated the gas demand.

3. Why wouldn't future investment in conservation and energy efficiency also reduce the demand for gas estimated in the NPC study?

The NPC Study did assume improving energy efficiency. It projected that 50% of increased gas demand by 2010 would be from increased electricity demand. The

long-run income elasticity for electricity grid sales assumed by the NPC averaged 0.80 across all regions of the U.S. That is, if the economy grew 2.5 percent per year, then electricity sales would grow 2.0 percent. Regarding Residential and Commercial uses of gas, the NPC Study also factored in:

- Housing stock increasing with population
- Housing size increasing with income
- Gas market share grows for appliances
- Energy efficiency improving per household

However, as shown in Figure 2, even with conservation and energy efficiency accounting for 15% of primary energy consumption by the year 2020, more than 70% of primary energy needs have to be met by coal, oil or natural gas. This scenario still implies a 25% growth in the energy derived from coal, oil and natural gas. Thus, the NPC estimate of demand for gas is quite realistic.

4. The NPC report discusses the ability of industry to access oil and gas with directional drilling from 5–6 miles away. In fact the report states (page 14) that the industry could set up "drilling operations on the White House lawn and extract hydrocarbons from beneath most of Washington, DC and into its suburbs."

In your testimony you cite the NPC estimate of 137 TCF (trillion cubic feet) of gas being off-limits in Rocky Mountains due to access restrictions.

In generating this estimate the ability of industry to use directional drilling was not considered.

However, the NPC also report promotes directional drilling technology but than assuming it doesn't exist when examining access. Why the inconsistency?

Actually, there is no inconsistency, but differences between exploration and development drilling explains this apparent "inconsistency." While it is true that in a development setting (that is, once the oil or gas has been discovered and determined to be economic), long-offset drilling can occur and is often an economically advantageous way to develop a field. However, the discovery of the field must come first, and this is done with vertical (or high angle wells). Without land access (including access to seismically defined exploration targets), exploration wells cannot be drilled.

By statute, directional drilling cannot be used to drill under unleasable lands from leasable areas. While the NPC study did not explicitly address the use of directional drilling, a follow-up study of the Greater Green River Basin did (Department of Energy, 2001). Federal officials and industry operators were canvassed to determine an appropriate distance into so-called "no surface occupancy" areas (where a drilling rig cannot be sited). The directional drilling capability is partially a function of the depth to drilling objectives—generally the deeper the objective, the farther the kick-out of a well can be. In practice, for exploration settings in western basins of the U.S., the typical kick-out distance is estimated to be about one-fourth of a mile.

5. The NPC report included sensitivity analysis to see how the "access" results changed if key parameters were altered. The NPC report also examined the potential impacts of reduced access to gas resources in the Rocky Mountain Region-analogous to implementing the roadless area conservation rule or enforcing gas lease stipulations.

In this scenario, reduced access in the Rocky Mountain region had very little impact on gas prices.

The NPC report also included sensitivity analysis on access. They re-ran the model assuming less access in the Rocky MountainsCwhich can be considered a proxy for the lease stipulations.

The NPC results found that, "The changes that occurred in the reduced access sensitivity case were not pronounced" (page 43)

As such, it seems to me that the impacts of leasing stipulations will have very little impact on gas prices. Is this conclusion consistent with the findings in the 1999 NPC report?

Based on detailed analysis of six calibration areas in the Rockies, the NPC Study arrived at three lease classifications and its respective percentage of the resource base (see table below).

Lease Type	Reference	Increase	Reduced
Off Limits	9%	9%	14%
Higher Costs Due to Access Issues	32%	32%	64%
Standard Lease Terms	59%	59%	22%
High Cost Penalty Per Well (% of Well Costs) (*)	6%	0	6%
High Cost Delay Period (Yrs)	2	none	2

(*) Approximately $25,000 per well

The reason why the reduced access case was less pronounced was because the NPC Reference Case already had substantial restrictions built into it. Additionally, the "Off Limits" percentages did not increase all that significantly. It would have been a more interesting scenario if the "Off Limits" percentage had increased to about 25% of the resource base. In retrospect, the NPC did not make the Reduced Access Case "bad enough".

6. How was the amount of economically recoverable gas estimated in the NPC report?

The GRI Hydrocarbon Supply Model (HSM) was used in both the 1992 and 1999 NPC Studies. The HSM was developed by Energy and Environmental Analysis, Inc. (EEA) for the Gas Research Institute (GRI) in the early 1980's and has been continually updated since that time. The HSM is a PC-based analytical framework designed for simulation, forecasting and analysis of natural gas, crude oil, natural gas liquids and for cost trends in the US and Canada. The HSM is a process-engineering model with a very detailed representation of potential gas resources and the technologies with which those resources can be proved and produced. The degree and timing by which resources are proved and produced are determined in the model through discounted cash flow analysis of alternative investment options and behavioral assumptions in the form of inertial and cash flow constraints and the logic for setting producers market expectations (e.g., gas prices).

7. Why is the amount of gas economically recoverable so much greater than the amount estimated by USGS scientists?

It is always difficult to compare one study versus another without comparing the coverage, resource category definitions, methodology, statistical analysis and legitimate difference in data interpretation. The USGS study was conducted in 1995 whereas the NPC study was carried out in 1999. During the intervening years, the Gulf Coast offshore, especially the deepwater, produced significant discoveries. This fact might have induced the NPC study to produce a larger number. In fact, recent studies have pointed out that deepwater Gulf may be more oil prone than gas prone. Thus, gas contribution from deepwater Gulf may not be as much as might have been originally supposed.

At the same time, USGS is currently reviewing its resource estimates for unconventional gas resources. A significant amount of new data have been generated in many gas-prone western US basins. USGS also has revised its assessment methodology for such resources. Thus, some of the unconventional gas resources may be revised upwards significantly.

Similarly, economically recoverable estimates are highly dependent on the economic model applied, especially the gas-price assumptions. In addition, assumptions

for exploration and development costs, lease development costs, discount factors etc., may also vary from study to study.

We believe that both the NPC and the USGS studies are valid and utilize appropriate scientific methodology. Both studies point out that the Nation does not lack in gas resources. What is needed is a coherent national energy policy that ensures that the Nation will have ample gas supplies to meet the growing demand.

Ms. CUBIN. Thank you, Dr. Mankin.

And I now would like to introduce Peter Morton, Ph.D., resource economist with The Wilderness Society. Mr. Morton.

STATEMENT OF PETER A. MORTON, PH.D., RESOURCE ECONOMIST, THE WILDERNESS SOCIETY

Mr. MORTON. Thank you, Madam Chairman. I appreciate the opportunity today to testify. I am Dr. Pete Morton. I am a resource economist in the research department of The Wilderness Society, a 175,000-member national conservation group that focuses on public land issues.

I would like to begin today by endorsing the methods recommended in the RAND report. I think the authors have done an excellent job evaluating the strengths and shortcomings of past reports in order to provide the basis for developing improved methods for assessing oil and gas resources.

It is important to note that the RAND report is not a condemnation of past assessments, or of the utility of quantitative modeling for policy development. Rather, reviewing methods, identifying shortcomings, and making recommendations are a healthy part of the scientific process.

As the RAND report correctly points out, oil and gas leasing stipulations that dictate where, how, and when drilling may occur are not in many cases binding constraints on energy production. Economics and the rugged and remote terrain play more important roles in determining the economically viable resource.

I would like to focus the rest of my testimony on key variables that I believe should be included in assessments.

One, resource assessment should include the private and public land: i.e., the entire resource base, including private land, is needed to address the split estate issue, private land with Federally owned resources located underneath. Industry has ready access to these resources, despite the objections of many private land owners. In the Rocky Mountains, for example, approximately 35 percent of the gas lies under non-Federal land.

Two, resource assessment should include oil and gas reserves. Quite simply, most of our oil is located where we have already found it; in or near existing reserves. Since 1990, 89 percent of oil and 92 percent of gas reserve additions have come from existing fields, and the USGS predicts this trend will continue.

Three, resource assessments should rely on USGS data. We believe that USGS mean estimates provide the best unbiased point estimates of the expected value of undiscovered oil and gas resources.

Four, resource assessments should be based on the amount of oil and gas that is economically recoverable; not the amount that is technically recoverable. The opportunity cost of a policy or action equals the net benefits foregone as a consequence of that policy or

action. One of the common mistakes made when evaluating regulations or decisions to limit access is the use of gross revenues when estimating opportunity cost, rather than net revenues. The opportunity costs of leasing stipulations should equal the net economic benefits of oil and gas foregone. This is consistent with economic theory.

The use of technically recoverable oil and gas, rather than economically recoverable, is similar to the incorrect use of gross revenues rather than net revenues when evaluating policies. The Congressional Research Service has recommended that economically recoverable resources be the basis of policy analysis. If economic constraints on production are ignored, the assessments will over estimate the quantity of oil and gas potentially off limits.

To reiterate, if the oil and gas is not economically feasible to extract, there are no adverse impacts on supply or price from lease stipulations designed to protect wildlife, archeological sites, recreationsites, or other public resources. Since policymakers should be concerned about the actual impacts, not hypothetical impacts, the economically recoverable resource is the policy relevant measure.

And when economic criteria are considered, the amount of oil and gas recoverable drops significantly. In the Green River area of Wyoming and Colorado, for example, 90 percent of the gas is tight gas, located in low-permeability geologic strata. According to the USGS, only 7 to 15 percent of the tight gas is economic to recover. Similar financial constraints apply to coal bed methane located more than 5,000 feet under ground. So coal bed methane located 10,000 feet underneath a roadless area, for example, would have an opportunity cost of zero, regardless of whether that area remains roadless.

Resource assessments should include access available with directional drilling. According to the National Petroleum Council, directional drilling allows access to resources 5 to 6 miles from the drill site. We therefore recommend that assessment utilize a conservative 3-to-4-mile directional drilling distance.

Resource assessment should also consider the positive impact of technology on access. Technological improvements will, over time, reduce the amount of gas that is inaccessible, either through drillbit technology or making directional drilling feasible from a farther distance.

Finally, it is important to recognize that while leasing stipulations might reduce access to oil and gas, they help conserve the other multiple uses enjoyed by the public on their land. Seasonal closures necessary to protect raptor nest sites and critical elk habitat, for example, conserve the wildlife and other multiple uses under which public land is managed. Legislative intent and public sentiment indicate that public land should not be for the exclusive use of the oil and gas industry.

Conclusions: Based on the analysis of USGS data, it is clear that drilling public lands will do little to affect our energy future. We should therefore not assume that extracting energy resources is the highest and best use of our public lands, because in many cases it is not.

The marginal benefits from wildland conservation, leaving public land wild and roadless, are in most cases much greater than the marginal opportunity cost, in terms of the energy resources foregone.

Once again, thank you for the time to testify.

[The prepared statement of Mr. Morton follows:]

Statement of Peter A. Morton, Ph.D., Resource Economist, Ecology and Economics Research Department, The Wilderness Society

I am Dr. Peter Morton, Resource Economist in the Ecology and Economics Research Department for The Wilderness Society, a 175,000-member national conservation group that focuses on public land issues. I appreciate the opportunity to testify today regarding methods for assessing oil and gas resource and the potential access restrictions on extracting those resources.

I will begin by endorsing the methods recommended in the recent RAND report "Assessing Gas and Oil Resources in the Intermountain West: Review of Methods and Framework for a New Approach." I think the authors have done an excellent job evaluating the strengths and shortcomings of past assessments of oil and gas (e.g. Department of Energy 2001, National Petroleum Council 1999), in order to provide the basis for developing an improved methodology for assessing the "economically viable resource". It is important to note that the RAND report is not a condemnation of past assessments or of the utility of quantitative modeling for policy development. Rather, reviewing methods, identifying shortcomings, and making recommendations are a healthy part of the scientific process.

As the RAND report correctly points out, much of the potentially restricted oil and gas resources would never be developed because they are inaccessible for other reasons. The oil and gas leasing stipulations that dictate where, how, and when exploratory drilling may be conducted in order to protect wildlife and the environment are not, in many cases, binding constraints on energy production. Economics, terrain and technology may in fact play more important roles in determining the "economically viable resource". I strongly agree with RAND's recommended improvements to base assessment on the oil and gas that is economically recoverable, include reserves, include private land, account for stipulations waived, include directional drilling, consider pipeline access and multi-season drilling. These recommendation are consistent the ones I made with respect to improving the Department of Energy's Green River report released last year (Morton 2001). As the RAND report noted, including wellhead cost, infrastructure costs, and environmental costs in the assessment of viable resource will likely have the greatest impact on the amount of oil and gas estimated to be economically viable. Accurately assessing these costs is the key, and these proposed methods will make an important contribution to the debate.

In the rest of my testimony I will expand on the above points, focusing on what I see as the key variables or parameters in the debate over oil and gas assessment methodologies. These include:

- the land and resource base assessed should include private and public land, as well as discovered reserves;
- the assessment should utilize USGS mean estimates for economically recoverable oil and gas (rather than technically recoverable), estimated using a range of prices;
- the assessment methods should use a directional drilling distance of 3–4 miles, consider multi-season drilling opportunities and consider the increased access that will be available with future technology; and
- account for the market and non-market economic costs including those associated with increasing the scale of production beyond the assimilative capacity of communities and ecosystems.

Resource Assessments Should Include Private and Public Land.

When accessing oil and gas resources it important to account for the entire resource base, including private and public lands. In the Rocky Mountains, for example, approximately 35 percent of the gas lies under non-federal land (RAND 2002). A narrow focus on public lands will overestimate the oil and gas resources subject to access restrictions. Because non-federal lands are not subject to Federal lease stipulations, oil and gas resources underlying them are subject to standard lease terms that are not necessarily restrictive. Using the total land as a basis would therefore reduce the fractions of resources subject to potential access restrictions. For example, based on an analysis of data in the National Petroleum Council

report on natural gas (1999), when non-federal lands are included in the analysis, the percent of gas in the Rocky Mountain Region subject to potential access restriction drops from 56 percent to 35 percent. While we are critical of the recent Green River study by the Department of Energy, similar results can be derived. When non-federal lands were included, the percentage of access-restricted gas drops from 68 percent to 38 percent (RAND 2002).

Including private land in the assessment is needed to address the ability of industry to access Federal resources located underneath private lands (i.e. split estates). Split estates are lands where the surface rights are privately owned and subsurface rights are Federally owned and can be leased to private companies. An assessment of Federal resources should certainly include these private lands with Federal subsurface resources. Split estates are a huge challenge in the west, and the relatively open access to these resources—despite the objections from private landowners—should be included in the resource assessment. [1]

Figure 1 – Undiscovered Economically Recoverable Natural Gas at $3.90 per Mcf (onshore) and $2.11 per Mcf (offshore), (Tcf)

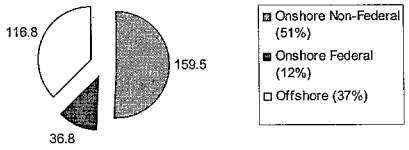


Figure 1 shows the relative contributions of undiscovered economically recoverable natural gas reserves from onshore federal and non-federal lands, and from offshore federal lands. Economically recoverable natural gas from onshore federal lands is about 12 percent of the estimated total undiscovered gas resource of 313 Tcf. Non-federal onshore lands likely hold, at most, 51 percent, and offshore lands hold at least 37 percent of total undiscovered economically recoverable natural gas (Source: Goerold 2001).

Resource Assessments Should Include Oil and Gas Reserves.

Oil and gas reserves are important to include in the assessment as they play significant roles in both long-term and short-term supply. Quite simply, most of our oil is located where we have already found it—in or near existing reserves. Oil and gas reserves are by definition economically feasible to bring to market. [2] "Reserve growth" refers to the increase in economically recoverable oil or gas as fields are developed. Reserve growth is perhaps THE major component of remaining U.S. gas resources (USGS 1996). Since 1977, 79 percent of the oil added to America's reserves came from development drilling in mature oil fields, while only 21 percent came from exploratory drilling in new areas (DOE 2002). Since 1990, the vast majority of reserve additions in the U.S.—89 percent of oil reserves additions and 92 percent of gas reserve additions—have come from finding new reserves in old fields (DOE 1999). These trends will continue as USGS estimates that the majority of economically recoverable oil and gas in America will come from already discovered reserves and growth of those reserves—in other words, oil and gas fields already developed and near existing infrastructure.

The dominant role played by our oil and gas reserves is clearly illustrated in Table 1. Assuming America were completely dependent on domestic production (we currently import 56 percent of our oil), we currently have about 15 years of oil and 21 years of gas in reserves and growth of those reserves. If, through investment in conservation and efficiency, we reduce our dependency on imported oil to 50 percent for example, our oil reserves will last twice as long as indicated in Table 1. Existing reserves and growth of those reserves, when combined with public and private investments in conservation and efficiency, provide us with 20–40 years to make a transition to a more efficient economy based on alternative energy sources such as hydrogen fuel cells, wind, and solar.

[1] Much of the land in the Powder River Basin of Wyoming is split estate land. An assessment of resource that focuses only on public land, ignoring split estate land, would mischaracterize the current situation by dramatically underestimating the access industry has to oil and gas in the Powder River. This underscores the need to include private land in resource assessments.

[2] The USGS (1998) defines reserves as "estimated quantities of crude oil, natural gas, or natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions."

Table 1. Economically Recoverable Oil and Gas in the United States

	Economically Recoverable as a Portion of Total U.S. Consumption	
	Oil	Gas
Reserve and Reserve Growth (existing wells and fields)	14.6 years	21.4 years
Drill All Onshore Federal Lands (undiscovered resources)*	222 days	1.7 years
Drill Arctic Refuge (undiscovered resources)	162 days	None
Drill private and state lands (undiscovered resources)	2.6 years	12.9 years

Source: USGS 1998, Mineral Management Services 2000. *Totals do not include Arctic Refuge

In contrast to reserves, the USGS estimates that only a small portion of undiscovered oil and gas resources can be recovered with a profit. As shown in Table 1, drilling the Arctic Refuge and other public wildlands will not significantly increase our energy supply or transition time. Drilling for undiscovered resources on Federal land, including national parks, national forests, lands managed by the Bureau of Land Management, and national wildlife refuges, would only meet U.S. demand for oil and gas for 222 days and 1.7 years respectively (USGS 1998)—with the Arctic Refuge adding an additional 0–6 months of oil. While the flow of oil and gas would obviously take place over longer periods of time, the results clearly show why we cannot drill our way to energy independence. Our demand is simply too high while our remaining undiscovered resources are too small.

Table 2 shows the location of our reserves and indicates that approximately 24 percent of our oil and gas reserves are located in Texas, with significant quantities in Alaska and offshore in the Gulf of Mexico. Somewhat surprising is that nearly 4 billion barrels of oil (about 20 percent of our reserves) are in reserves currently not in production (EIA 2001). Texas and Alaska together have around 1.3 billion barrels of oil in non-producing reserves. Significantly, non-producing reserves in the US have more oil than USGS estimates will be economically recoverable from the Arctic National Wildlife Refuge.

In addition to the significant contribution reserves make to long-term supply, reserves play an important role with respect to short-term supply, because reserves are most immediately available for injection into underground storage. And, the amount of gas in underground storage is a major supply factor influencing short-term market price and market instability (DOE 2001). With relatively inelastic demand for energy in the short-term, lower levels of working gas in storage (short-term supply) will, in general, lead to higher energy prices. Figures 2 and 3 clearly illustrate the recent inverse relationship between gas in storage and gas prices—the lower the storage levels the higher the price. From January 2000 through September 2001, working gas in storage was significantly below the 5-year average, resulting in the increased price volatility, which is reflected in the spike in natural gas wellhead price. Gas inventories were not the only inventories that were low; similar inventory shortages occurred in all the major energy markets. [3]

[3] In late 2000 and early 2001, the short-term inventories of major fuels were significantly below normal ranges, contributing to higher prices and hence the perception of an energy "crisis." An energy plan focused on drilling wildlands does nothing to remedy the causes of the recent energy crisis. A question for further investigation: What were the circumstances that allowed inventories—short-term storage levels—of all major energy markets, to be at such low levels during late 2000 and early 2001?

Table 2. Location and Totals for U.S Oil and Gas Reserves as of December 1999.

	Oil in Reserve	Gas in Reserve
	Millions of Barrels --	Billion Cubic Feet-
Texas	5339	40157
Alaska	4900	9734
California	3934	2387
Federal offshore	3297	25987
New Mexico	718	15449
Oklahoma	621	12543
Louisiana	600	9242
Wyoming	590	14226
Utah	268	3213
North Dakota	262	416
Montana	207	841
Colorado	203	8987
Kansas	175	5753
Alabama	49	4287
Other states	602	14184
Totals	21,765	167,406

Source: Energy Information Administration 2001.

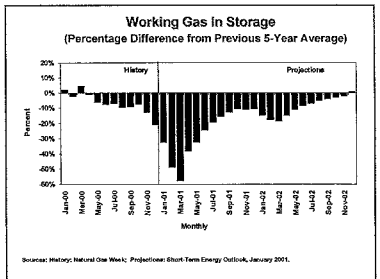


Figure 2. During the last half of 2000 and the first half of 2001, gas inventories were at historic lows.

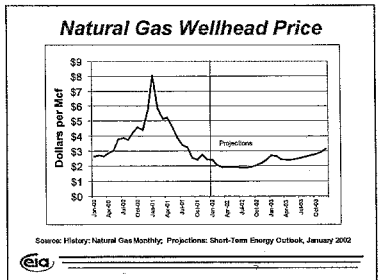


Figure 3. Very low levels of working gas in storage contributed to the price spike.

The following text from monthly reports from the Department of Energy underscore the important role that underground storage has on gas prices.

"For the month of December [2000], the spot wellhead price averaged an unheard of $8.36 per thousand cubic feet. Never have spot gas prices at the wellhead been this high for such a sustained period of time".. the predominant reason for these sustained high gas prices was, and still is, uneasiness about the winter supply situation. For much of the summer, low levels of underground storage raised concerns about the availability of winter supplies. Now that the winter has really started, the most severe assumptions about low storage levels have come true. The low levels of gas storage have put the spot market in an extremely volatile positionUnderground working gas storage levels are currently 31 percent below year-ago levels and a remarkable 23 percent below the previous 5-year average (emphasis added)." EIA Short–Term Energy Outlook, January 2001.

"The duration of these high gas prices is unprecedented" it will be a while (if ever) before prices at the wellhead return to the low level of $2.00 per thousand cubic feet".One factor keeping those prices relatively high is, once again, concern over the adequacy of injections into underground storage. The gas supply situation this injection season bears close monitoring" (emphasis added)." EIA Short Term Energy Outlook, April 2001

"Underground storage levels set records last month." For the end of November [2001], the storage level is estimated to have been about 29 percent above last year's level. We project that natural gas wellhead prices will generally stay below $2.40 per thousand cubic feet through the winter." EIA Short–Term Energy Outlook, December 2001.

The shortage in underground storage was perhaps the dominant causal factor in the spike in gas prices, the market instability, and the ephemeral energy crisis of 2001. Given the language included in the 1999 Energy Policy and Conservation Act (EPCA), that emphasized reserves, combined with the importance of reserves for long-term supply as well as short-term supplies for injection into underground in-

ventories, we recommend that the resource assessments include an analysis of the location and accessibility of gas and oil reserves.

Resource Assessments Should Rely on USGS Data.

Section 604 of the Energy Policy and Conservation Act Amendments of 2000 requires an inventory that identifies United States Geological Survey reserve estimates of the oil and gas resources. While we recommend the use of USGS data, it is important to note that there is considerable uncertainty involved when making estimates of the undiscovered quantities of oil. There is geologic uncertainty as to whether any oil-gas even exists, and there is market uncertainty with respect to future oil prices. To stress the significance of this uncertainty, the USGS describes quantities of oil in terms of probabilities (Figure 4). Quantities of oil that might be economically recoverable are stated in terms of the 95th percentile (19 in 20), expected mean value, and 5th percentile (one in 20) probabilities of exceeding a stated quantity. Using Figure 4 as example, there is a 95% chance of at least volume V1 of economically recoverable oil, a 50% chance of at least volume V3, and a 5% chance of at least V2 of economically recoverable oil. We believe that the USGS expected mean estimates provide the best, unbiased point estimate of the expected value of undiscovered oil and gas resources. [4]

While we support the use of mean estimates, we express considerable skepticism when it comes to quantities of undiscovered oil or gas estimated with only a 5-percent probability. Estimates with just a 5-percent probability can be expected to be wrong 19 out of 20 times. Predictions that are wrong 19 out of 20 times are rarely relevant in policy debates. To emphasize this point, consider the following example. If an environmental group ran a computer model that estimated global temperatures would increase 15 degrees in the next 10 years if we keep emitting carbon dioxide at current rates, but the model prediction was wrong 19 out of 20 times—would anyone take the estimate seriously? Would decision-makers, scientists, or the press give the estimate any credibility? Pro-drilling forces would certainly scoff at the scare tactics and pseudo-science behind a dire environmental prediction that may be correct only 5% of the time. With this in mind, we believe that quantities of oil and gas, estimated with just a 5-percent probability, should be heavily discounted, if not ignored, by decision-makers

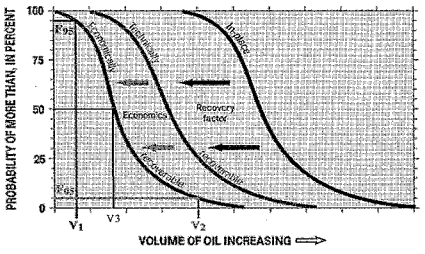


Figure 4. Oil volumes and probabilities for estimating undiscovered quantities in the Arctic Refuge. Oil in place is the amount of petroleum in the ground without regard to whether the oil can be technically recovered. Technically recoverable oil represents the quantity of oil in place that is recoverable using current technology without regard to costs or profits. Economically recoverable oil is the quantity of technically recoverable oil that can be recovered based on exploration, production and transportation costs, plus a 12 percent profit margin. There is a 95% chance of at least volume V1 of economically recoverable oil, a 50% chance of at least volume V3, and a 5% chance of at least V2 of economically recoverable oil. Source: Adapted from USGS 2001.

Resource Assessments should be based on the Amount of Oil and Gas Economically Recoverable.

We believe that economically recoverable amount of oil and gas—not the technically recoverable amount—is the correct measure of the opportunity costs of protecting the environment. The concept of opportunity costs is the appropriate construct for valuing both benefits and costs of public policies. Opportunity costs equal the net benefits foregone as a consequence of the policy or action. One of the common mistakes made when evaluating regulations or decisions to limit access, is the use of gross revenues when estimating opportunity costs, rather than net revenues. The opportunity costs of leasing stipulations should equal the net benefits of the oil or gas foregone. If the full cost of extracting a resource is greater than market price, the net benefits are negative, the resource is not an economic resource, and there are no opportunity costs from protecting the environment.

[4] The mean is technically an average for the mathematically derived probability distribution that is generally close to the 50-percent probability. However, the statistical procedure used to arrive at mean estimates tends to produce a figure that is greater than one estimated with a 50 percent probability (Economic Associates, Inc. 1983).

Technically recoverable oil represents the quantity of oil in place that is recoverable using current technology but without regard to costs or profits. Economically recoverable oil as estimated by the USGS (2001) is the quantity of technically recoverable oil that can be recovered based on exploration, production and transportation costs, plus a 12 percent profit margin. The Congressional Research Service concludes that a useful analysis for policy purposes should focus on estimates of oil resources that are economically recoverable (Corn, Gelb and Baldwin 2001).[5] Virtually every report on gas supply over the last 20 years has reported results in terms of economically recoverable resources (Environmental Law Institute 1999). Since policymakers should be concerned about the actual impacts—not the hypothetical impacts—from lease stipulations, economically recoverable resources, as estimated by USGS scientists, are the policy-relevant measure and should be the basis for the EPCA studies.[6]

When economic criteria are considered the amount of oil and gas actually recoverable drops significantly (USGS 1998). Within the Rocky Mountains and Northern Great Plains, 81 percent of the undiscovered gas is in unconventional deposits. Of this, the USGS estimates that only 8 and 4 percent is economically viable at $3.34 and $2 per mcf, respectively (RAND 2002)—underscoring the drop in accessible resources due solely to financial constraints on production. In the Green River study area, 90 percent of the technically recoverable gas is continuous-type, tight gas (DOE, Table 2, p. 10, 2001). The high costs associated with extracting continuous-type gas from low permeability geologic strata result in only a small percent of the technically recoverable gas being profitable for a company to extract. USGS scientists (1998) estimate that between 7 and 15 percent of technically recoverable, continuous-type, tight gas in the lower 48 is economically recoverable. The actual impacts on gas supplies from lease stipulations are therefore much less than estimated in the DOE Green River report.

Similar financial constraints apply to coal bed methane (CBM). Papers presented at a recent coalbed methane conference indicated that CBM below 5000 feet, while technically recoverable, is not economical to extract. CBM located 10,000 feet underneath a roadless area, for example, would therefore have an opportunity cost of zero—even without roadless area protection, no one would drill for the CBM as it is not an economic resource. In such cases, roadless area protection would not be the binding constraint on production; the binding constraint is the financial cost associated with extracting gas 10,000 feet below the surface.

We remain concerned that if the EPCA access studies continue to ignore economic constraints on production they will overestimate the quantity of oil or gas potentially off-limit, and, therefore, overestimate the opportunity costs associated with lease stipulations that protect the environment. To reiterate, if the gas is not economically feasible to extract, there are no adverse impacts on gas supply or prices from lease stipulations designed to protect wildlife, archeological sites, recreation sites and other public resources. The use of technically recoverable oil-gas rather than economically recoverable, is similar to incorrect use of gross revenues rather than net revenues when evaluating the opportunity costs of policies. It is for these reasons that we recommend resource assessments be based on economically recoverable oil and gas, not technically recoverable. When estimating economically recoverable oil and gas, market price is a key factor. To account for the economic uncertainty inherent in price forecasts, we recommend using the USGS high and low expected mean estimate of oil and gas that is economically recoverable.[7]

Resource Assessments should fully account for the Non-market Costs Associated with Resource Extraction.

The USGS economic analysis for the lower 48 only includes the financial costs of oil and gas production, including items such as the direct costs of exploration, development, and production. Not included in the USGS calculus are non-market costs such as the off-site ecological costs and cumulative negative environmental impacts that might result from drilling. The USGS economically recoverable analysis more closely resembles a financial analysis than an economic analysis. A financial analysis only examines costs and benefits as measured by market price; it is the view-

[5] Corn, M.L., B.A. Gelb and P. Baldwin. 2001. The Arctic National Wildlife Refuge: The Next Chapter. Congressional Research Service. Updated August 1, 2001

[6] In fact we believe that EPCA requires economics to be considered. Section 604 of the Energy Policy and Conservation Act Amendments of 2000 is titled Scientific Inventory of Oil and Gas Reserves. Section 604 requires an inventory that identifies United States Geological Survey reserve estimates of the oil and gas resources underlying these (federal) lands. Reserves are by definition economically feasible to recover.

[7] Economists at the USGS estimated economically recoverable resources using two price scenarios ($18 and $30/barrel of oil, $2.00 and $3.34.tcf of gas—all prices in 1996 dollars).

point of private industry and is more concerned with profits or losses. In contrast, an economic analysis of benefits and costs must account for non-market benefits and costs, as well as those more readily observed and measured in market prices. An economic analysis is conducted from the viewpoint of society, which should also be the viewpoint of politicians and managers of the public estate.

While many non-market costs are difficult to estimate, academic and Federal agency economists have made great advances in developing methods to value non-market costs (e.g. erosion, noxious weeds, pollution) and benefits (biodiversity conservation, ecosystem services, passive-use; Morton 2001)[8]. Many heretofore-unquantifiable wildland benefits and costs are now quantifiable and available to agency officials responsible for developing the policies and procedures for guiding public land management. We therefore recommend that the resource assessment include full consideration of these costs. RAND (2002) recommendation for utilizing spatial indices of areas with vulnerable environments is a creative technique and, at least on the surface, has the potential to be an excellent method for internalizing the difficult-to-quantify, non-market environmental costs associated with energy development. The development of an appropriate environmental vulnerability index based on, for example riparian areas, steep slopes, archeological sites, critical habitat, roadless areas, wilderness study areas, etc., will be an important factor in the success of the methods proposed.

We also encourage the USGS to internalize non-market costs into future cost functions developed for estimating economically recoverable resources. If the economic analysis fully accounted for the non-market costs associated with oil and gas extraction, the quantities of oil and gas estimated to be economically recoverable would be less than reported by USGS scientists.

Public Land Agencies Should Consider the Socio–Economic Costs Associated with Resource Extraction.

While in past testimony we have focused on the environmental and ecological costs from oil and gas production (Morton 2001), here we would like to focus on the costs to communities from accelerated resource extraction. An historic emphasis on resource extraction industries has resulted in repetitious cycles of socio-economic distress for rural communities in the west. However, in the last 15 years, the economies of the Rocky Mountain states have diversified and are not dependent on resource extraction. For many of these states and communities, service jobs, retirees, recreation and hunting are the mainstays of the economy. In the new economy, public lands have an indirect role in attracting non-recreational businesses and retirees. There is a growing body of literature suggesting that the future diversification of rural western economies is dependent on the ecological and amenity services provided by public lands in the west (Power 1996, Rasker 1995, Haynes and Horne 1997). These services (e.g. watershed protection, wildlife habitat, and scenic vistas) improve the quality of life, which in turn attracts new businesses and capital to rural communities. Public lands in the west represent natural assets that provide communities with a comparative advantage over other rural areas in diversifying their economies. As such, it is important to recognize and analyze the potential negative impacts of oil and gas exploration on the service and recreation industries, as well as on retirees and other households with investment income.

Past research indicates significant social costs (e.g. seasonal employment, higher unemployment rates) associated with economic specialization and dependency on resource extractive industries. In essence, resource extractive communities have an inherent economic instability associated with them. This instability, in income and employment, for example, is a result of laborsaving technological improvements, business cycles sensitive to interest rates and housing starts, and fluctuations in world resource markets—macroeconomic forces outside local control.

Economic instability is of concern to community leaders because if a local economy is unstable, economic development plans are more likely to fail. The economic instability created in the "boom and bust" economies associated with resource extraction increases the risk associated with capital investment in linked industries. As such, resource specialization and the resulting economic instability can prevent the formation of forward and backward economic linkages in the local and regional economy and can negatively impact workers.

Resource extractive workers tend to get stuck in a vicious cycle of relatively high paying jobs with frequent layoffs and unemployment. This cycle is what Freudenburg (1992), a sociologist, calls the "intermittent positive reinforcement re-

[8] Morton, P. 2001. Testimony before the Subcommittee on Forests and Public Land Management Committee on Energy and Natural Resources, United States Senate, April 26, 2001.

gime;" one of the most effective of all behavioral reinforcements (Freudenburg and Gramling 1994)

While resource extractive workers develop high skills, such skills are not readily transferable to other jobs and the workers become overspecialized (Freudenburg and Gramling, 1994). Investment in education and job retraining is low because "the potential return on their investment in their education is either too low or too uncertain to justify sacrifice (Humphrey et al. 1993). The resultant pattern of "rational under-investment" in the development of skill and other forms of human capital can result in reduced economic competitiveness in resource-dependent and specialized communities.

The current emphasis on oil and gas exploration is pushing rural communities into another boom-bust cycle, and there are indications that the bust is already here. Between November 2001 and February 2002, New Mexico lost 900 jobs in oil and gas industry (New Mexico Department of Labor 2002). In Wyoming, over 1500 workers in oil and gas extraction lost their job between September 2001 and February 2002 (Wyoming Department of Employment Research and Planning 2002). The primary cause of the employment bust is the significant drop in gas prices over the last year.

The current boom-bust cycle has also generated significant costs to communities in the Powder River Basin of Wyoming—costs that must be considered by public agencies rapidly promoting energy development. Many landowners are spending thousands of dollars on attorneys in order to negotiate a surface damage agreement to protect their property (i.e. the split estate problem). Other landowners have seen dramatic declines in property values.[9] The City of Gillete has experienced a 12 to 15 percent increase in truck traffic plus a 26 percent increase in traffic violations between 1999 and 2000 (Pederson Planning Consultants 2001). As a result, the expected life of city streets has decreased, while road operation and maintenance costs have increased. Dust from poorly constructed access roads causes health problems with horses, reduces the grass available for cattle, and negatively impacts air quality and visibility. County officials and residents area concerned that they will have to pay for clean up and restorations costs as the bonds posted by CBM companies for plugging and abandoning a well are inadequate.

As a result of recent coalbed methane boom, Campbell County has seen an increase in larceny, traffic accidents, destruction of private property, family violence, and child abuse—resulting in the county spending money to add 36 cells to its existing jail. The fire department has seen a 40 percent increase in emergency calls between 1997 and 2000 (Pederson Planning Consultants 2001). Similar trends have occurred in other counties in the Powder River Basin. There has also been a shift in the labor force. County workers have left for CBM jobs, resulting in instability in the labor force and making it more difficult to hire public workers (e.g. policemen, firemen) at a time where the counties and cities are stretched thin to handle the increased work load. The accelerated energy development has left many counties and communities unable to pay for or finance the increase in public service costs. We have every reason to believe that similar costs and burdens will be placed on other communities where public and private land is threatened by energy development. The socio-economic risks and costs associated with energy development, while perhaps beyond the scope of EPCA, should be acknowledged as part of the NEPA process involved with current energy development in the west.

Environmental Stipulations in Oil and Gas Leases Protect Public Resources.

While recognizing that stipulations have the potential to reduce access to oil and gas, it is important to recognize the benefits of the environmental stipulations. Public and scientific concerns for protecting sensitive lands and resources are the justification for including environmental protection stipulations in drilling leases on public land. These stipulations are designed by agency professionals to protect multiple public resources, including water quality, critical winter range for elk and antelope, sage grouse leks, archeological sites, and recreation sites. Seasonal closures, necessary to protect raptor nest sites, elk populations, and the quality of the outdoor recreation experience, may slow down the rate of gas exploitation but protect the wildlife and other multiple uses under which public land is managed, as well as the quality of life for local residents. Such protection is warranted economically, as wa-

[9] This is particularly true on the western side of the Basin, near Sheridan and Buffalo, where land values are based not on the agricultural values but on scenery and wildlife values (Jill Morrison, personal communication). One ranch, a high dollar ranch and hunting retreat, went up for sale for around $9 million. The ranch was under contract for purchase, but the buyer found out the minerals were leased and slated for CBM development. The buyer wanted to back out, but the seller agreed to a $3 million dollar reduction in the price and the buyer purchased the ranch for about $6million.

tershed protection, hunting, fishing, and recreation generate significantly more economic benefits to all Americans, including affected residents and businesses in the Rocky Mountain Region, than do oil and gas extraction. Legislative intent and public sentiment indicate that public lands should not be for the exclusive use of the oil and gas industries and that managers must attempt to balance the many uses that occur on public land. Leases with environmental protection stipulations help internalize the environmental and ecological costs associated with oil and gas extraction by protecting other multiple uses enjoyed by the public.

Resource Assessments Should Include the Potential Access Available with Directional Drilling.

The Green River EPCA study utilized a directional drilling distance of just 0.25 mile (1/4 mile) when examining access to resources, even though industry officials have repeatedly asserted that contemporary drilling technology enables operators to reach oil and gas resources at considerable distances from a drilling site.[10] For example, the National Petroleum Council (1999, page 15) states that "extended reach drilling allow access to resources 5 to 6 miles from the drill site". In addition, a 1999 DOE report titled "Environmental benefits of advanced oil and gas exploration and production technology" states that "resources" can now be contacted and produced without disrupting surface features above them" (page 13). We recommend that the EPCA studies assume a slant drilling distance that is more consistent with current technology and industry statements regarding the efficacy of, and advances in, slant drilling. For example, a 3–4 mile slant drilling distance would be reasonable to analyze.[11]

Resource Assessments Should Consider the Potential to Increase Access with Future Technology.

Technological improvements are often cited as the reason that predicted costs of compliance often turn out to be less than actual costs (OTA 1995). Trends in technological improvements should be incorporated into the resource assessment because technological improvements will, in general, increase access and reduce the amount of oil or gas estimated to be inaccessible with today's technology. History has shown that advances in drilling technology, such as remote sensing methods, have increased industry's ability to access resources in an environmentally friendly manner. Advances in remote sensing technology, for example, will improve the accuracy of drilling and will make slant drilling economically feasible from greater and greater distances, perhaps 6–10 miles or more.

Advances in drilling technology (e.g. improved drill bits) will also reduce drill times, reducing any impact seasonal wildlife stipulations may have on the ability of industry to access resources. For example, a 15,000-foot well in Oklahoma takes about 39 days to drill, a decrease from 80 days in 1970 (DOE 1999). Technological advances will reduce the quantity of oil and gas estimated to be inaccessible due to current leasing stipulations. We therefore recommend that the EPCA studies include a sensitivity analysis of the increasing access to resources on public land that results from technological innovations by the oil and gas industry. Information on the marginal increase in accessible resources from advances in technology will provide industry an incentive for investing in such technology.

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[10] Based on a discussion with BLM officials, the 0.25 mile drilling distance used in the Green River study was selected as being the distance that is feasible for industry to drill. The dominating factor in determining the feasibility of slant drilling is economics, as slant drilling can be expensive. The consideration of economic factors in determining the feasible distance for slant drilling underscores the need to also include economic factors when estimating oil and gas resources affected by lease stipulations. While there might be significant oil and gas resources in the Green River Basin, if they are not economically feasible to extract, they should not be considered inaccessible due to leasing stipulations. The implicit inclusion of economic factors when determining the feasibility of slant drilling distances is inconsistent with the exclusion of economic factors when estimating the feasibility of recovering resources. These methodological inconsistencies must be addressed in order to improve the reliability of the findings in future EPCA reports.

[11] With over 400,000 miles of road on the national forests alone and a backlog of over $8 billion dollar in road maintenance, lack of access to oil and gas on public lands is not really an issue. On average, the annual maintenance cost of a mile of road is about $1,500 per mile (USDA FS 1999). Each new mile of road added to the FS transportation system competes for limited road maintenance funding, as Congressional funding is less than 20% of the funding necessary to maintain the existing road infrastructure. One must seriously question the wisdom of building more roads when current roads can't be maintained, and each year's unmet maintenance needs increase the backlog as roads deteriorate and the costs of repair increase over time.

Resource Assessments Must Consider Cumulative Impacts and the "Diseconomies of Scale."

When examining the economically viable resource, it is important to recognize the cumulative negative impacts from increasing the scale of production. While increasing the scale of production typically decreases the financial costs to a producer (i.e. economies of scale), larger scale projects will, in general, increase the non-market economic and community costs—resulting in what we will call the "diseconomies of scale". As a result, the socio-economic and environmental constraints on the scale of oil and gas production will increase costs and may limit full development of technically recoverable resources.

While oil and gas development on a small scale may have limited negative impact on communities and ecosystems, as the scale of production increases, the ability of those systems to assimilate the impacts is jeopardized. For example, as the scale of coalbed methane increased in the Powder River Basin of Wyoming, the increase in traffic, crime and immigrants overwhelmed the capacity and budgets of communities and counties for handling these problems. While the CBM may be financially recoverable, local community concerns over the cumulative negative impacts from future production will increase the cost and may prevent the development from actually occurring.

Similarly, the cumulative negative impacts of CBM production on clean air and clean water may be a constraining factor on the scale of production—irrespective of whether the CBM is financially or technically feasible to extract. The amount of CBM wells drilled in Wyoming have increased dramatically (Figure 5). As a result, the amount of water discharged from CBM wells in Wyoming has skyrocketed in recent years, increasing from approximately 98 million gallons (300 acre feet) per year in 1992, to 5.5 billion gallons (17,000 acre feet) per year in 1999 (Wyoming State Engineer's Office cited in Darin 2000). The water discharged from oil and gas wells is highly saline with a very high sodium absorption ratio (SAR)—a ratio that affects how water interacts with soil. Water with a high SAR can permanently change chemical composition of soils, reducing water permeability and thereby decreasing native plant and irrigated crop productivity. To be sustainable and to maintain water quality, the increase in SAR water should not exceed the SAR assimilative capacity of the regional river systems. As the scale of CBM production increases, it is more likely that the cumulative quantities of SAR will exceed the assimilative capacity of regional watersheds.

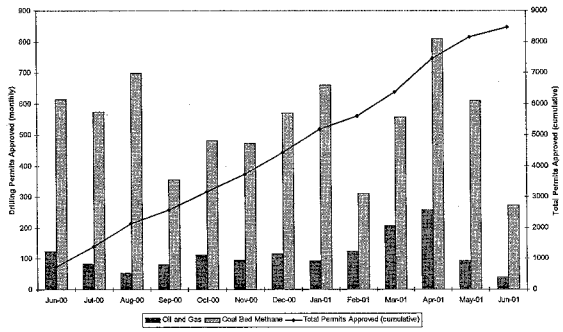

Figure 5. The Dramatic Increase in Oil and Gas Permits Approved in Wyoming (June 2000 – June 2001). Source: Wyoming Oil and Gas Conservation Commission, 2001

Similar arguments can be made with respect to the negative impacts of CBM production on air quality. Based on an analysis by Bob Yunke of the Environmental Defense Fund (2002), the total emissions associated with developing the more than 50,000 wells expected in the Powder River will exceed Clean Air Act limits in the surrounding Class I airsheds (Northern Cheyenne Reservation in Montana and the Badlands National Park in South Dakota). As a result of CBM development in the Powder River, there could be a 60 percent decrease in visibility in the Badlands on peak air pollution day. The loss of clear skies will reduce the quality of life for local residents and decrease the quality of the recreational experiences in nearby wilderness areas and national parks—all of which will translate to negative economic impacts on local communities.

In summary, the assimilative capacity of communities and ecosystems represent constraints on oil and gas production that may limit future production, even though the oil-gas may be financially feasible for a corporation to produce. Cumulative impacts and constraints on the scale of production should therefore be considered when assessing economically viable resource,

Conclusions

Based on analysis of USGS data, it is clear that drilling public wildlands in the west will do little to affect our energy future. Public lands provide greater benefits to society when left in their wild and roadless condition for current and future generations to enjoy. The marginal benefits from wildland conservation are, in most cases, much greater than the marginal costs in the form of the undiscovered, economically recoverable energy resources foregone.

The current fixation on access to undiscovered resources in remote wildlands overestimates the importance of undiscovered resources in reducing market instability and reducing the energy prices paid by consumers. Decision-makers concerned about high energy prices and price volatility (the main components of the energy "crisis") would be better served by focusing on transporting gas from existing reserves into short-term storage. In addition, requiring industry to maintain a higher minimum underground storage level will reduce price volatility and the cause of high energy costs for consumers and businesses. In contrast, drilling public wildlands will do little to address the root causes of the 2001 "energy crisis", nor will it reduce the energy costs for families—despite claims to the contrary made by industry officials.

Regardless of whether there is high access to resources or high investment in drilling technology, the downward trend in America's crude oil production will continue. In other words, we have already discovered the best reserves America had to offer. Of the 4.6 million oil wells worldwide, 3.4 million have been drilled in the U.S and a majority of America's wells were dry wells. Why subsidize the drilling of more dry wells? Rather than propping up old industries, increasing profit margins for corporations, and sacrificing America's remaining wildlands, taxpayer subsidies would be far better spent promoting new markets in alternative energy, efficiency and conservation. The bottom line is that the first country to wean itself from oil wins.

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[Responses to questions submitted for the record by Mr. Morton follow:]

Oversight Hearing on Oil and Gas Resource Assessment Methodology

APRIL 18, 2002

FOLLOW-UP QUESTIONS FROM CHAIRMAN CUBIN

PETE MORTON, PH.D.

THE WILDERNESS SOCIETY

1). You have criticized the DOE Green River Basin assessment as biased because of gas industry participation. How could a useful assessment of oil and gas resources be done without the participation of those who study and find America's oil and gas fields?

A useful, unbiased assessment could be completed by utilizing the team of USGS scientists, including Emil Attanasi at the USGS, which completed the recent USGS Oil and Gas Assessment for the U.S. Of course, such studies should be critically reviewed by interested parties, including government and university scientists, the energy industry, and the environmental community.

For the most part, I have no quarrel with the energy industry's participation in such studies. I do remain concerned with the practice of letting the energy industry

dominate such studies, often to the absolute exclusion of input from other stakeholders. The energy industry is not the only entity with knowledge of resources on our public lands. And the energy industry is the LAST entity that is likely to offer an impartial assessment of the regulations governing energy development on public lands. Nor does the energy industry have adequate expertise on the non-energy resources—wildlife, fishing, recreation, watershed protection, or scenic beauty—that American's value from their public lands. Oil and gas are not the only, nor even the most important, values on America's public lands. Any analysis that excludes full consideration of these other broad public values is sure to be biased in industry's favor.

With respect to the Green River Basin assessment, the lack of critical review of the assumptions, methods and parameters used in the study resulted in a biased report that overestimated the amount of economically recoverable gas made inaccessible due to environmental protection stipulations included in oil and gas leases.

2) Do you ever plan to release any part except the Executive Summary, of the report entitled "The Department of Energy's "Federal Lands Analysis Natural Gas Assessment : A Case of Expediency over Science?" If so, when?

We were hoping to have this report published by now, but as you know, the last year has been extremely busy for those concerned with the health of the land, and we are behind in publishing the full report. We fully expect to include the text from the referenced study in an upcoming Wilderness Society report on oil and gas in the West. We hope to finish this report by the end of the summer and will be glad to send you a copy. Thank you for your interest in our research.

Ms. CUBIN. We certainly thank you for your testimony.

Our next witness will be Ray Seegmiller, Chairman, President, and Chief Executive Officer, testifying on behalf of Cabot Oil and Gas Corporation, and the Domestic Petroleum Council. Mr. Seegmiller.

STATEMENT OF RAY SEEGMILLER, CHAIRMAN AND CHIEF EXECUTIVE OFFICER, CABOT OIL AND GAS CORPORATION, AND PAST CHAIRMAN AND DIRECTOR, DOMESTIC PETROLEUM COUNCIL

Mr. SEEGMILLER. Thank you, Madam Chairman. I appreciate the opportunity to testify before the Subcommittee today. I am Ray Seegmiller, Chairman and Chief Executive Officer of Cabot Oil and Gas. I am extremely pleased to be with you today to address a critical issue which, unfortunately, is often misunderstood by Members of Congress and Administration officials alike. It is the issue of how Cabot and hundreds of other companies like Cabot make decisions that determine the supply of oil and natural gas to fuel our economy, generate our power and heat our homes. In another way, it is a question of how we put dollars at risk and decide whether or where to explore and find our energy sources for the future.

Today I speak not only for Cabot, but also for the Domestic Petroleum Council, an association of the producing community's 22 largest and most active independent exploration companies. And at this time, I would like to request that my full written statement be entered into the record. Thank you.

Continuing analysis of our domestic energy resource base, especially natural gas and the factors that restrict access to it, are extremely important in helping policymakers understand the direction we need to be moving to supply future demand.

The studies of the National Petroleum Council, as well as ongoing studies by several executive branch agencies, are very helpful to government and the general public with respect to resource assessment. Of particular use to the government and the public is

analysis of specific restrictions on exploration and production. However, we also hear hypothetical and often illogical statements that are either confusing or simply irrelevant to those of us who make our living by putting real money to work in the hope of finding real resources.

For example, statements to the effect that a large percentage of public lands are open to oil and natural gas leasing and development continually ignore the fact that only a portion of the most prospective areas may be available. Those who claim that we should not be concerned about access until we are sure that resource exploration and production will be economic, only stifle development.

Likewise, those who claim that issues regarding capital infrastructure, such as the development of pipeline and gathering system capacity, should come before resolving access issues, turn the decision-making process totally upside down.

We, the producers, must first believe with confidence that we have access to the resource, prior to tackling those down-the-line issues. Think about it, without resource access, there is no reason to resolve those other challenges. Nothing else matters, unless there is available resource to find, develop and produce.

So let me do a quick summary of how we at Cabot explore for natural gas regardless of the policy-oriented studies. As an explorer for natural gas for over a hundred years, Cabot Oil and Gas has worked with many other companies in our business. Each company's approach to the exploration of natural gas is very consistent, even though the final evaluation of potential reserves may differ drastically.

What drives exploration success is primarily good geology. By this, I mean we need to acquire as much data about an area that is economically feasible and provides a reasonable expectation of making a discovery. This requires confidence that we will have access to the acreage being studied.

Once we are confident we will have access, our geoscientists map the surface and sub-surface geology, looking for clues that suggest the presence of hydrocarbons and reservoir-quality rock. To do this, we utilize a variety of data, including: surface geological maps; remote sensing techniques; electric logs from well bores in the area; and seismic data, whether it be 2-D or 3-D. If the data is not available from outside sources, we may have to hire a contractor to do this field work, such as seismic surveys.

Almost always, we have to obtain permits to do this work, even though we have access to the area under review. Being able to acquire this data on a timely basis is very important to the economics of any such project.

On a step-by-step basis, Cabot proceeds with an exploration process as follows. And by the way, in consideration of time, I will only list them in sequence. There is more detail in my written report.

First, we do a regional geologic analysis.

Second, we map any hydro-bearing trends, like sandstones, etcetera.

Then we map the geologic structure.

Fourth, we will develop leads where we think there might be hydrocarbons present.

And next, if we feel there is a possibility of hydrocarbons, we will obviously shoot 3-D or 2-D seismic.

Once we have this data, we will integrate it into the sub-surface geology.

Then we will determine whether or not the drilling prospects are there, and second, we will rank them as to potential.

Then we determine the risk-weighted rate of return of the total prospect, including infrastructure and the transportation costs to get this product to market. This may include transportation. It may be stripping, as far as impurities, nitrogen, CO2, etcetera.

If the potential return is satisfactory in our estimation, at the expected gas prices we see for the future, we would apply for a drilling permit and would have to meet all of the environmental issues that are in that area.

And last, then, of course, we drill the well.

The cost of the first well in some of these remote areas can be very expensive. However, if the reservoir potential is perceived to be large enough, we will take that risk. Once a discovery is made, the infrastructure to get the gas to market will be put in place, if the prospect size justifies the additional cost. As in the movie "Field of Dreams"—"Build it, and they will come"—In our case, if a discovery is large enough, the infrastructure will be there and the processing plants will be there to take care of this production.

The point I want to make is that without access to the acreage, there is no reason for a company like Cabot or all of our peers to put their dollars at risk; and therefore, none of the above is possible. Cabot has followed this process in two recent cases on Federal lands where we acquired access. In each case, there could have been an argument that infrastructure did not exist and there were no assurances of an economic resource. But it was our job as a company to take that resource risk.

The first case is in the Paradox Basin in southwest Colorado. And this is an area where we have had two very successful wells, and the infrastructure, of course, was put in place. Another was in Wyoming, which was in the Wind River Basin. And that is in my written testimony.

In final conclusion, I would just like to conclude by saying that we, Cabot, and other producers, continue to do our best to apply the latest technology in the search for the nation's natural gas and oil. But we do it based on real-world information, in areas where we believe we will have access to the resource and then be able to work with the Federal, state and local governments, surface owners and users, as well as others, to ensure that what we do is environmentally sound and in our collective best interests.

Thank you very much for your attention. And I am glad to be here to answer any questions.

[The prepared statement of Mr. Seegmiller follows:]

Statement of Ray Seegmiller, Chairman and Chief Executive Officer, Cabot Oil & Gas Corporation, and Past Chairman and Director, Domestic Petroleum Council

Madam Chairman and Members of the Subcommittee, my name is Ray Seegmiller and I am the Chairman and Chief Executive Officer of Cabot Oil & Gas Corporation.

I'm extremely pleased to be with you today to address a critical issue which, unfortunately, is often misunderstood by members of Congress and Administration

officials alike. It is the issue of how Cabot and the hundreds of other companies like Cabot, make decisions, which determine the supply of oil and natural gas to fuel our economy, generate our power and heat our homes.

In another way, it is a question of how we decide whether or where to explore with the hope of finding energy supplies.

Today, I speak not only for Cabot, but also for the Domestic Petroleum Council, an association of the producing community's 22 largest and most active independent exploration companies.

Continuing analysis of our domestic energy resource base, especially natural gas and the factors which restrict access to it, are extremely important in helping policymakers understand the direction we need to be moving to supply future demand.

The studies of the National Petroleum Council as well as ongoing studies by several Executive Branch agencies are very helpful to government and the general public with respect to resource assessments. Of particular use to the government and the public is analysis of specific restrictions on exploration and production. However, we also hear hypothetical and often illogical statements that are either confusing or simply irrelevant to those of us who make a living by putting at risk real dollars in the hope of finding real resources.

For example, statements to the effect that a large percentage of public lands are open to oil and natural gas leasing and development continually ignore the fact that only a portion of the most prospective areas may be available. Those who claim that we should not be concerned about access until we are sure that resource exploration and production will be economic; will only stifle development. Likewise, those who claim that issues regarding capital infrastructure, such as development of pipeline and gathering system capacity, should come before resolving access issues turn the decision making process totally upside-down.

We, the producers, must first believe, with confidence that we can access the resource prior to tackling those "down the line" issues. Think about it, without resource access there is no reason to resolve those other challenges. Nothing else matters unless there is an available resource to find, develop, and produce.

So, let me now do a quick summary of how we at Cabot Oil & Gas Corporation explore for natural gas and oil, regardless of the policy-oriented studies.

Cabot Oil & Gas Corporation is a domestic explorer and producer of natural gas with over 1.2 Tcfe of reserves. The Company's four core areas are the onshore Gulf Coast, Appalachia, the Mid–Continent and the Rocky Mountains. In the Rocky Mountains we currently have over 500 natural gas wells, most of which are in Wyoming and we drill between 20–50 wells per year in that area. Mostly on Federal lands in western Wyoming.

As an explorer for natural gas reserves for over 100 years Cabot Oil & Gas has worked with many of the other companies in our business. Each company's approach to the exploration for natural gas is very consistent even though the final evaluation of potential reserves may differ.

What drives exploration success is primarily good geology. By this, I mean you need to acquire as much data about an area that is economically feasible and provides a reasonable expectation of making a discovery. This requires our confidence that we will have access to the acreage being studied.

Once we are confident we will have access, our geoscientists map the surface and sub-surface geology looking for clues that suggest the presence of hydrocarbons in reservoir quality rocks. To do this we utilize a variety of data including surface geologic maps, remote sensing techniques (i.e., gravity, magnetic and geochemical), electric logs from any well bores in the area and seismic data (both two dimensional and three dimensional). If the data is not available from outside sources we may have to hire contractors to do field work such as seismic surveys. Almost always we have to obtain permits to do this work even though we have access to the area under review. Being able to acquire this data on a timely basis is very important to the economics on any such project.

On a step by step basis, Cabot proceeds with an exploration project as follows:

1. Regional geologic analysis—In the area of interest and the region surrounding it what are the indications of hydrocarbon bearing formations.
2. Map the sandstone trends—Map the reservoir rock trends in the area and estimate their porosity and permeability by looking at outcrops, well bore data in the region (if any), etc. Sandstone pinchouts associated with effective seals could hold entrapped hydrocarbons.
3. Map the geologic structure—Map the simple anticlines, faults and structural trends. These could provide traps for hydrocarbon accumulation.
4. Develop lead ideas—From the previously completed data determine if there are areas that might potentially hold hydrocarbons.
5. Acquire seismic data, either 2–D or 3–D, over the potential hydrocarbon areas.

6. Map the seismic and integrate it into the subsurface geology previously prepared.
7. Determine those drilling prospects with the highest potential.
8. Determine the potential risk weighted rate of return for the total prospect including infrastructure and transportation costs.
9. If potential return is satisfactory at expected gas prices—apply for a drilling permit and comply with all environmental issues.
10. Drill the first well.

The cost of the first well in certain areas can be very expensive however, if the reservoir potential is perceived to be large enough we will take that risk. Once a discovery is made, the infrastructure to get the gas to market will be put in place if the prospect size justifies the additional costs. As in the movie Field of Dreams—"Build it and they will come". In this case if the discovery is large enough the infrastructure will come.

The point I want to make is that without access to the acreage none of the above is possible.

Cabot has followed this process in two recent cases on Federal lands where we acquired access. In each case there could have been an argument that infrastructure did not exist and there were no assurances of an economic resource. But, it's our job to take the resource risks, so the first case in the Paradox basin of southwest Colorado with our partners, we prepared the regional geologic analysis, followed with seismic acquisition, which resulted in the drilling of two significant producing wells, with more to follow. These discoveries more than justified the pipeline extension to get the gas to market. In another area we drilled a dry hole and we are now reviewing our geology using the new data from this well. Cabot alone has spent over $8 million in seismic and drilling on this 300,000 acre play so far.

In the Wind River Basin of central Wyoming, Cabot is currently preparing to drill the second wildcat well on a 60,000-acre block where we followed this same procedure. We did our basic homework in evaluating all the available surface and subsurface data, shot over 100 square miles of three dimensional seismic and then mapped several structural prospects. The well on the first prospect was dry. We will drill the second prospect his fall, which is a large structural trap that could hold substantial reserves. To date, Cabot alone has spent close to $3 million for acreage, seismic and well costs.

Finally, let me add a footnote before concluding my remarks. Despite the best efforts of the exploration and production sector or the government, our projections are often conservative when it comes to energy resources. We'll continue to be conservative because of the risks involved, but consider just two examples of the national benefit from companies that were willing to take the risk, and applying the latest technology, despite conservative—some would say pessimistic—resource estimates.

The initial reserve estimate for Alaska's Prudhoe Bay field, North America's largest oil field, was 9.6 billion barrels of technically recoverable oil based on a recovery factor of about 40 per cent. This field has now produced more than the original estimate and eventual recovery is now expected to exceed 65 per cent, or 15 billion barrels.

In the Green River Basin of Wyoming, a fledgling McMurry Oil Company managed to "bring to production" in 1992 two small wells that were more than thirty miles from the nearest gathering line. That field, the Jonah Field, now produces in excess of 700,000 mcf/day, enough gas to heat most of southern California on a cold winter day. During the first year of production, there was one summer month where the mainline price for gas was $1.14/MMBtu (meaning a wellhead netback price of less than $.75/MMBtu), but with improved pricing and strong production the area has been very economic. The average price for gas in the Green River Basin in 2001 was $3.65/MMBtu

In conclusion, we'll continue to do our best to apply the latest technology in the search for the nation's natural gas and oil. But we'll do it based on real-world information in areas where we believe we'll be able to access the resource and then be able to work with the Federal, state and local governments, surface owners and users as well as others to ensure that what we do is environmentally sound and in our collective best interests.

Thank you for your attention. I'd be glad to answer any questions you may have.

[Responses to questions submitted for the record by Mr. Seegmiller follow:]

MAY 1, 2002

Ms. Daisy Minter
Committee on Resources
Subcommittee on Energy & Mineral Resources
U.S. House of Representatives
1626 Longworth House Office Building
Washington, D.C. 20515

Dear Ms. Minter,

The letter is being submitted as a result of the additional questions outlined in Chairman Cubin's letter dated April 23, 2002 from members of the Subcommittee on Energy & Mineral Resources. The questions are in the order submitted with the responses requested for the hearing record.

Questions from the Majority

1. Some have criticized the NPC study as biased towards the oil industry. What interest does the industry have in inflating oil and gas resources in a regional assessment? Can a useful regional oil and gas assessment be made without the participation of the industry?

The energy industry does not have an interest in inflating resource estimates. One could make the argument that it has an interest in presenting rather conservative estimates of the resource base. Dismal projections of resource estimates would make for easier analytical argument for increased access.

It should be noted that the NPC Study was not the most optimistic resources base assessment at the time of its publication. The 2000 GRI Baseline Study, released several months after the NPC Study, estimated the Lower 48 resource base at 1,748 TCF versus the 1,466 TCF NPC estimate.

Without industry's insights into exploration and production methodology, we believe that an objective assessment would be very difficult.

2a. Mr. Seegmiller, as an oil and gas operator in the Rocky Mountains, would you agree with Mr. Goerold's and Mr. Morton's criticism of the use of ′ mile directional drilling limit for the Green River Basin Gas Study when examining access to gas resources under lands with a "no surface occupancy" stipulation?

As Dr. William Whitsitt stated in his follow-up letter to you dated April 24, 2002, "While it is true that industry has demonstrated that it can directionally drill 5 or 6 miles, that does no mean it can be done everywhere. And it is not a viable practice in exploration settings, especially in the Rockies."

The geology of the Rockies is very complex and principally "hard rock" country. Requiring directional drilling in excess of ′ mile would in most cases make any potential drilling uneconomic.

2b. Mr. Morton further states that the EPCA studies should assume a directional drilling distance that is more realistic, 4 to 5 miles. Given your considerable experience, is this reasonable at the present time or in the, say next 10 years given the economics of exploring and developing Rocky Mountain gas deposits? Do you know of any areas where 6-mile directional drilling is economic?

In Alaska there is up to six-mile directional drilling. However, this is not the case in the Rockies for the following reasons:

a. The geology of the Rockies is more complex than the northern slope of Alaska. In fact when you refer to the Rockies, you are talking about a very heterogeneous environment (from a geological standpoint) vis-a-vis Alaska. The geology of the Green River Basin will be different from the Wind River Basin, which will be different from the Powder River Basin and so on. As an illustration of the geologic complexity, approximately 85% of the oil and gas resources in the Rockies are unconventional gas (on an energy-equivalent basis). Unconventional gas is much more risky to develop, thus the use of long-range directional drilling would be limited. The more complex the environment that you are drilling into, the more mitigating circumstances come up, like higher drilling costs.

b. Aside from geology, targeted reserve sizes matter also. The drilling costs of these long deviated holes, such as those in Alaska, are a lot higher than vertical holes. This is due to 1) the more complex (expensive) equipment needed and 2) penetration rates slow down. In Alaska this is acceptable because the reserve estimates per well bore are substantial. In the Rockies, extremely high reserve estimates per well bore are the exception rather than the rule.

c. While it is true that industry can directional drill 5 or 6 miles, this is not a practice in EXPLORATION settings, especially in the Rockies. The composition of the industry in the Rockies is different from Alaska. More independents and less majors, such that the tendency to use directional drilling will be less, all other things being equal, because of the higher financial risks.

3. In the Rocky Mountains, have areas that are currently restricted from oil and gas exploration always been closed to such development?

We understand that exploration activity took place for several decades in many of the areas which are now considered "off-limits" to exploration.

4. Is there any useful data available from previous oil & gas activity in areas that were previously open, but are now closed to development?

In some areas there is limited data available, but it's questionable how useful the data would be today given the technological advances of the last decade. Acquiring useful exploration data to justify the exploration risk will require open access to these areas.

5. Can you give us an example where a currently closed area of the Rockies might have developed into a significant discovery of reserves?

There has been significant interest by a number of industry participants in the Rocky Mountain front of Montana due to the significant potential for new discoveries that would provide needed fuel for our nation.

Questions from the Democrats

1. Mr. Seegmiller, what percentage of your high yield wells are adjacent to, part of, existing reserves? In your experience, are most deposits found close to known reserves or are they more "the luck of the draw?"

Historically our highest yield wells have been discoveries in new prospect areas. Non-producing reserves adjacent to producing reserves are considered in a company's reserve base as proven or probable reserves, so they are not considered new discoveries. We find new reserves through the extensive technical efforts of our geoscientists once we have access to a prospective area, not by "the luck of the draw".

2. Would you agree that when searching for new gas discoveries, the size of the minimum economically viable field is greater the farther the new discovery is from existing pipeline infrastructure?—see answer under 3.

3. And to follow-up, that in general, the minimum economic field size decreases if the gas discovery is closer to existing pipeline infrastructure?

Economics are dependent primarily on the size of a discovery. Gas and oil prices will fluctuate over time and are difficult to forecast, while pipeline infrastructure is only put in place to connect new discoveries. Thus, most significant discoveries are made in areas where there is not existing pipeline infrastructure and the nearest pipeline infrastructure must be extended to the new discovery. An operator, like ourselves, wouldn't drill a new prospect if we felt the reserve potential was not large enough to justify the extension of an existing pipeline to the new field.

4. Would not you agree with the RAND report, that proximity to pipeline infrastructure is an important factor to consider when estimating the economically viable resource?

The RAND report has it backwards; pipeline infrastructure is only put in place to new discoveries whose reserves are adequate to justify the incremental cost. Thus, if we had to wait until pipelines were extended to areas that may contain oil and gas reserves to drill the first well in a new prospect, it wouldn't happen and companies like ourselves would gradually go out of business due to the inability to replace our depleting reserve base.

I hope the above comments are useful. Should you or anyone on the subcommittee have any questions or need additional information, please contact Greg Moredock at (281) 589–4679.

Sincerely,

Ray Seegmiller
Chairman and Chief Executive Officer
Cabot Oil & Gas Corporation

Ms. CUBIN. Thank you, Mr. Seegmiller.

The last witness on panel two is ill today, and unable to make it here to testify. I am satisfied that he really can't make it. And so, without objection, his testimony will be entered into the record. And questions from the Committee can be sent to him, as well.

[The prepared statement of Mr. W. Thomas Goerold follows:]

Statement of W. Thomas Goerold, Ph.D., Resource Economist, Owner of Lookout Mountain Analysis

I am Dr. Thomas Goerold, Resource Economist and Owner of Lookout Mountain Analysis in Golden, Colorado. My firm specializes in analyzing many different policy alternatives to domestic and foreign energy and mineral issues.

I appreciate the opportunity to testify today regarding the impacts of different oil and gas resource estimates and their potential impacts on energy policy and energy security. My testimony will not concentrate so much on examining the different number estimates that may be drawn from these different assessment methodologies, but instead will look more broadly at how to best use this nation's energy policy tools to achieve energy security. My testimony examines the implications on energy policy of recognizing the increasingly finite supply of oil and gas remaining in the U.S.

The first section examines attempts by the U.S. Geological Survey (USGS) to estimate the amount of oil remaining in the U.S. and the world. After examining the distribution of U.S. and world oil and gas resources, the remainder of this testimony analyzes some of the most effective U.S. energy policies.

I would like to introduce into the record two reports that I have prepared that are particularly relevant to energy resource assessment methodologies and results; (1) Examination and Critique of ARI Report: Undiscovered Natural Gas and Petroleum Resources Beneath Inventoried Roadless and Special Designated Areas on Forest Service Lands Analysis and Results, with Additional Discussion of U.S. Geological Survey and National Petroleum Council Reports; and (2) A Brief Examination of the Adequacy of Future U.S. Natural Gas Infrastructure and Resources and The Role of Public Lands in U.S. Natural Gas Production.

USGS WORLD AND U.S. OIL AND GAS ASSESSMENT

The USGS 2000 World Oil and Gas Assessment projected that (excluding the U.S.) the world's undiscovered conventionally recoverable oil, natural gas liquids (NGL), and natural gas is about 1,634 billion barrels of oil, expressed as barrels-of-oil equivalent (BOE). This estimate is about 5 percent higher than the USGS 1994 estimate of 1,556 billion BOE. (USGS, 2000). The USGS 2000 estimate includes a 20 increase in undiscovered oil, a 130 percent rise in NGL, and a 14 percent decrease in undiscovered natural gas. The large volumes of oil, gas, and NGL from reserve growth were not previously assessed by the USGS. Including U.S. resources, the 2000 USGS estimate shows a 9.5 increase overall in billion BOE, with oil up 24 percent, NGL up 104 percent and gas down 10 percent (USGS, 2000).

Compared with their previous estimate, the 2000 USGS study shows (1) more oil and gas in the Middle East and North Africa, (2) more oil and gas in eastern South America, (3) generally less oil and gas in Mexico and China, and (4) much less gas in the Former Soviet Union (especially in the Arctic). Other Arctic areas of some basins in China, and the Alberta Basin of Canada are now expected to produce smaller amounts of gas than in previous USGS studies.

Areas with the greatest volumes of undiscovered conventional oil include the Middle East, northeast Greenland Shelf, the West Siberian and Caspian areas of the former Soviet Union, and the Niger and Congo delta areas of Africa. Newly identified areas of oil potential with no previous production history include northeast Greenland and offshore Suriname.

Areas with the greatest volumes of undiscovered conventional gas are the West Siberia Basin, Barents and Kara Seas shelves of the former Soviet Union, the Middle East, and offshore Norwegian Sea. Promising areas without current development are located in East Siberia and the Northwest Shelf of Australia.

As shown in Table 1 below, not including the U.S., the average volumes of undiscovered world resources are 649 billion barrels of oil, 4,669 Tcf of gas, and 207 billion barrels of NGL. In addition, the estimated mean additions to reserves from discovered fields are 612 billion barrels of oil, 3,305 Tcf of gas, and 42 billion barrels of NGL. About 75 percent of the world's grown conventional oil endowment and 66 percent of the world's grown gas endowment have already been discovered in the areas assessed (outside of the U.S.). Also, for these areas, 20 percent of the world's

grown conventional oil and 7 percent of the world's grown conventional gas had been produced by the end of 1995.

As of January 1, 1996, average U.S. estimates of undiscovered conventional oil are about 83 billion barrels, with reserve growth from existing fields contributing another 76 billion barrels, and known and identified reserves standing at approximately 32 billion barrels. Cumulative production to 1995 was about 171 billion barrels.

In summary, the U.S. could be expected to produce about 191 billion barrels of additional petroleum from domestic supplies. At current rates of consumption, if one assumes that all domestic consumption could be supplied by domestic oil sources it would take about 29 years to exhaust the 191 billion barrels of additional domestic oil sources. By contrast, assuming that current rates of domestic production are maintained and that oil imports will grow to satisfy increasing demand (about 2.6 billion barrels of annual oil production), it would take about 73 years to consume the 191 billion barrels of identified domestic oil. These two scenarios bracket the likely maximum amount of time that this country has before the costs of using oil exceed the benefits of consuming it.

Other studies, including at least one by the Rand Corporation, concentrate on quantifying the amount of domestic oil resources that may be economically producible. As such, these studies impart valuable information about the distribution and amounts of oil left in this country. But, the basic conclusion is nevertheless the same'the U.S. does not have enough oil and gas resources left in the ground that it can (or should) produce every barrel that it consumes. And, oil and gas imports are expected to become increasingly cheaper to consume than domestically produced energy. The larger question thus becomes, given these geological facts on the domestic energy supply, what is the best course of long-term U.S. energy policy.

Table 1. World level summary of petroleum estimates for undiscovered conventional petroleum and reserve growth for oil, gas, and natural gas liquids (NGL).

[BBOE, billions of barrels of oil equivalent. Six thousand cubic feet of gas equals one barrel of oil equivalent. F95 represents a 95 percent chance of at least the amount tabulated. Other fractiles are defined similarly. Production and reserves normalized to 1/1/96. Shading indicates not applicable]

	Oil				Gas					NGL			
	Billion Barrels				Trillion Cubic Feet				BBOE	Billion Barrels			
	F95	F50	F5	Mean	F95	F50	F5	Mean	Mean	F95	F50	F5	Mean
World (excluding United States)													
Undiscovered conventional	334	607	1,107	649	2,299	4,333	8,174	4,669	778	95	189	378	207
Reserve growth (conventional)	192	612	1,031	612	1,049	3,305	5,543	3,305	551	13	42	71	42
Remaining reserves*				859				4,621	770				68
Cumulative production*				539				898	150				7
Total				2,659				13,493	2,249				324
United States													
Undiscovered conventional**	66		104	83	393		698	527	88	Combined with oil			
Reserve growth (conventional)**				76				355	59	Combined with oil			
Remaining reserves				32				172	29	Combined with oil			
Cumulative production				171				854	142	Combined with oil			
Total				362				1,908	318				
World Total (including United States)				3,021				15,401	2,567				

*World reserve and cumulative production data reflect only those parts of the world actually assessed and are from Petroconsultants (1996) and NRG Associates (1995).

**U.S. data from Gautier, D.L., Dolton, G.L., Takahashi, K.I., and Varnes, K.L., eds, 1996, 1995 National assessment of United States oil and gas resources--Results, methodology, and supporting data: U.S. Geological Survey Digital Data Series DDS-30, release 2, one CD-ROM, and from Minerals Management Service, 1996, An assessment of the undiscovered hydrocarbon potential of the Nation's outer continental shelf: Minerals Management Service OCS Report, MMS 96-0034, 40 pages.

Source: USGS, 2000, World Petroleum Assessment 2000, Description and Results.

U.S. ENERGY POLICY OPTIONS

When estimating a country's remaining energy resources it is generally assumed that the least expensive and most abundant oil and gas resources are found and consumed first. And, as a country consumes more and more domestic energy, progressively more expensive oil resources are found and consumed. But, there is another option to consuming all domestically produced energy—foreign oil imports can be substituted for domestic production.

In fact, most countries' oil consumers seek to find the least costly sources of oil, regardless of whether they are derived from domestic or foreign sources. If imported oil is cheaper and more readily available to consumers, foreign oil will be preferentially consumed.

A. Energy Security

Much has been written about the security of U.S. supplies of oil—whether it is from domestic production or from imports. A particularly strong argument about energy security is that security of energy supplies increases as diversity of sources increases. This is the same concept that investment advisors counsel their clients'security comes from not placing all of your eggs in one basket. Thus, a mix of domestic production and imports from a multitude of foreign sources actually represents most countries' best source of energy security. Currently, the U.S. imports as much oil from non–OPEC as OPEC sources. The four largest sources of U.S. oil imports include not only Saudi Arabia, but also Canada, Mexico, and Venezuela. In many ways this reliance on disparate geographical sources of oil imports decreases U.S. dependence on domestic sources of oil and thus increases our energy security.

This presumption seems to fly in the face of the common implicit assumption that domestic oil production is preferred to imports. But, there are at least two disadvantages to exclusively consuming domestic oil; (1) a barrel of domestic oil consumed now means that there is one less barrel of oil in the ground for future consumption'thereby decreasing future policy options and increasing the effect that any potential future foreign oil import interruption may have on this country.

And, (2) U.S. domestic oil production tends to be more expensive to produce than imported oil'the costs of lifting, transported, and marketing U.S. domestic oil tend to exceed similar imported oil costs. The reason for this is that U.S. oil is produced from the world's most mature energy province. Most of the cheapest and most abundant oil has already been produced in the U.S. Meanwhile there are many foreign sources of oil—including non–OPEC, OPEC, Western and Eastern Hemisphere sources that are not as intensively explored and therefore the costs of bringing this oil to U.S. markets is much lower than domestic production.

Yet another potential disadvantage of using only U.S.-produced oil is that it comes from a huge number of sites throughout the U.S. Domestic oil and gas is shipped by pipeline, tanker-truck, and other sources. The terrorists of 9/11 showed that America's huge geographical breadth is not immune from attackers. The vast pipeline network, domestic oil refineries and petrochemical complexes represent a tempting target for future terrorists. One might argue that these large spider-webs of oil refining and shipping might at least as vulnerable as the large supertankers that ship U.S. oil imports from many different points of the globe.

B. U.S. Domestic Oil and Gas Endowment

Virtually all studies have shown that, if every acre of U.S. land was opened up to drilling—including all parks, wilderness areas, and every offshore acre out as far as the 200-mile limit, the U.S. can never realistically expect to be able to produce all of its own energy. Not now, and not in the future. And, even if this country were able to produce every barrel of oil that it consumes, it may not be a desirable U.S. policy to maximize domestic energy production.

C. U.S. Supply–Side and Demand–Side Energy Policy Options

Nature has endowed this country with a finite amount of petroleum that cannot be changed by any government's policies. It can be argued that supply-side actions, such as subsidizing the production of ever-decreasing amounts of domestic oil at progressively greater costs is ultimately wasteful and counter-productive if one is pursuing energy security.

One might say that this country could learn from the fundamental changes in international energy markets that started in the 1970s. Instead of encouraging more production of more expensive domestic oil and gas, this country could be concentrating on managing more productive energy policies. That is, this country could look not at supply-side policies, but instead could try to manage the demand-side of the energy equation.

That is not to say that no supply-side actions might be appropriate'subject to the other potential uses of the land. There are strong arguments that this nation could support research into more efficient extraction of domestic energy resources. Of special interest are those policies that support research into wringing out more barrels of oil and gas from existing oil- and gas-fields. Currently producing fields typically do not produce as much as one-half of the identified oil-in-place. Productive energy policies could include advances in better visualizing the underground reservoirs and increasing the proportion of oil-in-place that is actually produced. These enhanced oil recovery (EOR) technologies tend to be expensive, but can be applied to known

fields that already have the entire energy production infrastructures in place. In addition, existing energy production regions, such as the Gulf Coast onshore and offshore also tend to already have a well-trained, experienced workforce in a region that is currently set up to produce oil and gas efficiently. Another significant benefit of these EOR policies would be that fewer or no new pristine and un-roaded areas need to be disturbed for energy production.

Drawing on this nation's recent history, there are some proven and very effective demand-side energy strategies. These effective policies that have been used before concentrated on (1) using oil and gas more efficiently, and (2) researching energy alternatives to conventional oil and gas. Collectively, these two broad strategies have had the effect of decreasing the amount of oil and gas needed by the country and thereby have increased the energy security of this nation. Also, recent U.S. history has shown that pursuing greater energy-use efficiencies and alternative energy sources does not mean that consumers must degrade their standard of living and make do with less. Instead, these two strategies can lead to an ever-increasing standard of living at a lower overall cost.

For example, as we have seen in the last 20 years, Detroit has not raised the fuel efficiency of automobiles and light trucks. The average miles-per-gallon of these vehicles has actually decreased since the mid–1980s. But, in the 1970s and early 1980s Congress passed a binding set of standards that mandated higher fuel efficiency from these vehicles. Average fuel efficiency increased by 50 percent and more from earlier levels. The effect of this legislation was that consumers in the late 1980s drove cars and light trucks that were (1) more fuel efficient, (2) produced much less air pollution, (3) employed many more safety standards, and (4) actually produced greater power than vehicles of the 1970s. Instead of degrading the standard of living in this country the Corporate Average Fuel Efficiency (CAFE) standards actually led to improvements in every aspect of driving—including significant reductions in pollution and greenhouse gases. Both consumers and the automotive industry thrived.

And, the impact of CAFE standards was not just isolated to a small portion of the energy sector. About two-thirds of all oil used in this country is used in the transportation sector. Congressional actions to improve fuel efficiency had a very significant impact on increasing this nation's overall energy security, resulting in a large reduction in U.S. oil demand.

However, since the mid–1980s the U.S. has not moved to raise CAFE standards. In fact the standards have actually declined slightly since that time. Instead of building on past triumphs, the U.S. has been content to rest on its laurels. In the absence of a mandate from Congress, Detroit has not moved on its own to raise the mileage of cars and light trucks. As a result, the country's appetite for oil has been growing faster than it would have with more efficient cars and trucks. Another impact of this policy is that the production of airborne pollutants from cars and trucks has also not been controlled.

The Bush Administration has proposed that energy incentives should be differentially applied to the supply-side of the energy sector. These incentives would largely have the effect of producing an ever-greater proportion of this nation's finite supply of oil. At the same time, the Administration is not concentrating on effectively using the demand-side incentives to use our oil and gas more efficiently. Pursuing this course of action will likely lead the U.S. to use up our domestic oil and gas at increasing rates, and allow less-efficient energy technologies to produce more pollution.

The most-effective and least-intrusive energy policies that this country could pursue might be three-fold. (1) Get the most energy out of currently producing oil and gas fields using enhanced oil recovery (EOR). (2) Concentrate on making this nation's stock of energy-using technologies more efficient, so that every barrel of oil and every Mcf of gas could produce greater benefits to the users. And (3) develop new technologies that would give this country alternatives to conventional oil and gas—and substitute renewable energy sources such as solar, wind power, and biomass for conventional energy sources.

REFERENCES

U.S. Geological Survey, 2000, World Petroleum Assessment 2000, Description and Results.

[NOTE: The report entitled "Examination and Critique of ARI Report: Undiscovered Natural Gas and Petroleum Resources Beneath Inventoried Roadless and Special Designated Areas on Forest Service Lands Analysis and Results, with Additional Discussion of U.S. Geological Survey and National Petroleum Council Reports" has been retained in the Committee's official files.]

A Brief Examination of the Adequacy of Future U.S. Natural Gas Infrastructure and Resources

AND

The Role of Public Lands in U.S. Natural Gas Production

A Report to The Wilderness Society

By Lookout Mountain Analysis

W. Thomas Goerold, Ph.D.

<TGOEROLD@LOOKOUTMTN.COM>

June 18, 2001

I. INTRODUCTION AND LAYOUT

This paper gives a concise description of some of the known and undiscovered natural gas resources that may underlie this nation's public lands. Included in this paper is an outline of current producing areas and a discussion of the locations of likely future producing areas—with distinctions drawn between Federal, non–Federal, onshore and offshore lands. Also found in this study is a summary of some of the constituents of U.S. natural gas infrastructure and recent trends in the sector. This paper additionally gives descriptions of the magnitude of existing, planned, and permitted natural gas pipeline projects. This information informs the reader about imminent additions to near-term future gas capacity and increased deliverability. Finally, this study briefly summarizes projected future U.S. natural gas supply, prices, and conclusions.

Section II describes locations of currently producing areas. Section III looks at a statewide summary of the locations of current major gas reserves. Section IV examines the likely areas where future gas production will occur, with a brief discussion of contributions from Federal, non–Federal, onshore, and offshore lands. Section V briefly explains the components of the nation's natural gas supply network and summarizes recent trends in gas prices and consumption. Section VI lists recent and planned near-term future natural gas infrastructure improvements, with an analysis of their planned impacts on increasing the total quantity and efficiency of national natural gas supplies. Section VII summarizes the Department of Energy's projections on future price and availability of natural gas in the Untied States. Finally, Section VIII gives a summary and major conclusions of this report and Section IX discloses selected references.

II. CURRENT GAS PRODUCTION FROM ONSHORE FEDERAL LANDS

Total onshore- and offshore-marketed U.S. gas production in 2000 was about 20.1 trillion cubic feet (Tcf) (DOE/EIA, 2001a). Gas production from all onshore Federal gas leases amounted to approximately 2.0 Tcf, or about 10 percent of national gas production. New Mexico public lands produced about 5.5 percent of all U.S. gas production in 2000.

Approximately 53 percent of all onshore Federal gas royalties can be traced to New Mexico producing wells, 33 percent from Wyoming, 4 percent from Colorado, 4 percent from Utah, 2 percent Texas, 1 percent Oklahoma, and about 0.1 percent Louisiana. Sixteen other states accounted for the other 3.6 percent of Federal gas royalties from onshore production. Using an average annual citygate price for all U.S. natural gas production of $4.70 per Mcf, total marketed value in 2000 was about $94 billion. Total receipts from these onshore Federal gas royalties gas were about $611 million in 2000—approximately 0.7 percent of the value of total U.S. natural gas output.

III. CURRENT U.S. NATURAL GAS RESERVES

Detailed data are not readily available to show the Federal/non Federal breakdown of current natural gas reserves. An examination of gas reserves on a statewide basis shows that the seven largest concentrations of reserves, comprising 75 percent of total U.S. gas include onshore Texas (24 percent), followed by New Mexico (9 percent), Wyoming (9 percent), Oklahoma (7 percent), Alaska (6 percent), and Louisiana (6 percent). Offshore Federal areas in the Gulf of Mexico collectively contain about 15 percent of current U.S. natural gas reserves.

IV. UNDISCOVERED ECONOMICALLY RECOVERABLE GAS RESERVES

All Onshore Lands and State Offshore Lands

USGS data show that there is about 196.3 Tcf of natural gas yet to be discovered in onshore and state offshore (up to three miles out to sea) areas at a gas price of about $3.90 per Mcf (2001 dollars) (USGS, 1995). About 70.5 Tcf (36 percent) of this gas is expected to come from the onshore and state offshore areas bordering Texas and Louisiana. Another 29.1 Tcf (15 percent) is expected to be found in the Rocky Mountains and Northern Great Plains regions, about 35.2 Tcf (18 percent) from the Colorado Plateau and Basin and Range provinces, as well as about 13 Tcf (7 percent) from West Texas and Eastern New Mexico, and about 14.2 Tcf from Midcontinent areas (7 percent).

Federal Onshore Lands

According to USGS estimates there is likely about 36.9 Tcf of economically recoverable gas at prices of about $3.90 per Mcf to be found in all onshore Federal lands—about 19 percent of total undiscovered U.S. onshore gas and 12 percent of total economically recoverable undiscovered U.S. gas resources. The region with the largest amount of the gas in Federal onshore lands is the Colorado Plateau and Basin and Range Province (parts of CO and NM, AZ, UT, NV) with about 19.4 Tcf. Also, the Rocky Mountain and Northern Great Plains Province (MT, ND, ID, WY, parts of CO) contains about 14.3 Tcf. The remaining 3.2 Tcf of economically recoverable gas that is expected to be found underneath other Federal onshore lands is scattered throughout the rest of the country (including Alaska).

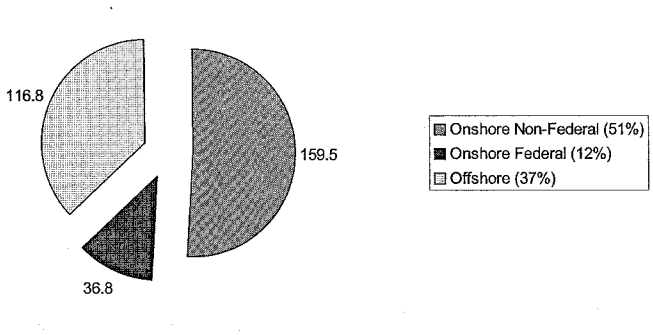
Federal Offshore Lands

The Minerals Management Service (MMS) gives estimates of undiscovered economically recoverable gas from Federal offshore lands of 116.3 Tcf (MMS, 2001). However, the agency uses a gas price of only $2.11 per Mcf. As a result, the MMS estimate of 116.3 Tcf at $2.11 per Mcf almost certainly significantly underestimates the amount of undiscovered natural gas that would be economically recoverable at gas prices of $3.90 per Mcf. Combining the very conservative MMS estimate with USGS estimates yields a total estimate of economically recoverable gas in all onshore and offshore lands of at least 313.1 Tcf with gas prices of about $3.90 per Mcf.

Gas Resource Distribution by Land Categories

Figure 1 graphically shows the relative contributions of undiscovered economically recoverable natural gas reserves from onshore Federal and non–Federal lands, and from offshore Federal lands. The relative endowment of economically recoverable natural gas from offshore lands is likely to be very underestimated relative to onshore estimates. Offshore resource estimates from MMS assume a gas price of just $2.11 per Mcf gas. In contrast, the USGS onshore resource estimates assume a gas price of $3.90 per Mcf gas.

Figure 1 – Economically Recoverable Natural Gas at $3.90 per Mcf (onshore) and $2.11 per Mcf (offshore), (Tcf)



Sources: USGS, 1995, OF 95-75-N, and MMS, 2001, News Release, January 17, 2001.

Despite the different gas price estimates, Figure 1 gives some indication of the relative importance of the different types of land for natural gas resource estimates.

Figure 1 shows that the maximum contribution of economically recoverable natural gas from onshore Federal lands is about 12 percent of the estimated total undiscovered gas resource of 313 Tcf. Non-federal onshore lands likely hold at most 51 percent, and offshore lands hold at least 37 percent of total undiscovered economically recoverable natural gas.

Likely locations of future reserves of as-yet-unidentified bodies of natural gas have been detailed by the USGS. About 33.7 Tcf of undiscovered economically gas (at $3.90 per Mcf) is likely to be found underneath western Federal onshore lands. This quantity represents about a maximum of 11 percent of the nation's total future gas reserves. Most of the expected undiscovered economically recoverable gas is expected to be found within non–Federal onshore lands (<51 percent), and from Federal offshore lands (>37 percent).

V. NATURAL GAS INFRASTRUCTURE AND TRENDS

Infrastructure

Several entities collectively comprise the U.S. natural gas system. Producers are individuals and companies that find and produce natural gas from the ground. Prices at the wellhead (point at which the gas emerges from the ground) are unregulated. Producers have freedom to negotiate any mutually agreeable prices and terms with downstream parties.

Gathering lines from multiple wellheads transmit gas to processing plants where noxious gases and natural gas liquids are removed prior to the gas entering transmission pipelines. Most gathering pipelines fall under state jurisdiction.

Transmission pipelines convey processed gas to specific delivery points that may include storage facilities, other transmission pipelines, or a "citygate" (entry point of gas from transmission pipeline to a Local Distribution Company [LDC]). Pipelines that span more than one state have their rates and terms and conditions of service regulated by the Federal Energy Regulatory Commission (FERC). Pipelines confined to one state are typically regulated by that state's Public Utility Commission (PUC).

Natural gas is not consumed at a uniform rate throughout the year. It is used at a much greater rate during winter months, primarily for space heating. In anticipation of the greater drawdown of gas during the winter months, much of the gas produced during other seasons is "parked" in storage facilities. Gas can then be drawn at a greater rate from storage facilities than from initial production and processing areas as it is needed throughout the year.

Local Distribution Companies (LDCs) move the gas from citygates to intermediate and final users of natural gas. Much of the end-user cost of natural gas can be traced to the capital and operating costs of building and maintaining the spider-web of small pipeline networks that convey the gas to the multitude of end users.

Marketers are companies that perform "packaging" functions for natural gas consumers. These firms may contract with a variety of producers, pipelines, LDCs, and other companies to sell a discrete package of natural gas supply, storage, and delivery under various prices and conditions.

Recent Trends

CONSUMPTION

Consumption of natural gas reached a record level of 22.8 trillion cubic feet (Tcf) in 2000—a growth of about five percent over 1999 (DOE/EIA, 2001b). Most of the annual variation in natural gas consumption can be attributed to winter temperatures. Colder winters produce a greater demand for gas.

But, trends in natural gas consumption are more complex than weather patterns. In 2000 about 40 percent of gas consumption came from the industrial sector. Gas is primarily used in this sector for cogeneration (combined power and heating), and as a feedstock to produce other hydrocarbon-based goods. Seasonal demand in this sector is the least temperature-sensitive. Although some industrial users of natural gas can switch between fuels (a typical gas substitute is fuel oil) with energy price changes, most industrial users of natural gas do not have that capability.

The residential and commercial sectors collectively consumed about 40 percent of gas in 2000. Increases in natural gas demand in the residential sector can be linked to increases in the average size of homes and the fact that in 1999 more than 70 percent of new homes use natural gas for heat, compared with 47 percent in 1986. Commercial use of natural gas has increased even faster than residential use. Both of these sectors' natural gas consumption is quite temperature sensitive. Peaks in gas consumption almost invariably occur during January and February for these users.

The other 20 percent of natural gas consumption in 2000 can be traced to the electrical generation sector. Natural gas is used as a fuel for at least two types of electrical generators (1) combustion turbines and (2) combined-cycle plants. Combustion turbines have the advantage of being relatively cheap and quick to build, have high efficiencies, and can be turned on and off quickly to satisfy short-term peaks in demand for electricity. But, combustion turbines are not usually the only source of electricity at generating stations because they are relatively expensive to operate. Combined-cycle plants use gas-fueled boilers and apparatus to combine power-generation and heating functions. Seasonal peaks in natural gas demand occur during the summer months in the electrical generation sector (air-conditioning demand), with smaller peaks during the winter months (space-heating demand). Thus, to some extent, seasonal peaks in the electrical generation sector are not coincident with industrial, commercial, and residential sectors.

PRICES

Prices of natural gas reached unusually high seasonal peaks during the winter months of 2000–2001, particularly natural gas prices in the Western U.S. and California. Citygate prices during the winter ranged from about $6.60 in Chicago, to more than $15.00 in Southern California. In the third quarter of 2000, prior to the winter of 2000–2001, natural gas prices varied from about $4.50 in Chicago to $5.30 in Southern California.

While it is common for natural gas prices to rise during the winter months, the amount of seasonal and regional variation seen last winter is unusual. Most experts attribute the large price increases to several factors; (1) a long-term trend of relatively low natural gas prices during most of the 1990s that limited producers' cashflow and led to low levels of natural gas exploration and production, resulting in decreases in the natural gas supply; (2) increases in gas consumption that were encouraged by the relatively low gas prices (see the preceding sections); (3) unusually cold winter months over much of the U.S. during January and February 2001; (4) uncharacteristically low levels of rainfall in the western U.S. that led to smaller-than-normal amounts of hydropower available for electrical generation in the Western U.S.; and (5) an August 2000 rupture in an El Paso natural gas pipeline connecting natural gas from producing centers in Colorado, Texas, Wyoming, and New Mexico to consuming centers in California, Arizona, and New Mexico.

NATURAL GAS SUPPLY

In a free market economy prices represent an investment signal. Increases in natural gas prices that commenced in about 1999 were interpreted by natural gas producers as a call for increasing natural gas supplies. With the increased cashflow available from higher natural gas sales revenues, producers stepped up their natural gas drilling campaigns. The Oil and Gas Journal reported that 154 independent U.S. producers increased capital spending by 48 percent from 1999 to 2000 and planned a further increase of 35 percent in 2001 (as reported in DOE/EIA, 2001b).

The frenzied pace of natural gas exploration and production in this country shows no signs of abating soon. As a matter of fact, as reported by Natural Gas Week, U.S. contractors and service companies are "flinging themselves into a headlong rush for rigs as the boom is beginning to take on fabled proportions." First quarter 2001 profits reported by one of the largest natural gas service companies, Baker and Hughes, rose by 600 percent compared with a year earlier (as reported in DOE/EIA, 2001b).

In 2000 there were about 720 rotary rigs working, an increase of 45 percent from 1999. There are now few or no inactive drilling rigs now available in this country. Clearly, the natural gas sector is now in the midst of a boom fueled by the relatively high natural gas prices. There is not apparent shortage of available targets in the U.S. for producers that are completely utilizing available natural gas drilling rigs.

Only now are the results of the increased exploration and production actions commencing in late 1999t beginning to be seen in the marketplace. The lag between drilling and the addition of natural gas reserves is usually about 6 to 18 months. After hitting a low of 18.6 Tcf of production in 1999, natural gas production increased by 0.7 Tcf in 2000, with significant additional production increases likely as time goes on.

In tandem with recent increasing domestic activity, imports and exports of natural gas from Canada and Mexico, and imports of Liquified Natural Gas (LNG) from abroad have increased as well. About 94 percent of all gas imports into the United States came from Canada in 2000. Our northern neighbor has very extensive deposits of the fuel. Canada continues to link its large natural gas resources with major U.S. consuming centers. Imports of Canadian gas showed annual increases of 5 per-

cent in 2000, 10 percent in 1999, 5 percent in 1998, 1 percent in 1997, and 2 percent in 1996. Most of the import increases were due to increased pipeline capacity within and between the two countries.

VI. NATURAL GAS INFRASTRUCTURE IMPROVEMENTS

The large price differential between citygate prices of natural gas of Southern California and Chicago in early 2001 discussed above ($15.00 vs. $6.60), shows the importance of natural gas infrastructure in determining end-user natural gas prices. The natural gas infrastructure was not able to deliver enough gas from the wellhead to the end users in Southern California. The result was a more than $8.00 price differential between citygate prices. Improvements in the natural gas infrastructure will help ensure that gas delivery flexibility will exist in the future to help eliminate very large regional price differentials. The problem was not an inadequacy of natural gas at the wellhead, but a deficiency in the natural gas delivery mechanism to the end user.

More than 165 U.S. inter- and intra-state pipelines contain about 278,000 miles of transmission lines along with many related structures and facilities. About 1,300 LDCs deliver gas to intermediate and end users through another 700,000 miles of pipelines.

Most often, the sources of natural gas are not located near the population centers containing the majority of the users of natural gas. As new sources of gas are found and developed they must be linked with new and existing pipelines to deliver the gas to the ultimate users. The natural gas infrastructure must also be linked with extensive storage facilities in order to maximize the efficiency in delivering this fuel whose demand has so much seasonal variation. Pipeline utilization levels in some parts of the West (particularly California) have recently been consistently above 95 percent (DOE/EIA, 2001b). Such high utilization rates leave little time for essential maintenance and capital improvements.

Since 1999, more than 60 natural gas pipeline projects have been completed and placed in service. These projects have increased capacity by more than 12.3 billion cubic feet per day (bcfd)—an increase of 15 percent over the 1998 level (DOE/EIA, 2001b). Most recent pipeline capacity additions have focused on bringing more Canadian gas into the U.S. Northeast and Midwest.

Also, increases in coalbed methane production from the Rocky Mountains in Wyoming and Montana have created the need for more pipeline capacity from that region to end users. Only recently have proposal been made to move the large increases in gas seen in the Rocky Mountain region to areas where it is can be used.

In the last five years there have been very extensive pipeline improvements made in order to transport the huge amounts of gas found in the Gulf of Mexico to consuming regions. From 1997 to 1998, 14 gas pipeline projects added about 6.4 billion cubic feet per day of capacity to the region.

The Department of Energy reports that there are 88 announced pipeline projects proposed over the next several years. These proposals would add an additional 20.8 billion cubic feet per day of capacity. The Midwest would add the most capacity (5.1 bcfd), followed by the Northeast (4.8 bcfd), Southeast (4.2 bcfd), Far West (2.6 bcfd), Southwest (2.0 bcfd), and Centeral (2.0 bcfd). These projects would collectively increase the nation's gas transportation capacity by about 22 percent.

LDCs have also been expanding at a rapid rate. American Gas Association estimates show that construction projects by distribution companies increased by 16 percent in 1998 and 1999 compared with 1996 and 1997 (as reported in DOE/EIA, 2001b).

VII. NATURAL GAS PRICE AND SUPPLY PROJECTIONS

The energy sector is notorious for going through periods of boom-and-bust, especially in the last three decades. One only has to look backwards to 1998 to early 1999 to see that the natural gas industry in a bust cycle. The booms and busts in oil and gas are not necessarily coincident.

The Department of Energy (DOE) projects that the natural gas sector will continue to in a "boom period" during the near term. The next few years will likely exhibit relatively high natural gas prices and concomitant high levels of domestic exploration and development, as well as elevated levels of capital spending on infrastructure improvements. From 2000–2002 natural gas consumption is projected by DOE to grow at an annual level of 3.6 percent, compared with the 1994–1999 annual level of 0.9 percent (DOE/EIA, 2001c).

But, the same relatively high prices that encourage increased activity on the natural gas supply side will also discourage new and existing investments in natural-gas-using equipment. Also, high gas prices will especially encourage the industrial

sector to invest in fuel-switching capabilities that would allow them to decrease their natural gas demand during periods of high prices.

DOE estimates that natural gas resources are expected to be adequate to meet future gas demand through 2020 (the last year of the forecast). In concert with this conclusion, long-term prices of natural gas in this country are expected to return to a lower price path in 2005 and then gradually increase to about $3.05 per Mcf in 2020. Advances in drilling and production efficiency applied to domestic gas resources, greater availability of imports from Canada and Mexico, and LNG imports from abroad are expected to adequately satisfy U.S. demand for natural gas to at least 2020.

The National Petroleum Council (NPC) agrees with DOE in its assessment of the size and availability of natural gas resources, saying that "the estimated natural gas resource base is adequate to this increasing demand for many decades, and technological advances continue to make more of those [natural gas] resources technically and economically available (NPC, 1999)."

VIII. CONCLUSIONS

Gas production from all onshore Federal gas leases in 2000 amounted to approximately 2.0 Tcf, or about 10 percent of national gas production. New Mexico public lands produced about 5.5 percent of total U.S. gas output and 53 percent of all onshore Federal gas royalties. Wyoming, Colorado, Utah, Texas, and Oklahoma Federal lands also contributed Federal royalties from gas production Total receipts from these onshore Federal gas royalties gas represented about 0.7 percent of the market value of total U.S. natural gas output in 2000.

Future contributions from onshore Federal lands to domestic natural gas production is likely to be limited to about 37 Tcf—about 12 percent of the estimate of total national economically recoverable undiscovered gas resources of 313 Tcf. Non-federal onshore lands likely hold at most 51 percent, and offshore lands hold at least 37 percent of likely future gas production.

Natural gas in the ground is usually found by producers, fed into gathering lines that move the gas to processing facilities, and then route it into gas pipelines. These pipelines then typically convey the gas to (1) storage facilities, or (2) citygates where it is further distributed by Local Distribution Companies (LDCs), or (3) other pipeline nodes.

Consumption of natural gas reached a record level of 22.8 trillion cubic feet (Tcf) in 2000—a growth of about five percent over 1999. Prices of natural gas also reached unusually high seasonal peaks during the winter months of 2000–2001.

While it is common for natural gas prices to rise during the winter months, the amount of seasonal and regional variation seen last winter is unusual. Most experts attribute the large price increases to several factors; (1) a long-term trend of relatively low natural gas prices during most of the 1990s that limited producers' cashflow and led to low levels of natural gas exploration and production, resulting in decreases in the natural gas supply; (2) increases in gas consumption that were encouraged by the relatively low gas prices; (3) unusually cold winter months over much of the U.S. during January and February 2001; (4) uncharacteristically low levels of rainfall in the western U.S. that led to smaller-than-normal amounts of hydropower available for electrical generation in the Western U.S.; and (5) an August 2000 rupture in an El Paso natural gas pipeline connecting natural gas from producing centers in Colorado, Texas, Wyoming, and New Mexico to consuming centers in California, Arizona, and New Mexico.

With the increased cashflow available from higher natural gas sales revenues, producers stepped up their natural gas drilling campaigns. The Oil and Gas Journal reported that 154 independent U.S. producers increased capital spending by 48 percent from 1999 to 2000 and planned a further increase of 35 percent in 2001. Clearly, the natural gas sector is now in the midst of a boom fueled by the relatively high natural gas prices. There is no apparent shortage of available prospective natural gas drilling targets, as evidenced by the almost complete utilization of available drilling rigs.

After hitting a low of 18.6 Tcf of production in 1999, natural gas production increased by 0.7 Tcf in 2000, with significant additional production increases likely as time goes on. In tandem with recent increasing domestic activity, imports and exports of natural gas from Canada and Mexico, and imports of Liquified Natural Gas (LNG) from abroad have increased as well.

The large price differential between citygate prices of natural gas of Southern California and Chicago in early 2001 discussed above ($15.00 vs. $6.60), shows the importance of natural gas infrastructure in determining end-user natural gas prices. The natural gas infrastructure was not able to deliver enough gas from the wellhead

to the end users in Southern California. The result was a more than $8.00 price differential between citygate prices. Improvements in the natural gas infrastructure will help ensure that gas delivery flexibility will exist in the future to help eliminate very large regional price differentials. The problem was not an inadequacy of natural gas at the wellhead, but a deficiency in the natural gas delivery mechanism to the end user.

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[Responses to questions submitted for the record by Mr. Goerold follow:]

MAY 8, 2002

Barbara Cubin, Chairman
Committee on Resources
Subcommittee on Energy and Mineral Resources
1625 Longworth HOB
Washington, DC 20515

Dear Ms Cubin:

I was a scheduled witness for the April 18, 2002 Oversight Hearing on Oil and Gas Resource Assessment Methodology. Although I did submit written testimony for the hearing record, I was unable to attend the hearing and give oral testimony, because of illness.

This letter responds to four questions submitted to me after the April 18, 2002 Hearing:

Q1. Regarding your analysis entitled "Examination and Critique of ARI Report: Undiscovered Natural Gas and Petroleum Resources Beneath Inventoried Roadless

and Special Designated Areas on Forest Service Lands "," did the Hewlett Foundation or the Energy Foundation pay for any of this study?

A1. Absolutely not.

Q2. Please cite the studies that show "that if every acre of U.S. land was opened up to drilling, including all parks, wilderness areas, and every offshore acre out as far as the 200-mile limit, the U.S. can never realistically expect to be able to produce all of its own energy. Not now and not in the future.

A2. There are many contributory studies that give estimates of the amounts of discovered and yet-to-be-discovered oil, gas, and other energy sources in the United States. When one matches up the estimates of future domestic energy production with estimates of future U.S. energy consumption, it becomes readily apparent that the U.S. does not and will not have the capability of producing all of its energy needs as measured by any defensible mineral economics estimates.

One document that I can use to support the questioned statement in my recent testimony is from the U.S. Geological Survey. It is titled "Economics and the 1995 National Assessment of U.S. Oil and Gas Resources", U.S.G.S. Open–File Report 95–75–M, by Emil D. Attanasi.

Mr. Attanasi projects that a maximum of 69 billion barrels of oil (BBO) could be available for production from 1994 to 2015 (USGS OFR 95–75–M). The 69 BBO is derived from summing discovered and undiscovered conventional and unconventional oil resources that would be available at real oil prices up to $30 per barrel (in 1994 dollars).

DOE's Energy Information Administration (EIA) shows historical and projected U.S. oil consumption from 1994 to 2000 and projected consumption from 2000 to 2015 (EIA, website, Table 5.1 Petroleum Overview 1949–2000, and Table 21, International Petroleum Supply and Disposition, 1999 to 2020). Adding together the total petroleum products consumed from 1994 to 2000 (47.59 BBO) and projected consumption for the same commodities from 2001 to 2015 (125.00 BBO), results in a total historical and projected petroleum product consumption of 172.58 BBO for the period 1994-2015. This amounts to 103.58 BBO more than the maximum available amount of 69 BBO, as estimated by Mr. Attanasi.

The above exercise shows that U.S. petroleum product consumption during Mr. Attanasi's study period (1994–2015) would amount to about 250 percent of the maximum possible domestic petroleum supply. And, this exercise also assumes that all U.S. oil would be completely consumed by the year 2015. This is not a likely scenario.

It is possible that the inflation-adjusted oil price could exceed $30 per barrel (in 1994 dollars, I believe). It is also possible that Mr. Attanasi has under-estimated the amounts of economically producible oil that is known and yet-to-be-discovered in the U.S. However, Mr. Attanasi's estimates would have to be more than 250 percent in error in order to come to the conclusion that the U.S. has enough domestic oil to supply its own needs from 1994 to 2015.

A second piece of evidence to support my assertion that the U.S. cannot be self-sufficient in oil production can be inferred by looking at the attached graph that I produced (Figure 1). This graph compares EIA estimates of future petroleum consumption, domestic production, and the potential impact of a 3.2 billion barrel find of oil from the Arctic National Wildlife Refuge (ANWR), Alaska.

Figure 1 shows the huge gap between domestic oil production and projected consumption. Short of a combination unforeseen and miraculous events, I believe that no reasonable energy analyst will predict that any policy actions by the U.S. could result in this country producing all of its oil needs.

Q3. I have enclosed a recent article in Newsday that describes ongoing research at Woods Hole Oceanographic Institution indicating that some U.S. oil and gas reservoirs are being recharged, perhaps from an as yet unknown source. In some cases known structures are refilling relatively rapidly. This is evident in the Gulf of Mexico and may very well be occurring elsewhere. Would you comment on the implications this ongoing research could have [on] the long term outlook for U.S. oil and gas supply, both generally and particularly with regard to the statement above?

A3. The U.S. has been producing oil since the mid–1850s. In that time this country has become the most thoroughly-explored oil province on earth. I believe that the observations referred to in the above article are apparently very preliminary and have not yet been exposed to scientific scrutiny over time. Because I am not familiar with these specific circumstances, my statements are only speculative in nature.

Having qualified my remarks, I would say that, if there were shown to be a mechanism that is recharging depleted and depleting oil fields over time, that the rate of recharge would most likely be measured in geologic time, not in years. Otherwise

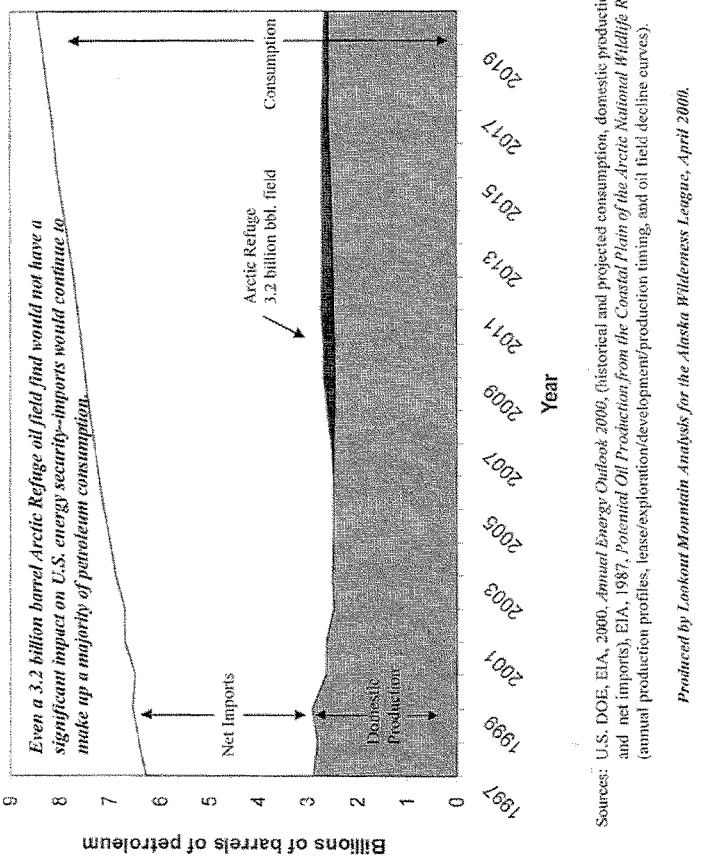
the recharge phenomenon would have already been observed in the approximately 150 years worth of historical U.S. oil production.

But, if science does show that there is some "rapid-recharge" mechanism working in this country, it would strengthen some of the most prominent statements that I made in my written testimony to this Committee.

The cheapest and most environmentally benign sources of future oil and gas in the U.S. are likely to be found within the boundaries of already discovered oil fields, not in the few remaining unexplored regions. Because most mineral economists assume that we have already found the majority of oil and gas that existed within U.S. boundaries, the largest sources of any "rapid-recharge oil" would also likely be found in already identified oil fields.

Additionally, the U.S. can reap an added bonus from more intensive exploitation of known oil fields. On average, even in "depleted" oil fields there is likely more oil still remaining in known oil fields than has ever been produced from them. By concentrating on recovering the 50 percent-or-more of remaining oil in known fields, this country can leverage the huge investment already made in oil field infrastructure, pipelines, refineries, companies, and people that exist in known oil fields and regions.

Figure 1



Sources: U.S. DOE, EIA, 2000, *Annual Energy Outlook 2000*, (historical and projected consumption, domestic production, and net imports), EIA, 1987, *Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge*, (annual production profiles, lease/exploration/development/production timing, and oil field decline curves).

Produced by Lookout Mountain Analysis for the Alaska Wilderness League, April 2000.

Ms. CUBIN. So with that, we would like to begin questioning members of this panel, and thank them very much for their well thought-out and very important testimony.

I think I will start with Mr. Morton. And honestly, that is for no particular reason. It was just on top. Did the $172,000 grant from the Hewlett Foundation to The Wilderness Society pay for your study entitled, "The Department of Energy's Federal Lands Analysis Natural Gas Assessment: A Case of Expediency Over Science?"

Mr. MORTON. No.

Ms. CUBIN. Do you know where that grant did come from?

Mr. MORTON. I believe that the grant you are talking about was a grant to hire experts to review some of the environmental impact statements, etcetera, that are currently coming out. Those were experts in academia and other places that were not with The Wilderness Society.

Ms. CUBIN. Right.

Mr. MORTON. So that grant came probably—I don't know—six, 7 months after I did the critique in July. And so that wasn't part of that. We didn't get any money from Hewlett. I would have liked to have had some money; but we didn't get any money to complete that. That was all on our own dime.

Ms. CUBIN. But it was peer-reviewed?

Mr. MORTON. What was peer-reviewed? I'm sorry?

Ms. CUBIN. But was it peer-reviewed?

Mr. MORTON. My critique?

Ms. CUBIN. Correct.

Mr. MORTON. I got advice from other people in the field, including Dr. Tom Goerold, who is not here. But it wasn't through a formal peer-review process.

Ms. CUBIN. OK. Mr. Morton, you have criticized the USGS several oil and gas assessments as being overly optimistic. These assessments' methods have been around since about the late '50's. Can you identify any regional oil and gas assessment that time has proven to be overly optimistic?

Mr. MORTON. I think you are mischaracterizing my criticism. My point with the USGS, for example, was that a lot of the non-market costs that go along with oil and gas extraction were not included. They do simply a financial analysis, which is just cost in dollars and a cash-flow, looking at bringing the gas to the wellhead.

What I was looking at are some of the non-market costs—mitigation, restoration of damages, etcetera—that aren't included in that economic calculus. So I'm not that critical of the USGS. I am just making a note that these are very difficult to quantify values and costs, but they need to be considered in public land management.

With the NPC report and some of the other ones, I was critical of the lack of adequate consideration of economic constraints. And I think in my testimony, when you are looking at the opportunity cost of something you need to look at the net benefits. And that's where the economics kind of plays in.

Ms. CUBIN. I lost my notes here. I will come across them soon. You talked about that all of the land had to be used in the resource management areas. How do you propose to mitigate or compensate the surface holder when land is to be developed, or is approved to be developed?

Or I guess, what mitigation do you think there should be for the surface holder?

Mr. MORTON. I think the surface owner needs to get some consent agreement on the treatment of their property before they allow drilling to occur. I mean, we have this split estate problem, where a lot of the land owners have not been notified about the oil and gas companies coming. And I have heard horror stories from ranchers in Wyoming about oil companies just coming, and dropping a well, and building poorly designed roads, and impacting their grazing, and building water impoundments that take up a lot of land for them, without really any consideration of their damages to their land.

And so I think you need to have some consent agreement from the private property owner before the drilling occurs, to take care of the damages that occur to their land.

Ms. CUBIN. I do, too. I think that, you know, the noise that is made by one of those compressors being 6 feet away from someone's house can certainly devalue the property owner's investment and, you know, maybe even drive him off his home. So I think those are things that need to be taken care of, and need to be decided. Some people shouldn't receive all the reward while others lose out just because that is where they live. Thank you very much, Mr. Morton.

Now, Mr. Mankin, in your opinion, would the RAND approach work well for regional oil and gas assessments?

Mr. MANKIN. No, Madam Chairman, I don't think it would. What it does is, it applies an additional level, or an additional layer, of uncertainty on top of what is already an uncertain process. And simply adding that increases the bounds of uncertainty, and decreases the mean value.

For example, I don't think there is a person in this room that could identify or properly predict the price of a barrel of oil or a cubic foot of natural gas five to 10 years from now, when some of these properties might eventually be developed.

In addition to that, until you drill that first well, that discovery well, you know very little about the reservoir conditions. You don't know whether you have got a homogeneous reservoir. You don't know whether you have got a segmented reservoir. You don't know how many wells it is going to take to develop the resource. You don't know how much water you may have to contend with in connection with your production. You don't know what the quality or quantity of the resource may be in detail.

And so all of these are factors that cannot be determined in advance. And to try to impose an economic value on a resource before you know anything about those conditions imposes an unreasonable burden to anyone attempting to consider that for potential development.

Finally, every oil company has their own economic set of conditions, and none of them are the same.

Ms. CUBIN. Right.

Mr. MANKIN. Over the 35 years that I have been director of the Oklahoma Geological Survey, I have had an opportunity to visit with an awful lot of particularly smaller companies and independent operators, and have looked at their economic conditions. And I can assure you, they range all over the place.

So their economic assessment would be different from any one organization's assessment. And therefore, I think it imposes an additional burden, an unnecessary burden, on the process. The AAPG believes that the only proper thing to do is to use technical resources for such assessments.

Ms. CUBIN. Mr. Otter, do you have any questions of the panel?

Mr. OTTER. Yes. Thank you very much, Madam Chairman.

And I appreciate the panel's discussion and testimony thus far on this issue. Mr. Morton, I got to read briefly most of your testimony prior to the part that I didn't hear. I want you to know that I have become aware of it, even though I didn't get to be here while you were testifying. And much, I would say, of the testimony that you provided relies heavily on some concepts that have been adopted from the RAND report. Is that right? "Assessing Gas and Oil Reserves in the Intermountain West?"

You quoted extensively—I guess what I am saying in here—some of the opinions that were expressed in the RAND report. For instance, in quoting the RAND report you indicate that, "The oil and gas leasing stipulations that dictate where and how and when exploratory drilling may be conducted in order to protect wildlife and the environment are not in many cases binding constraints on energy production." And you quote that from the RAND report.

So do you consider the RAND report an authentic report, and one that you have digested, and one that has had peer review and everything?

Mr. MORTON. Yes, I do. I was actually one of the peer reviewers on the report, and I have digested that report quite heavily.

Mr. OTTER. I see. And in that RAND report, there certainly is the question—and I don't know if you were here when we had the first panel up—my question, as to how we assess economic viability of these. And do you agree, then, too, with the RAND report as far as that goes?

Mr. MORTON. Yes, I do. I think, if you look at economic theory, you need to look at the net benefits of oil and gas extraction. And I thought your line of questioning of the first panel was right on the money, because you can't just estimate gross amounts. You need to say, "What is it going to cost us to get this to market?" Because that is a comparable comparison to the net cost, or net benefits, that you are giving up.

Mr. OTTER. Right. And you heard the response that I received from the panel. And maybe I an re-asking the same question that the good Chairman asked, but can you point me to a project where these assessments were not made and the result was that the expectation, A, was not filled; B, it was not economically viable; and, C, we ended up holding the bag?

Mr. MORTON. Well, I have heard stories from ranchers in Wyoming, where people came in and dropped in dry wells, and left, and left them with all of the cost of cleaning up.

Mr. OTTER. On public lands?

Mr. MORTON. Well, this was split estates; so Federal and—

Mr. OTTER. But Mr. Morton—and I don't want to banter with you—you heard the assessments that the agency makes. It seems to me that perhaps that private land owner didn't make those same assessments. And I would think that whoever owns the land—And

being an advocate of private property, I certainly wouldn't want the government coming in and making an assessment on my property as to whether I should or should not invite exploration of the subsurface wealth on my property.

And so do you basically, then, agree with what the first panel said relative to their assessments?

Mr. MORTON. I am not sure what I am agreeing to.

Mr. OTTER. OK. All right.

Mr. MORTON. But there are a lot of abandoned wells on public land that have not been reclaimed. All right? Hundreds of them, thousands of them. So there are a lot of cases. In fact, the majority of wells drilled in the U.S. have been dry wells, and a lot of those have been on public land. And a lot of those have left scars on the land which have not been reclaimed and have not been restored.

Mr. OTTER. And when did this happen?

Mr. MORTON. Over the last 50 years.

Mr. OTTER. And of course, that is my point. Wouldn't you agree that there are now, because of what the agency themselves said, safeguards in place that would guard against that happening again? When was the last time a dry well was left and the scar was left on the earth?

Mr. MORTON. I don't have exact information.

Mr. OTTER. OK.

Mr. MORTON. My point would be, even if you have stipulations that are designed to protect the environment, a lot of the times the bonding requirements are not enough to cover the cost of reclamation.

Mr. OTTER. Isn't that an assessment that then we should include and have to make?

Mr. MORTON. Yes.

Mr. OTTER. OK. I agree. Is it "Knopman"?

Ms. KNOPMAN. Yes.

Mr. OTTER. Ms. Knopman, it was your testimony that you have given on this panel that I was referring to in many cases to the other panel. And I am once again using this as a blueprint for some of my questions.

Did you agree or disagree with the Bureau of Land Management's response to my question to them relative to those four key areas?

Ms. KNOPMAN. Well, the purpose of our proposed methodology is to get at the very points that you raised in your line of questioning; which is that there is relevance in the arena of public policymaking for understanding economic viability: wellhead costs, and the transportation and infrastructure costs.

This is what we do in all other areas of energy policy, as well as other kinds of development. The President's energy policy itself is, I think, to a large measure, built around notions of economic viability; a certain kind of realism over the next ten, 20, 30 years, of what we can do technologically. So I think these are relevant lines of inquiry.

Mr. OTTER. Madam Chairman, are we going to have a second round?

Ms. CUBIN. Without objection. Go ahead.

Mr. OTTER. Thank you, Madam Chairman. I don't object. Certainly.

[Laughter.]

Mr. OTTER. I have noticed, with some curiosity, that on the front page of your testimony, under all the salutations and everything, it says that, "This statement is based on a variety of sources, including research conducted at RAND. However, the opinions and conclusions expressed are those of the author, and should not be interpreted as representing those of RAND or any of the agencies or others sponsoring its research."

So I guess what I am going to ask you is, who is the "we" that you constantly cite, and "our"? And who is this plurality of people that you constantly cite in your report?

Ms. KNOPMAN. There are eight authors on this report, and I am one of those authors. I can read the names for the record, if you would like.

Mr. OTTER. I would like those names in the record. Madam Chairman, without objection?

[Pause.]

Mr. OTTER. [Presiding.] I guess I am the Chairman.

Ms. KNOPMAN. The authors' names are Tom LaTourette, Mark Bernstein, Paul Holtberg, Christopher Pernin, Ben Vollaard, Mark Hanson, Kathryn Anderson, and myself, Debra Knopman.

Mr. OTTER. OK. And so then this represents not the RAND Corporation; but this then represents yourself and your co-authors' report?

Ms. KNOPMAN. That is right.

Mr. OTTER. But I will tell you, that was very misleading. Because I have been the benefactor of some terrific RAND reports, and seeing that on the front of your testimony copy, and the constant reference to that in here, led me to believe, until I saw the disclaimer—not unlike what I have to put on every one of my political commercials; I hope not with the same result—I would say that it is very misleading.

And I don't mean that necessarily as criticism, but only as a clarification; that if I thought this was the result of RAND's acceptance, and drawing the conclusions that are drawn in this report and in this testimony, then for me—And mostly, it is because I guess I don't know you very well, and I am not familiar necessarily with your work; but I am very familiar with RAND, and it has a high degree of integrity for me. And so for that reason, I guess I might say I was confused.

Ms. KNOPMAN. If I could just clarify, RAND does not have an institutional position on any issue. And that disclaimer is standard, whether someone from RAND would be here talking about national security, or education, or health, or civil justice, or any of the other areas that we work in.

So this is not particular to this study, for this study did go through the RAND peer review and quality assurance process. And beyond these authors, other people at RAND have been involved in the review of this work. But this is standard for all of our work.

Mr. OTTER. OK. We agree then that this is not RAND's production, and RAND has not adopted this? Would RAND offer the same disclaimer that you offered?

Ms. KNOPMAN. RAND offers the same disclaimer on every publication it produces.

Mr. OTTER. OK. I want that made clear, and I want that for the record. And I have to keep talking until the Chairman gets back—which is not hard for me to do.

My next question then goes to the equation that you set up for recovering the cost of development and market access. Are you aware of any company that would invite exploration, or would undertake exploration, that wouldn't make those assessments?

Ms. KNOPMAN. Well, that is precisely our point, that the companies do this. The issue that we address in our proposed method is that some of this information—not at the detailed level that the companies are talking about, but certainly on a basin-wide and regional level—that this is relevant information to be in the public domain for public debate.

And it is not just for decisions that relate to the supply side of the energy equation, but, as I said in my testimony, there are many states, there are private business concerns trying to understand what our energy prospects are in the future, in particular for natural gas. And having some sense of what our resource base is, and what is available at what cost under varying assumptions about cost, under varying assumptions about technology, is very useful information from the perspective of putting together an energy portfolio. So there are multiple users of that kind of economic viability information.

Dr. Mankin is exactly right when he talks about the uncertainties in the economic estimates, as well as the uncertainties in the estimate of what is in the ground, the resource.

Mr. OTTER. Well, the uncertainties of energy supply are certainly going to be reflected in the cost at the marketplace.

Ms. KNOPMAN. Sure. That is right.

Mr. OTTER. The uncertainty right now of a war on terrorism is going to reflect those same costs; the uncertainty of how many people are going to go on vacation; the uncertainty of whether or not the weather is going to be good or bad. You know, we are turning on the air conditioning in Washington, D.C., at an unusually early time of year—even from my short stay here I recognize that—while we just had a beautiful blanket of 12 inches of snow in Idaho. And so there are lots of uncertainties.

But I am not sure if we can make that in a theoretical bubble, near as well as those people who are putting their dollars on the line, and their reputations on the line, and their marketplace holdings on the line, can make that assessment. And having been in business for 30 years, certainly, when I bought potatoes in the spring of the year, when people were putting them in the ground—long before the well was drilled—and I had to pay $5 a hundredweight for those potatoes, I had to speculate pretty much, and make a scientific—I won't finish the rest of that—make a scientific guess on what McDonald's was going to pay in November. And so making those assessments is one of the major risks in markets.

And they labor to an exhaustive state sometimes, trying to make sure that that assessment is right. Because all the stockholders, their future viability in business all depends upon that. So I understand what it takes to develop an oil field.

And would you agree, or disagree, that it is more economically viable to drill fewer wells and fewer explorations, as was suggested in your report, with combining the public lands with the private adjacent holdings? Would you agree, or disagree, that it is less costly to drill fewer wells than more wells?

Ms. KNOPMAN. I actually can't speak to that question. Our concern has to do with the resource assessment itself and understanding the available resource under different cost scenarios. These are planning scenarios for public land managers, as well as states planning their own energy futures. They need a better understanding of what the possibilities might be, given all of these uncertainties.

We don't stop making estimates, just as you didn't stop making estimates of what the market might look like at the time you were ready to harvest your crop.

Mr. OTTER. But I want you to know, the United States Department of Agriculture didn't make that assessment. Because most of the time, they were wrong. They didn't have their checkbook on the line. And what they had on the line was trying to create a market suggestion of what was going to happen down the line.

We have seen it happen in cattle, we have seen it happen in all kinds of agricultural commodities, where the report in January, February, or March, whether it is orange juice or cattle or potatoes, says one thing; yet the marketplace, from all other kinds of stimulations or inhibitions, has something else that is going to happen. If I had taken that marketplace report and used that as my business plan, I would have been in serious trouble, and I would have passed up a lot of opportunities.

But from your report, I assess that economic viability is important. And I also know from my old days in the drilling business, in the oil business, that it costs a lot of money to drill one well. And it costs twice as much money to drill two; and three times as much, operationally, to drill three or four or five.

And so it would seem to me that if we can assess a resource, a sizable resource, that you can drill one well, instead of ten or 20 or 30, that that is the resource that we ought to retract to, that is the resource that we ought to go to.

Ms. KNOPMAN. Yes, well, I think you are right. And I think part of the advantage of having this out for public debate is to gain some notions of understanding. We are not suggesting that there will be a single estimate of what the viable resources are going to be. There are going to be ranges. Those ranges are going to be based on assumptions that will be clearly defined, as well as showing how these things vary over time.

Mr. OTTER. So then, having said that, would you agree or disagree—and I am sure you have heard the rumors, or at least invited listening to them—that for every one oil well we would drill in ANWR, we would have to drill about 30 or 40 or 50 in the Continental United States? Do you agree or disagree with those nonpeer-reviewed rumors?

Ms. KNOPMAN. I haven't looked at them. I haven't analyzed it. And I am not going to hazard a guess on what the value of information is, which is what you are really talking about when you go and put in a well.

I will say—and Dr. Mankin's testimony and Mr. Seegmiller's testimony also addressed this—there are multiple ways to find out, to learn about, or make estimates of the resource in the ground. We have remote sensing techniques. We have a number of non-intrusive methods besides the drilling. But in some cases, drilling is the only way that you will get the kind of additional information you need to make a more reasoned judgment about whether to proceed with development or not.

We don't have a position on whether or not exploration should or should not proceed. We are only saying that we think there are multiple uses and multiple public benefits of having some credible economic estimates, estimates of economic viability, out on the table as we are thinking about our energy future.

Mr. OTTER. Well, let me just conclude, and perhaps I am not even soliciting a response to this, Madam Chairman. But let me just conclude that my feeling is, all other things being equal, probably the best people making the assessment on the economic viability are the people that are going to pay for it. Thank you, Madam Chairman.

Ms. CUBIN. [Presiding.] The Chair would like to now put four documents into the record, without objection of course. Two of them will be additional statements by Dr. Goerold, who is not here today.

Ms. CUBIN. And a statement of the American Petroleum Institute.

[The prepared statement of the American Petroleum Institute follows:]

Statement of the American Petroleum Institute

The American Petroleum Institute (API) welcomes this opportunity to present the views of its member companies on the methods of resource evaluation employed by the United States, and the role of these methods in Federal policies affecting access to energy resources on Federal lands. API is a national trade association representing more than 400 companies engaged in all sectors of the U.S. oil and natural gas industry, including exploration, production, refining, distribution, and marketing.

We are gratified that this Committee appreciates the importance of the Federal lands in our nation's future energy supply. We applaud the Bush Administration for including access to Federal lands in its review of energy policy by a Cabinet-level task force on the subject, and we are encouraged that you and other Members of Congress of both parties are putting access to those lands high on your agendas.

Today, we are asked to comment on the methods of resource evaluation employed to guide decisionmaking related to energy resources located on Federal lands. A number of recent studies, such as those by the National Petroleum Council in 1999 and by the Department of Energy in 2001, have made significant progress in quantifying the restrictions currently imposed on resource development on these lands. Ongoing studies mandated by Congress promise to further contribute to this pioneering effort to inventory the volumes and accessibility of energy resources on Federal lands. We applaud these efforts.

We also recognize that there are a number of unanswered questions raised by the results of these studies. These questions form an agenda for a new round of research that builds on the efforts completed and ongoing. This agenda needs to be put in place promptly. We are encouraged by Secretary Abraham's recent call to the National Petroleum Council for a new study of natural gas, which provides a forum to do precisely that. But we are also concerned with a number of recent efforts that attempt to fill these unanswered gaps with implausible assertions aimed at discrediting the results completed to date. In this testimony, we lay out a view of what we regard as a legitimate agenda for such future research. We also challenge the assertions made to discredit the work to date, particularly the claims made by the Wilderness Society and by RAND in recent statements and studies.

The NPC and DOE studies have pioneered new ground

It is our belief that the analysis prepared by the NPC in 1999 and in several DOE studies of the Rocky Mountains since that time have been pioneering efforts which have greatly improved the information base supporting Federal land use decisions affecting energy supply. However, it is particularly difficult to quantify the constraints applied to gas resources on Federal multiple use land in the Western states. Approximately 205 million acres of Federal lands in these states are under the control of two Federal agencies with broad discretionary powers. The Bureau of Land Management (BLM), whose land management planning authority is derived from the Federal Land Policy and Management Act (FLPMA) of 1976, and the U.S. Forest Service (USFS), whose jurisdiction is derived from the National Forest Management Act, administer these Federal, non-park lands. Both agencies are required to manage most of these lands under the congressionally mandated concept of multiple use. Yet, BLM and USFS discretionary actions have withdrawn Federal lands from leasing, and long delayed other leasing decisions and project permitting.

Prior to the 1999 NPC study, there was little information available quantifying the significance of these restrictions. We knew that the Rocky Mountains were one of the areas of the U.S. with the greatest potential, containing an estimated 346 TCF of remaining technically recoverable gas, and we knew that much of this resource was on Federal land. We also knew what lands were available for lease. However, we did not have a clear idea of how exactly access restrictions affected the producibility of the lease.

Often getting a lease is not the most significant problem for producers. Difficulties in acquiring permits to drill wells on onshore government lands and overly restrictive lease stipulations are also responsible for limiting natural gas production. These are restrictions, such as "no surface occupancy" or seasonal stipulations, that go above and beyond the normal environmental stipulations and can prevent economic development of the lease without commensurate environmental benefit. The NPC study revealed that almost half of the untapped natural gas on multiple-use government lands in the Rockies is in areas either off limits or restricted by this type of stipulation laid down by one Federal agency or another.

Likewise, the U.S. Forest Service recently banned our companies from exploring for oil and natural gas on promising government lands when it published rules to bar road building on nearly 60 million acres in the Forest System that, according to a Department of Energy study, could hold 11 trillion cubic feet of natural gas. Furthermore, the roadless rule case illustrated how Federal land use actions have disregarded energy potential as an important consideration. In the Rocky Mountains, access to about 83% of the affected gas resource could have been preserved by less than a 5% reduction in the roadless acreage. It was not.

But the NPC study contained a dual message, leaving a key question unanswered

While it suggested that there was a large volume of gas resources on Federal lands subject to restriction, it also identified a much larger volume of resources (>1000TCF) on property not subject to such restriction (either because it is not on Federal land or because it is not subject to access restrictions). This leaves open the question of whether, or to what extent, the identified access constraints are likely to be binding. To answer this question would require an explicit characterization of the relative cost of different components of these resources. That is, unless the restricted areas have some cost advantage over unrestricted areas, they will not be developed even if the restriction is removed.

Recent challenges have suggested that access constraints are not binding

This gap in our information has been exploited by those who do not believe greater access to government lands is needed to develop domestic energy supplies and enhance our security. Two examples of such efforts are recent statements by the Wilderness Society and by RAND.

Wilderness Society.

The first example was presented by the Wilderness Society in testimony before this committee and in a study submitted for the record last year. That statement concluded that only a small percentage of BLM lands in five western states is off limits to leasing and development. For example, while the numbers presented by the Wilderness Society do show that only about 3.5 percent of the BLM lands in Wyoming, Utah, New Mexico, Montana, and Colorado is strictly off limits to development, oil and gas resources in those states are not distributed uniformly across BLM lands. Specifically, while the Wilderness Society says only 3.5 percent of BLM lands are off-limits, the NPC study identifies another 3.2 percent that are subject to No Surface Occupancy. The NPC study indicates that this 6.7 percent of BLM

lands represents 15 percent of the BLM natural gas resources, which are either off-limits or significantly impinged.

More important, however, is the role of non-standard lease stipulations. The Wilderness Society's data show that seasonal and other non-standard stipulations restrict access to an additional 32 percent of BLM lands. However, this impacts access to 47 percent of the natural gas resources estimated to exist on BLM lands in the Rockies. When all of these restricted and off-limit BLM lands are combined they total 38.7 percent, affecting 62 percent of the natural gas resources.

Further, BLM is not the only Federal land management agency making such restrictions. The U.S. Forest Service, the Bureau of Indian Affairs and the departments of Defense and Energy in their computation of Federal multiple-use lands that are restricted to oil and gas development. In total, the National Petroleum Council estimates that some 137 Tcf of natural gas resources lie beneath Federal land in the Rockies that is either off limits to exploration, or heavily restricted. This is 48 percent of the natural gas on Federal land in the region, equivalent to the amount of gas needed to heat 120 million homes for more than 20 years.

This does not include the more than 11 trillion cubic feet (Tcf) of natural gas that was summarily placed off limits in 2000 alone by the USFS "Roadless" rule.

But stipulations are not the only impediments to bringing the oil and natural gas to America's consumers. Inadequate agency resources in many BLM offices and required but outdated resource management plans often make it difficult to get drilling permits, seriously delaying viable projects for up to 100 days, or sometimes years. In the Rawlins, Wyoming BLM office, for example, thousands of Applications for Permits to Drill are awaiting action because of manpower shortages. In the Buffalo, Wyoming office, thousands more are not being accepted by BLM because of limitations of the resource management plans (RMP) for the area. This is because the "Reasonable Foreseeable Development" (RFD) figures, estimates of future development, failed to recognize the interest in developing coal bed methane (CBM). Updating these RMPs and RFDs takes the BLM two or more years to complete, thus preventing any further oil and gas activity in that area until the plans are finished.

RAND.

The recent Rand Issue Paper, "A New Approach to Assessing Gas and Oil Resources in the Intermountain West," provides another, more serious, challenge to the significance of the need for improved access to Rocky Mountain gas resources. It challenges the principal conclusions regarding access made by the 1999 NPC study, and the conclusions likely to come out of the ongoing Energy Policy and Conservation Act (EPCA) study being conducted by ARI. The principal conclusion of the RAND study is that these efforts at quantifying restrictions have grossly overstated the access problem, by assuming that the technically recoverable resources under such restriction would in fact be developed without the restriction. RAND asserts, based on resource economics developed by USGS in connection with its 1995 national assessment, that only a small fraction of the technically recoverable resource is actually economically viable, so that many of the "constraints" discussed by NPC and the upcoming EPCA study are not in fact binding.

While it is true that the NPC and other efforts cited do not present a full comparison of the relative cost of the abundance of resources identified in those studies, it does not follow that those studies have overstated the effect of access constraints, as RAND maintains. In fact, by its own admission, the RAND study rests on shaky foundations. It is hard to tell whether the conclusions presented are even conclusions at all. Some of the text seems more consistent with the language of a proposal for study rather than conclusions drawn from a study. For example, after presenting conclusions based on the USGS 1995 cost analysis, the authors caution the reader to "Note that these results do not necessarily reflect RAND's analysis. The costs of exploring and developing gas and oil deposits in the Rocky Mountain Region are decreasing with technological advances. Our economic analysis will use different data and assumptions and may produce different results." While the study cites a longer RAND study with a 2001 publication date, this earlier study is not included on RAND's website list of publications, and a call to one of the study's authors revealed that the citation was in fact an error. The cited study has not yet been published or even completed.

USGS itself has produced different results in recent years as it redoes its national assessment. In the Powder River Basin, for example, the USGS has already increased its estimate of the basin's technically recoverable CBM resources to 14.26 Tcf, up from 1.11 Tcf in 1995. Finally, it should be noted that the technically recoverable resource concept used both by ARI in its analysis and by NPC in its 1999 study are not the same as that used by the USGS, but are in fact concepts much closer to that of economically viable resources that RAND proposes.

But the conclusion of the RAND study is highly implausible given recent experience

The RAND study fills the gap left by the NPC study with a particularly implausible assertion, namely that the bulk of the unconventional Rocky Mountain gas is likely to be uneconomic relative to alternative supplies elsewhere. But the experience of the past decade suggests just the opposite. That is, the experience suggests that the unconventional resources of the Rockies enjoy a significant economic advantage over gas resources elsewhere.

The Rockies have been the most dynamically changing portions of the domestic resource base. For example, coal bed methane production was negligible prior to the 90s, but by 2000 accounted for 8% of domestic gas production and 60% of the growth in total US gas production during the 90s. The basin has been undergoing a boom as producers increase their understanding of the techniques needed to produce the gas. The number of producing wells increased to 6,469 in July 2001 from 515 in July 1998. Production in July 2001 in the Wyoming portion of the basin reached 784 million cubic feet per day, a nearly 40-percent increase over July 2000 and a 190-percent increase over July 1999.

As of July 2001, the basin contained less than 15 percent of the 50,000 wells that are believed to be needed to fully tap the resource. Based on the productivity of the wells drilled to date, this would mean that the basin could produce over 5 billion cubic feet per day, more than the capacity of the proposed pipeline that would bring gas from Prudhoe Bay to the Lower 48 States. A major impediment to attaining this potential are the delays in the completion of the Powder River basin CBM environmental impact statement.

Given these facts, it simply seems implausible to assert that only a small portion of the resource is expected to be economic or that the constraints are not likely to be significant. In fact, given the dominance of the area in recent growth, it seems far more plausible to conclude that such areas possess an economic advantage over alternatives.

There is a legitimate need for further study

The NPC study broke much new ground in exploring the potential role of access to Federal lands in the development of new US gas supply, but it left unresolved a key question as to the significance of the constraints it identified. To resolve this question, the next logical step should be to identify the cost characteristics of each of the key areas of the resource base. The RAND study makes no useful contribution to plausibly closing that gap. Identifying the relative cost of the restricted areas relative to the unrestricted areas is in fact a legitimate research issue that would enhance the value of the 1999 NPC study. As the NPC considers future extensions of its natural gas research, evaluating these relative costs should be seriously considered within their research agenda.

Ms. CUBIN. And the RAND report.

[NOTE: The report of RAND Science and Technology submitted for the record has been retained in the Committee's official files. The report is accessible from the RAND home page, http://www.rand.org]

Ms. CUBIN. So the record will be held open. These will be placed in the record, but the record will be held open 10 business days after this, if there are any remarks that you wanted to make in regard to those studies.

I really sincerely thank the witnesses for their valued testimony, and the members for their questions. Members of the Subcommittee may have some additional questions, as I stated before; in which case, they would like to send these questions to you in writing. And we will hold the hearing record open for 10 business days for those responses.

If there is no further business then before the Subcommittee, the Chairman again thanks the members and the staff that were here. And the Subcommittee hearing is now essentially adjourned.

[Whereupon, at 12:29 p.m., the Subcommittee was adjourned.]

[A statement submitted for the record by Jeffrey Eppink, Vice President, Advanced Resources International, follows:]

ADVANCED RESOURCES INTERNATIONAL

APRIL 29, 2002

The Honorable Barbara Cubin
Chairwoman
Subcommittee on Energy and Mineral Resources
Committee on Resources
U.S. House of Representatives
1626 Longworth House Office Building
Washington, DC 20515

Dear Representative Cubin:

I attended the hearing held by your Subcommittee on April 18, 2002 on "Oil and Gas Resource Assessment Methodology" and would like to take the opportunity to comment on testimony and supporting documents submitted by Dr. Thomas Goerold. The information provided by Dr. Goerold addresses work performed by my firm, Advanced Resources International, for the U.S. Department of Energy. I would appreciate having this letter and its attachment made a part of the hearing record.

While we welcome discussion on these issues, we believe many of the conclusions reached by Dr. Goerold to be inaccurate and a more thorough examination of the issues shows our work to be valid. We document multiple, representative examples in our attachment by way of illustration.

If you have any questions or if you or your staff wishes to discuss any of the foregoing, please do not hesitate to contact me at (703) 528–8420 or via email at jeppink@advres. com.

Sincerely,

Jeffrey Eppink
Vice President

Advanced Resources International Comments on Goerold Testimony and Documents for Subcommittee Hearing on April 18, 2002, "Oil and Gas Resource Assessment Methodology"

Arguments Concerning the Importance of Domestic Production. The comment in Goerold's testimony[1] is made: "oil and gas imports are expected to become increasingly cheaper to consume than domestically produced energy". This statement is incorrect. Because oil (and increasingly natural gas) is a fungible commodity, its price is set not on the basis of domestic production, but in the worldwide market by entities such as OPEC. Quite simply, if the costs associated with domestic production are too high, domestic resources will not be produced. This argument cannot be used, therefore, as a basis for obviating domestic production—production levels are set in the marketplace.

Further, the testimony argues that domestic production need not be increased, stating: "there are two disadvantages to exclusively consuming domestic oil" [emphasis ours]. It is widely recognized that domestic U.S. oil production will never again be able to satisfy growing U.S. demand as long as oil remains the primary transportation fuel. Goerold then seems to argue that oil resources should be saved for future consumption, but does not argue that they should not be produced. If that is the case, the issue becomes one of timing, not about whether domestic oil (and gas) should be produced.

De--emphasis of Natural Gas. Consistently, we note, the Goerold's documents emphasize domestic oil production issues rather than a more balanced view of oil and gas production. At the conclusion of his testimony, Goerold states: "The most-effective and least intrusive energy policies that this country should pursue [would include getting] the most energy out of currently producing oil and gas fields using enhanced oil recovery (EOR)" [emphasis ours].

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[1] "Testimony of W. Thomas Goerold, Ph.D., Resource Economist, Owner of Lookout Mountain Analysis Before the Subcommittee on Energy and Mineral Resources Committee on Resources United States House of Representative", Lookout Mountain Analysis, April 18, 2002.

On a thermal basis, over half the energy from domestically produced oil and gas comes from natural gas. Further, while we agree that EOR is needed (typically 30 to 40 percent of the oil is left in the reservoir), the same is not true for natural gas, where generally about 70 percent of the resources in a field are recovered. At the same time, depletion rates in natural gas reservoirs are increasing. In the Gulf Coast of the U.S. depletion rates of 40 percent per year can occur, and the average size of the new fields discovered is decreasing.

Goerold also asserts[2] "After hitting a low of 18.6 Tcf of production in 1999, natural gas production increased by 0.7 Tcf in 2000, with significant additional production increases likely as time goes on" [emphasis ours]. It is not at all clear that domestic natural gas production is increasing despite significant increases in drilling and, in fact, recent data from the Energy Information Administration (EIA)[3] indicate that natural gas production is not increasing, but has flattened. It is unclear what the long-term trend will be.

Given the accelerating depletion of natural gas resources in the Gulf Coast[4], the Nation looks increasingly toward the deepwater Gulf of Mexico and the Rocky Mountains to provide potential supply. And for consuming states such as California, the Rockies represent a viable potential source of natural gas for power generation needs. So natural gas is extremely important and leads us to discussion of the "roadless areas" of the Rocky Mountains.

Resources Associated with Roadless Areas. Advanced Resources estimates, on a thermal basis in major basins in the Rocky Mountains, over 85 percent of the oil and gas resources are natural gas. Rocky Mountain natural gas resources are overwhelmingly (over 90 percent) "unconventional" in nature (i.e., "tight gas" and coalbed methane). Thus, any discussion regarding these Rocky Mountain resources is essentially a discussion about unconventional natural gas, which is why we emphasized natural gas in our roadless analyses.[5]

In our analyses, our study area comprised the Forest Service's roadless and "special designated" areas (IRAs and SDAs), as opposed to the whole of the Rocky Mountain regions. We find Goerold's emphasis on the whole of the Rocky Mountain region to be misleading regarding the conclusions he draws concerning the size of the resource.[6]

Regarding methodology[7], we agree with Goerold that use of a homogeneous distribution of resources is a reasonable assumption, especially given the preponderance of unconventional natural gas resources in the Rockies, with their distributed nature of occurrence. Regarding the slope analysis, Goerold contends that this introduces an overestimation bias into our calculations. We fail to see how this could be true, given that, to account for slope variability, we used a lower resource estimate than would otherwise be the case. We believe the confusion may be that Goerold is failing to recognize that we made high, medium, and low estimates.

Concerning the rate of technology change, use of technology improvements is an empirical observation and is a commonly recognized aspect of resource development economics (and in fact is modeled as such in the EIA's National Energy Modeling System)[8]. It is specious to think that, were roadless areas open to development, such technology improvement would be applied elsewhere, but would not be applied in roadless areas. In fact we maintain, that increased pressure would be brought to

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[2] "A Brief Examination of the Adequacy of Future U.S. Natural Gas Infrastructure and Resources and The Role of Public Lands in U.S. Natural Gas Production, A Report to the Wilderness Society", by Goerold, Ph.D., W. Thomas, Lookout Mountain Analysis, June 18, 2001.

[3] Energy Information Administration, see the DOE website: http://www.eia.doe.gov/pub/oil—gas/natural—gas/data—publications/natural—gas—monthly/current/txt/ngprod mo.txt, 2002

[4] Energy Information Administration, Accelerated Depletion: Assessing Its Impacts on Domestic Oil and Natural Gas Prices and Production -- Executive Summary, see the DOE website: http://www.eia.doe.gov/oiaf/servicerpt/depletion/, 2000

[5] "Undiscovered Natural Gas And Petroleum Resources Beneath Inventoried Roadless And Special Designated Areas On Forest Service Lands, Analysis And Results" (see the U.S. DOE website http://www2.fossil.energy.gov/oil—gas/reports/roadless/ari—112000.pdf.), 2000 and "Economically Recoverable Natural Gas Resources Beneath Inventoried Roadless Areas On Forest Service Lands, Analysis And Results" (see the U.S. DOE website http://www2.fossil.energy.gov/oil—gas/reports/roadless/ari—113000.pdf.), 2000

[6] "Examination and Critique of ARI Report: Undiscovered Natural Gas And Petroleum Resources Beneath Inventoried Roadless and Special Designated Areas on Forest Service Lands Analysis and Results, with Additional Discussion of U.S. Geological Survey and National Petroleum Council Reports", by Goerold, Ph.D., W. Thomas, Lookout Mountain Analysis, undated, pp. 7–13.

[7] Ibid., pp. 13–15

[8] EIA, Annual Energy Outlook 2002 with Projections to 2020, (see the EIA website: http://www.eia.doe.gov/oiaf/aeo/appg.html.), 2001

bear to use advanced technology on such oil and gas developments to meet environmental requirements.

Further, we do maintain, in contrast to the USGS analysis cited by Goerold,[9] that drilling "sweet spots"[10] will increase economically recoverable resources. Goerold correctly notes that the USGS used a simplifying assumption that ignores "the localized richness of some areas within each play." However in the real world, sweet spots do occur. According to Goerold's logic, the Jonah natural gas field, an unconventional field located in southwestern Wyoming producing over 700 million cubic feet of gas each day (enough to supply Los Angeles on most days), should not exist.

Finally, Goerold asserts[11] "A primary ARI assumption is that any resources underlying IRAs would not be producible without building access roads within the IRAs." We believe this to be true and do not believe that directional drilling would be used extensively beneath roadless areas for exploration. As Goerold asserts, while it is true that industry can directional drill 5 or 6 miles, this is not a practice in exploration settings, especially in the Rockies.

Once a discovery is established, it could be developed with directional drilling. However, if one makes the general statement that long-range directional drilling is applicable in assessing roadless areas and wants to apply that to a 5 to 6 mile accessibility rim within those areas, it is equal to saying that the typical discovery in the roadless areas will be developed with a long-range directional drilling, which is clearly not the case, even if one were to use an (untenable) aggressively advancing technology scenario. We do recognize that our roadless analyses could be refined by modeling use of directional drilling, but based upon discussions with Federal officials and industry operators, the appropriate distance would be about ′ mile.[12]

In conclusion, while we believe Goerold's testimony and documents raise some interesting points, we do not believe that it invalidates the basic conclusion that sizeable quantities of natural gas resources can be associated with roadless areas.

[A letter and paper submitted for the record by Mr. William Whitsitt, President, Domestic Petroleum Council, follow:]

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[9] USGS, "Economics and Undiscovered Conventional Oil and Gas Accumulations in the 1995 National Assessment of U.S. Oil and Gas Resources: Conterminous United States", 1998

[10] Op. cit., p. 17.

[11] Op. cit., p. 18.

[12] Federal Lands Analysis, Natural Gas Assessment, Southern Wyoming and Northwestern Colorado, Study Methodology and Results, June 2001, available on the DOE website: http://fossil.energy.gov/techline/tl—ggrb—gas.shtml.

DOMESTIC PETROLEUM COUNCIL

April 24, 2002

The Honorable Barbara Cubin
Chairman
Subcommittee on Energy and Mineral Resources
Committee on Resources
U.S. House of Representatives
1626 Longworth House Office Building
Washington, DC 20515

Dear Chairman Cubin:

It is important to address a number of incorrect and misleading points made in testimony at the hearing held by your Subcommittee on April 18, 2002 on "Oil and Gas Resource Assessment Methodology". As a result, I would appreciate having this letter and its attachment be made a part of the hearing record.

As Ray Seegmiller, Chairman, President and CEO of Cabot Oil & Gas, testified for the large independent exploration and production company members of the Domestic Petroleum Council, some discussions of resource assessment methodologies and findings wind up confusing the issues that must be addressed. The recently-released RAND "issue paper" on *A New Approach to Assessing Gas and Oil Resources in the Intermountain West* about which a RAND witness testified is one example.

The attachment to this letter provides comments on a number of statements made by the RAND authors regarding the National Petroleum Council's (NPC) 1999 study entitled *Meeting the Challenges of the Nation's Growing Natural Gas Demand.* The comments were developed in consultation with members of the NPC study team.

Confusion regarding natural gas and oil exploration and production was apparent in the hearing's written and oral statements of the Wilderness Society representative also. For example, he called for resource assessments in the Rockies to be based on use of "directional drilling" for distances of "3-4 miles". This is unrealistic.

101 Constitution Avenue, NW, Suite 800
Washington, DC 20001-2123
202 742 4300 202 742 4505 (fax)
www.dpcusa.org

This concept may have been a result of an incorrect reading of the information on pages 14 and 15 of Volume I of the NPC Study. The illustration on page 15 used a North Slope of Alaska example to show how the industry's technology has evolved over time.

The geology of the Rockies is more complex that the North Slope of Alaska. As an illustration of the geologic complexity, approximately 85% of the oil and gas resources in the Rockies are found in unconventional "tight" sandstone and coalbed formations, with much more limited opportunity for use of directional drilling.

Finally, targeted reserve sizes matter also. The drilling costs of these long deviated holes, such as those in Alaska, are a much higher than vertical holes. This is due to 1) the more complex (expensive) equipment needed and 2) slower penetration rates. In Alaska this is acceptable because, in a field development setting, the reserve estimates per well bore are substantial. In the Rockies that may or may not be the case in any specific area, and is not the case generally.

Furthermore, while it is true that industry has demonstrated that it can directionally drill 5 or 6 miles, that does not mean that it can be done everywhere. And it is not a viable practice in exploration settings, especially in the Rockies.

I hope these thoughts are useful and that you will not hesitate to let me know if I can provide further information or assistance.

Sincerely,

William F. Whitsitt
President

A Response To The RAND Issue Paper Comments on The National Petroleum Council's 1999 Study on Natural Gas

Recently, the RAND Corporation published an Issue Paper* on the subject of industry access to undeveloped gas resources in the Rocky Mountain Region. The RAND paper is critical of the 1999 National Petroleum Council report titled "Meeting the Challenges of the Nation's Growing Natural Gas Demand" (the NPC Study). The NPC Study and other recent work have shown that access restrictions in the Rockies and elsewhere are a major and growing obstacle to meeting our nation's growing demand for natural gas. The NPC Study further showed the large favorable impact on future gas production and prices that would result from improving access to undeveloped resources.

After consultation with members of the supply team that conducted the NPC study, we have concluded that the RAND Issue Paper makes a number of misleading, out of context, and untrue statements about the NPC Study. The paper reflects several misunderstandings regarding both the approach and conclusions of the NPC Rocky Mountain access study.

It should also be noted that the RAND paper was based on an incomplete study, by RAND's own admission. The authors of the RAND paper have so far only reviewed the work of others on the subject. Because of this, it is misleading to publish conclusions and commentary on land access issues in a manner that suggests that new ground has been broken and that they are offering new information.

The rebuttals to the points that RAND makes on page 3 of its paper are as follows:

Point 1:

RAND Statement: The studies should consider the restricted portion of only the economically viable resource. It is the viable resource that is relevant to understanding the amount of resource that would be produced in the absence of access restrictions".

NPC Response: The NPC study did evaluate both technically recoverable and economic resources. In various scenarios evaluated in the study, NPC found that a high percentage of the assessed undiscovered resource base in the Rockies is either economic now or will become economic through 2015. This conclusion has been verified by the current high level of industry interest in the region and the region's growing gas production. While the NPC Study did not publish price-supply curves, the study used economic viability of new prospects as the primary determinant of future industry activity, reserve additions and production. The NPC study showed that most of the assessed Rocky Mountain volumes are economic to develop, either now or in the near future, and that a large volume of these resources is likely to be in areas where industry access is restricted.

* "A New Approach to Assessing Gas and Oil Resources in the Intermountain West"

NPC evaluated the impact on future activity of increasing industry access and found that greater access and reduced regulatory costs will result in significantly higher gas production. The NPC Increased Access Case used the same economic and financial assumptions as the NPC Reference Case. As shown on Figure S-5, page S-26 of Volume II of the NPC Study, Lower 48 gas production in 2015 would be approximately 1.5 TCF greater with less access restrictions. Regarding the Rockies, gas production in the Rockies Foreland would be 800 BCF greater in 2015 with less access restrictions. To put this in context, this incremental Rockies production would satisfy approximately one-quarter of California gas demand in 2015.

Point 2:

RAND Statement: "The NPC Study failed to include proved reserves in the resource base".

NPC Response: The NPC Study does include the entire resource base, including proved reserves. As shown on Table S-2, page S-11 of Volume II of the NPC study, the NPC estimates that the Rockies resource base is 382 TCF. Of this amount, 36 TCF is proven. However, of the total resource base in the Rockies, 137 TCF is subject to some form of access restriction. The restricted portion of the resource base is a very high percentage of the undeveloped resource base. A large portion of this is completely off limits to exploration.

Point 3:

RAND Statement: "The study should account for the fact that access restrictions are sometimes waived. The studies find that three common lease stipulations are waived in 20 – 30 percent of the time, but the study fails to account for this finding in its preliminary analysis".

NPC Response: It should be noted for the record that the NPC Study did not make the above statement regarding lease stipulations being waived 20 – 30 percent of the time, and to state otherwise is completely untrue. It is our understanding that this statement was made in the other study cited in the Rand Issue Paper. The NPC Study was a landmark report in quantifying the effects of access restrictions in Rockies. Based on detailed analysis of six calibration areas in the Rockies, the NPC Study arrived at three lease classifications and its percentages:

Lease Type	Percentage
Off Limits	9%
Higher Costs Due to Access Issues	32%
Standard Lease Terms	59%

Those areas under Standard Lease Terms were not subject to any access restrictions. Those areas with higher costs were subject to increased drilling costs and drilling delays. The cost penalty was computed as a weighted average of the types of restrictions and mitigation measures that were expected to be encountered in the high cost areas.

While it may be true that access restrictions are sometimes waived, it is often the case that new restrictions are placed on "standard lease terms" and other areas as approvals for drilling are reviewed and granted. The net effect could well be a greater cost penalty than the values used in the NPC Study.

Point 4:

RAND Statement: "The study should account for access restrictions that could restrict pipeline and road development outside the potential drilling areas. These may preclude development even in areas where drilling is otherwise permitted".

NPC Response: It is unclear what is being asserted because it sounds as though RAND is saying that access to Rocky Mountain resources is even lower than what NPC has evaluated.

The NPC Study does consider pipeline and other infrastructure costs. These are accounted for in the model. The model solves for lower wellhead prices in remote areas, to reflect higher transportation costs.

In both the Reference Case and the Increased Access Case, the NPC Study assumes that favorable economics for pipeline augmentation must exist for at least three years before a given pipeline corridor is expanded. This factor was decided upon after consideration of several issues including right-of-way access. In other words it would take time to work out access related right-of-way issues. It should be noted that Rockies gas production in both the Reference and Increased Access Cases is constrained due to limited pipeline capacity.

Point 5:

RAND Statement: "The study should factor in that restrictions on timing apply to drilling only (i.e., drilling permitted only in certain months). Once a well is drilled, there are no restrictions on production or maintenance. Thus normally inaccessible resources can be developed via multiple season drilling and produced year round".

NPC Response: This is precisely what the NPC Study assumes in "High Cost Areas."

As noted above in Point 3, the NPC analysis concluded that 32% of the Rockies is subject to conditions mentioned in the above statement. As discussed in detail on page S-21 of Volume II of the NPC Study, the condition cited above was subject to drilling delays and higher costs.

Concluding Comments

One of the most important conclusions in the NPC study was that the Rocky Mountain region will supply a growing amount of the country's natural gas needs. Therefore, policy makers should weigh carefully the economic and environmental benefits of this growing gas supply against policies that might restrict access to the region's important natural gas resources. We see no new information in the RAND report that rebuts or even challenges this conclusion.

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