THE VAST NORTH AMERICAN RESOURCE POTENTIAL OF OIL SHALE, OIL SANDS, AND HEAVY OILS, PARTS 1 AND 2

OVERSIGHT HEARINGS

BEFORE THE

SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES

OF THE

COMMITTEE ON RESOURCES
U.S. HOUSE OF REPRESENTATIVES

ONE HUNDRED NINTH CONGRESS

FIRST SESSION

June 23, 2005 and June 30, 2005

Serial No. 109-22

Printed for the use of the Committee on Resources

Available via the World Wide Web: http://www.gpoaccess.gov/congress/index.html
or
Committee address: http://resourcescommittee.house.gov

U.S. GOVERNMENT PRINTING OFFICE

22-327 PS WASHINGTON : 2005

For sale by the Superintendent of Documents, U.S. Government Printing Office
Internet: bookstore.gpo.gov Phone: toll free (866) 512–1800; DC area (202) 512–1800
Fax: (202) 512–2250 Mail: Stop SSOP, Washington, DC 20402–0001

COMMITTEE ON RESOURCES

RICHARD W. POMBO, California, *Chairman*
NICK J. RAHALL II, West Virginia, *Ranking Democrat Member*

Don Young, Alaska
Jim Saxton, New Jersey
Elton Gallegly, California
John J. Duncan, Jr., Tennessee
Wayne T. Gilchrest, Maryland
Ken Calvert, California
Barbara Cubin, Wyoming
Vice Chair
George P. Radanovich, California
Walter B. Jones, Jr., North Carolina
Chris Cannon, Utah
John E. Peterson, Pennsylvania
Jim Gibbons, Nevada
Greg Walden, Oregon
Thomas G. Tancredo, Colorado
J.D. Hayworth, Arizona
Jeff Flake, Arizona
Rick Renzi, Arizona
Stevan Pearce, New Mexico
Henry Brown, Jr., South Carolina
Thelma Drake, Virginia
Luis G. Fortuño, Puerto Rico
Cathy McMorris, Washington
Bobby Jindal, Louisiana
Louie Gohmert, Texas
Marilyn N. Musgrave, Colorado
Vacancy

Dale E. Kildee, Michigan
Eni F.H. Faleomavaega, American Samoa
Neil Abercrombie, Hawaii
Solomon P. Ortiz, Texas
Frank Pallone, Jr., New Jersey
Donna M. Christensen, Virgin Islands
Ron Kind, Wisconsin
Grace F. Napolitano, California
Tom Udall, New Mexico
Raúl M. Grijalva, Arizona
Madeleine Z. Bordallo, Guam
Jim Costa, California
Charlie Melancon, Louisiana
Dan Boren, Oklahoma
George Miller, California
Edward J. Markey, Massachusetts
Peter A. DeFazio, Oregon
Jay Inslee, Washington
Mark Udall, Colorado
Dennis Cardoza, California
Stephanie Herseth, South Dakota

Steven J. Ding, *Chief of Staff*
Lisa Pittman, *Chief Counsel*
James H. Zoia, *Democrat Staff Director*
Jeffrey P. Petrich, *Democrat Chief Counsel*

SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES

JIM GIBBONS, Nevada, *Chairman*
RAÚL M. GRIJALVA, Arizona, *Ranking Democrat Member*

Don Young, Alaska
Barbara Cubin, Wyoming
Chris Cannon, Utah
John E. Peterson, Pennsylvania
Stevan Pearce, New Mexico
Thelma Drake, Virginia
Bobby Jindal, Louisiana
Louie Gohmert, Texas
Richard W. Pombo, California, *ex officio*

Eni F.H. Faleomavaega, American Samoa
Solomon P. Ortiz, Texas
Jim Costa, California
Charlie Melancon, Louisiana
Dan Boren, Oklahoma
Edward J. Markey, Massachusetts
Nick J. Rahall II, West Virginia, *ex officio*

C O N T E N T S

	Page
Hearing held on Thursday, June 23, 2005	1
Statement of Members:	
Cannon, Hon. Chris, a Representative in Congress from the State of Utah	39
Prepared statement of	39
Cubin, Hon. Barbara, a Representative in Congress from the State of Wyoming, Prepared statement of	40
Gibbons, Hon. Jim, a Representative in Congress from the State of Nevada	1
Prepared statement of	3
Grijalva, Hon. Raúl M., a Representative in Congress from the State of Arizona	4
Prepared statement of	5
Statement of Witnesses:	
George, Russell, Executive Director, Colorado Department of Natural Resources	51
Prepared statement of	52
Response to questions submitted for the record	59
Godec, Michael, Vice President, Advanced Resources International, Inc.	5
Prepared statement of	8
Response to questions submitted for the record	11
McKee, Michael J., Commissioner, Uintah County, Utah	61
Prepared statement of	63
Response to questions submitted for the record	66
O'Connor, Terry, Vice President, External and Regulatory Affairs, Shell Unconventional Resources Energy	18
Prepared statement of	21
Response to questions submitted for the record	27
Savage, Jack S., President, Oil-Tech, Inc.	14
Prepared statement of	16
Stringham, Greg, Vice President, Markets & Fiscal Policy, Canadian Association of Petroleum Producers (CAPP)	30
Prepared statement of	32
Response to questions submitted for the record	33
Additional materials supplied:	
Department of Energy, Government of Alberta, Canada, Statement submitted for the record	69
Granados, Juan Antonio, President, Shale Oil Information Center, Inc. Statement submitted for the record	49
Mathis, Mark, Executive Director, Citizens' Alliance for Responsible Energy, Statement submitted for the record	75
Smith, Murray, Former Minister of Energy, Canada, Oral statement of	36

C O N T E N T S

	Page
Hearing held on Thursday, June 30, 2005	81
Statement of Members:	
Gibbons, Hon. Jim, a Representative in Congress from the State of Nevada	81
Prepared statement of	82
Grijalva, Hon. Raúl M., a Representative in Congress from the State of Arizona, Prepared statement of	105
Statement of Witnesses:	
Barna, Dr. Theodore K., Ph.D., Assistant Deputy Under Secretary of Defense, Advanced Systems and Concepts, Office of the Secretary of Defense, U.S. Department of Defense	83
Prepared statement of	85
Response to questions submitted for the record	88
Calvert, Chad, Deputy Assistant Secretary for Land and Minerals Management, U.S. Department of the Interior	98
Prepared statement of	99
Response to questions submitted for the record	101
Maddox, Mark, Principal Deputy Assistant Secretary for Fossil Energy, U.S. Department of Energy	90
Prepared statement of	92
Response to questions submitted for the record	95
Additional materials supplied:	
Trent, Dr. Robert, Former Dean, School of Mineral Engineering, University of Alaska-Fairbanks, Statement submitted for the record by Dr. Daniel Fine	120

OVERSIGHT HEARING ON "THE VAST NORTH AMERICAN RESOURCE POTENTIAL OF OIL SHALE, OIL SANDS, AND HEAVY OILS," PART 1

Thursday, June 23, 2005
U.S. House of Representatives
Subcommittee on Energy and Mineral Resources
Committee on Resources
Washington, D.C.

The Subcommittee met, pursuant to call, at 10:03 a.m., in Room 1324, Longworth House Office Building, Hon. Jim Gibbons [Chairman of the Subcommittee] presiding.

Present: Representatives Gibbons, Grijalva, Cubin, Cannon, Pearce, Drake, Jindal, and Costa.

STATEMENT OF THE HON. JIM GIBBONS, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF NEVADA

Mr. GIBBONS. The Subcommittee on Energy and Mineral Resources will come to order.

The Subcommittee is meeting today for the first of two hearings that attempt to set the record straight on the immense resource potential of unconventional oil in North America. Today, we will hear from resource experts, resource producers, and state and local government representatives. Next Thursday, June 30th, we will hear from the Departments of Interior, Energy, and Defense on this.

I would guess that many of you in this room who have been following the energy bill debate on Capitol Hill have heard time and time again the misrepresentation that the U.S. has only 3 percent of the world's oil reserves. This myth, or distortion of the truth, has been used by opponents to a comprehensive energy bill as a means of persuading mainstream media and the American public that the U.S. must reduce its oil use or continue to be held hostage to OPEC imports.

Today, as we discuss North American oil shale, oil sands, and heavy oils, we will learn that the U.S. is in quite the opposite position. We actually have some of the world's largest potential oil resources within our own borders.

According to the Department of Energy, the U.S. alone has 2 trillion—that is "trillion" with a "T"—barrels of oil shale, out of some 2.6 trillion barrels of oil shale found worldwide. In addition, today's

testimony will show the U.S. has 1 trillion barrels of other conventional and unconventional oil resources.

It is my understanding that Saudi Arabia has some 260 billion barrels of proven oil reserves. And so if my math is correct, that means the U.S. alone has almost 12 times more oil than Saudi Arabia. And this doesn't count the vast North American potential of Canada's oil sands.

Competition for global oil resources is fierce, with the likes of China and India continuing their quest for more oil to fuel their burgeoning economies. OPEC has committed to increase production, and has now set their price target at $50 a barrel. And I only say, it wasn't too long ago, as we can all remember, OPEC's price span was set somewhere between $22 and $28 per barrel. Now they have set it at $50 per barrel.

"Should the U.S. continue to send billions of dollars overseas each year to purchase foreign oil?" would be the question we should all ask. I hope no one answered "Yes" to that question. The answer is truly "No," and we should not continue to send billions of dollars overseas each year to pay for foreign oil. The answer "No" is brought to us because we have enough oil of our own here at home; and "No" because we should be spending that money here at home, putting people to work, and securing our own economic and energy future.

The major oil shale deposits, some 1.5 trillion barrels, are located in the western U.S., in the States of Colorado, Utah, and Wyoming. And more than 70 percent are expected to be on federally owned and managed land.

But the U.S. does not have a commercial leasing program in place to unlock this Federal resource potential; which is why I worked with my colleagues on the Committee to include language in the House energy bill to help expedite commercial oil shale production.

So, is commercial oil shale production feasible? I think the answer is "Yes." And we will hear testimony on that feasibility today. Today, oil shale, oil sands, and heavy oils are considered unconventional. And there are detractors out there who would have the American public believe that unconventional oil shale resources are insufficient to provide any real stable supply of oil for our future.

I would simply say that over the years technology and technological advances in the oil and gas industry have proven that unconventional resources of the past become the conventional resources of the future. We can't help but look to our neighbors to the north, where Alberta's oil sands were once just a twinkle in some scientist's eye. Alberta's 1.7-trillion-barrel unconventional oil resource is now producing more than 1 million barrels of oil per day.

I welcome our witnesses today. I look forward to their testimony. At this time, I would like to turn it over and recognize our Ranking Member from Arizona, Mr. Grijalva, for any opening remarks he may have. Mr. Grijalva.

[The prepared statement of Mr. Gibbons follows:]

Statement of The Honorable Jim Gibbons, Chairman, Subcommittee on Energy and Mineral Resources

The Subcommittee meets today for the first of two hearings that attempts to set the record straight on the immense resource potential of unconventional oil in North America.

Today, we will hear from resource experts, resource producers, and State and local government representatives.

Next Thursday, June 30th, we will hear from the Departments of Interior, Energy, and Defense.

I would guess that many of you in this room who have been following the energy bill debate on Capitol Hill have heard time and time again the misrepresentation that the U.S. has only 3 percent of the world's oil reserves.

This distortion of the truth has been used by opponents to a comprehensive energy bill as a means of persuading the mainstream media and the American public that the U.S. must reduce its oil use or continue to be held hostage to OPEC imports.

Today, as we discuss North American oil shale, oil sands, and heavy oils, we will learn that the U.S. is in quite the opposite position—we actually have some of the world's largest potential oil resources within our own borders.

According to the Department of Energy, the U.S. alone has 2 trillion—yes, trillion with a "T"—barrels of oil shale out of some 2.6 trillion barrels of oil shale found worldwide.

In addition, today's testimony will show, the U.S. has 1 trillion barrels of other conventional and unconventional oil resources.

Now, it is my understanding that Saudi Arabia has some 260 billion barrels of proven oil reserves.

If my math is correct, that means the U.S. alone has almost 12 times more oil than Saudi Arabia!

And this doesn't count the vast North American potential of Canada's oil sands.

Competition for global oil resources is fierce with the likes of China and India continuing their quest for more oil to fuel their burgeoning economies.

OPEC has committed to increase production and has now set their price target at $50 per barrel.

Do you remember that not too long ago OPEC's price band was set somewhere between $22 and $28 per barrel?

Should the U.S. continue to send billions of dollars overseas each year to purchase foreign oil?

I hope no one answered "yes" to that question—The answer is "no", we should not continue to send billions of dollars overseas each year to pay for foreign oil.

"No", because we have enough of our own oil here at home.

And "no", because we should be spending that money here at home, putting people to work and securing our own economic and energy future.

The major oil shale deposits—some 1.5 trillion barrels—are located in the Western U.S. in the states of Colorado, Utah, and Wyoming and more than 70 percent are expected to be federally-owned.

But the U.S. does not have a commercial leasing program in place to unlock this federal resource potential, which is why I worked with my colleagues to include language in the House energy bill to help expedite commercial oil shale production.

So, is commercial oil shale production feasible?

I believe the answer is "yes", and we'll hear testimony on that feasibility today.

Today, oil shale, oil sands, and heavy oils are considered unconventional, and there are detractors out there who would have the American public believe that unconventional oil shale resources are insufficient to provide any real, stable supply of oil for our future.

I would simply say that over the years, technological advances in the oil and gas industry have proven that the unconventional resource of the past becomes the conventional resource of the future.

We can't help but look to our neighbors to the north where Alberta's oil sands were once just a twinkle in some scientist's eye.

Alberta's 1.7 trillion barrel unconventional oil resource is now producing more than 1 million barrels of oil per day!

I welcome our witnesses today and look forward to their testimony.

At this time I would like to recognize our Ranking member from Arizona, Mr. Grijalva, for any opening remarks he may have.

STATEMENT OF HON. RAÚL M. GRIJALVA, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF ARIZONA

Mr. GRIJALVA. Thank you, Mr. Chairman. And I join with you in welcoming our witnesses and looking forward to their testimony.

Today's hearing focuses on a potentially untapped domestic energy resource, oil shale and oil sands. Industry experts say oil shale holds great potential, with an estimated 2 to 4 trillion barrels of oil locked in the Green River formation out West. Yet development of the resource has not come to fruition due, I believe, primarily to excessive cost.

While the USGS has estimated there are about 2 trillion barrels of conventional recoverable oil in the world, it has done no estimates for oil shale or oil sand. Oil shale has a history in the western United States that is shaky at best. Many bold promises have been made in the past about oil shale's potential and about the affordability of its production, but few of them have come true so far. As the old saying goes in Colorado, "Oil shale is the fuel of the future, and always will be."

In March of this year, The Wall Street Journal ran a story that reiterated both the huge resource embedded in the shale of the Green River region and the challenges that are involved in extracting oil from the rock.

Today, however, with oil prices at all-time highs, we see renewed interest from industry in developing these resources. A recent Washington Post article on oil shale mining in Canada stated that major companies faced with tougher prospects for developing big, new oil fields around the world are doing what was once unthinkable: sinking billions of dollars into projects to wring out deposits of petroleum buried amid sand and clay.

While there is excitement about the prospects of development of the resource, I join with my colleague Mark Udall of Colorado in urging some degree of caution on the part of the Federal Government. The new technologies being developed to extract or convert shale and sand into oil and gas should be adequately analyzed, and the impacts of developing these resources should be assessed before BLM launches into a full-scale leasing program. Before Congress commits lands or financial resources to oil shale development, there are important issues to consider, such as the potential impacts on water quality and quantity, particularly in such an arid region.

Finally, as we have stated before, we cannot drill or mine our way out of the current energy crisis. As 26 former national security advisors have asserted, we would be better off recognizing the full costs of our continuing and disproportionate dependence on oil from any source.

While there may be nothing wrong with the BLM facilitating oil shale development, I would hope that any taxpayer revenue or support be devoted to energy research and development that would be spent on non-fossil-fuel energy technologies.

With that, I thank the Chairman.

[The prepared statement of Mr. Grijalva follows:]

Statement of The Honorable Raúl M. Grijalva, Ranking Democrat, Subcommittee on Energy and Mineral Resources

Today's hearing focuses on a potentially untapped, domestic energy resource—oil shale and oil sands.

Industry experts say oil shale holds great potential with an estimated 2 to 4 trillion barrels of oil locked in the Green River formation out west, yet development of the resource has not come to fruition due primarily to excessive costs. While the USGS has estimated that there are about 2 trillion barrels of conventional recoverable oil in the world, it has done no estimates for oil shale or oil sands.

Oil shale has a history in the western United States that is shaky at best. Many bold promises have been made in the past about oil shale's potential and about the affordability of its production but few of them have come true so far.

As the old saying goes in Colorado "oil shale is the fuel of the future, and always will be." In March of this year, the Wall Street Journal ran a story that reiterated both the huge energy resource embedded in the shale of the Green River region and the challenges that are involved in extracting oil from rock.

Today, however, with oil prices at all time highs, we see renewed interest from industry in developing these resources. A recent Washington Post article on oil shale mining in Canada, stated that "Major companies—faced with tougher prospects for developing big new oil fields around the world—are doing what was once unthinkable: sinking billions of dollars into projects to wring oil out of deposits of petroleum buried amid sand and clay."

While there is excitement about the prospects of development of this resource, I join my colleague, Mark Udall of Colorado, in urging some degree of caution on the part of the federal government. The new technologies being developed to extract or convert shale and sand into oil and gas should be adequately analyzed and the impacts of developing these resources should be assessed before the BLM launches into a full scale leasing program.

Before the Congress commits lands or financial resources to oil shale development there are important issues to consider, such as the potential impacts on water quality and quantity, particularly in such an arid region.

Finally, as we have stated before, we cannot drill—or mine—our way out the current energy crisis. As 26 former national security advisors have asserted, we would be better off recognizing the full costs of our continuing and disproportionate dependence on oil from any source. While there may be nothing wrong with the BLM facilitating oil shale development, I would hope that any taxpayer revenues devoted to energy research and development would be spent on non-fossil fuel energy technologies.

Mr. GIBBONS. Thank you very much, Mr. Grijalva.

We will now recognize our first panel. Welcome, gentlemen. Mr. Mike Godec, Vice President, Advanced Resources International, Incorporated; Mr. Jack Savage, President and CEO, Oil-Tech, Incorporated; Terry O'Connor, Vice President, External and Regulatory Affairs, Shell Unconventional Resources Energy; and Greg Stringham, Vice President, Markets and Fiscal Policy, Canadian Association of Petroleum Producers.

Gentlemen, welcome. If you will all please rise and raise your right hand, we have a policy to swear in our witnesses.

[Witnesses sworn.]

Mr. GIBBONS. Let the record reflect that each of the witnesses answered in the affirmative. We will begin with Mr. Mike Godec. Welcome, Mr. Godec. The floor is yours. We look forward to your testimony.

STATEMENT OF MIKE GODEC, VICE PRESIDENT, ADVANCED RESOURCES INTERNATIONAL, INC.

Mr. GODEC. Thank you very much, Mr. Chairman. Good morning. I am pleased to address this Subcommittee on the topic of increasing future domestic oil production from oil shale, oil sands, and heavy oil.

As the Chairman stated, our Nation's oil basins are mature and in decline. In the past 20 years, domestic oil production has dropped by 3 million barrels per day; while demand for oil has continued to grow.

However, the problem of declining domestic oil production is not due to lack of domestic resources. Not including domestic oil shale resources, which others testifying today can address more effectively than I, undeveloped domestic oil resources in the ground, or in place, in the U.S. still total over 1 trillion barrels.

These resources include undiscovered conventional onshore and offshore oil; the future growth of already discovered oil fields; stranded light oil resources amenable to carbon dioxide enhanced oil recovery; shallow and deep heavy oil; residual oil in transition zones; and oil sands. These domestic resources could produce an additional estimated 400 billion barrels of future technically recoverable oil, as shown in Table 1 of our written testimony provided to this Subcommittee.

In addition, as stated in the opening remarks, another 2 trillion barrels exist in U.S. oil shale deposits; primarily in Colorado, Utah, and Wyoming, but also in lower-quality deposits in the eastern U.S. Of this, about 400 billion barrels is of relatively high quality, holding more than 30 gallons per ton of shale. Perhaps half of this is technically recoverable, and would be the target for initial development efforts.

All told, this represents approximately 3 trillion barrels of remaining undeveloped oil resource in the U.S., with perhaps 600 billion barrels technically recoverable, if not yet economic.

Again, to put this in some context, according to the U.S. Geological Survey, current estimated recoverable oil reserves worldwide total about 2.3 trillion barrels. This includes the vast reserves in the Middle East and the former Soviet Union, and the recoverable proportion of the massive heavy oil and oil sands deposits in Canada and in Venezuela.

In this light, the U.S. petroleum industry faces the challenge of developing and utilizing new concepts and technology for economically producing these challenging and more costly remaining domestic oil resources.

Now let me focus more explicitly on just two of the categories of domestic oil resources that are the topic of today's hearing: heavy oil and oil sands. The U.S. still has very large volumes of undeveloped heavy oil and oil sands—sometimes called "tar sands"—estimated at about 180 billion barrels originally in place. Of this, about 100 billion barrels exist in heavy oil reservoirs, with another 80 billion barrels in oil sand prospects. However, unlike oil shale, this resource is quite geographically dispersed; located in California, Alaska, Utah, Alabama, Texas, Wyoming, Arkansas, Kentucky, Louisiana, Mississippi, and Missouri.

Application of thermal enhanced oil recovery technology, particularly steam injection, has enabled the U.S. industry to already recover and produce a significant portion of the domestic heavy oil resource from the geologically most favorable, shallow portion of the resource base, primarily in California and Alaska.

For example, in 2003, heavy oil production in California provided over 500,000 barrels of production per day; and Alaska produced

27,000 barrels per day. To date, we have recovered about 17 billion barrels of heavy oil, with about 2 billion barrels remaining in proved economic reserves.

However, despite these impressive efforts by industry, the great bulk—over 160 billion barrels of this resource—is not recoverable with today's technology. But based on our past work, we estimate that with—another 30 billion barrels could become technically recoverable with modest advances in oil recovery technology.

An important characteristic of heavy oil and bitumen oil sands is that nature, over geologic time and with heat and pressure, has already converted these resources from a geologically immature hydrocarbon in the source rock, such as kerogen in oil shale, to crude oil. As such, compared to oil shale, nature has taken care of half of the challenge.

Still, because of its high viscosity, the remaining heavy oil and oil sand resource is essentially immobile. Injection of heat or solvents, or the direct mining of the resource, is still required to efficiently recover and produce the heavy oil and tar sands.

Given their relative development challenges, however, and also their likely timing of potential future contribution to domestic supplies, a prudent technology development strategy would be one that focuses on the commercial production of, first, heavy oil, then oil sands, and then oil shale.

The introduction of advanced heavy oil and oil sands technology, including technologies such as horizontal wells and CO2-based enhanced oil recovery technologies, could provide a valuable first start. In addition, adaptation of new technologies being tested and applied in Canada could help further unlock the domestic heavy oil and oil sands potential.

Of particular value would be the development and introduction of state-of-the-art, zero-emission heavy oil and oil sands recovery processes that could productively use the byproduct CO2 that would otherwise be emitted to the atmosphere. Not only would this achieve a positive net energy balance and increase domestic production, but it would provide one more market-based technology option to encourage reducing CO2 emissions to the atmosphere.

Several steps could be taken to help overcome the barriers currently facing the development of domestic heavy oil and oil sands resources:

First, reduce current geological, technical, and economic risks through an aggressive program of research and field tests. Optimizing performance of current heavy oil and oil sands recovery practices and expanding their application will help overcome these current risks posed by these technologies.

State-Federal partnerships devoted to technology transfer could also help address these barriers that currently inhibit the application of these technologies. Also, engaging in collaborative Canadian-U.S. efforts, such as sharing technology and conducting joint-funded field research, could help facilitate application of the best technologies appropriate for all North American heavy oil and oil sands resources.

Second, invest in new technology development that could lead to higher oil recovery efficiencies and reduced costs. New models of public-private partnerships focused on developing domestic oil

resources could enable the launching of key field projects to demonstrate higher oil recovery concepts and advanced technologies, along with the zero-emissions recovery processes that I mentioned.

Third, provide risk mitigation incentives to mitigate the impacts of potential drops in oil prices for those producers willing to try new technologies. At the Federal level, recent modifications proposed for the Section 43 EOR tax credit could help accomplish this, as could royalty relief for resources underlying Federal lands.

Finally, update the data and information base on domestic heavy oil and oil sands. The initial studies of the domestic heavy oil and oil sands—the ones still used today by Congress and other energy policymakers and those quoted today in this testimony—were prepared by my co-author and me for the Interstate Oil and Gas Compact Commission nearly 20 years ago. Since then, much has been learned about the domestic resource base, and significant advances in heavy oil and oil sands extraction technology have taken place.

An up-to-date resource and technology study on domestic heavy oil and oil sands could provide insights on formulating policies, initiatives, and technology, for more effectively and efficiently and economically developing this large domestic oil resource.

With these actions, heavy oil and oil sands could provide an additional 500,000 barrels per day of U.S. production within ten years; an additional 1 to 1-1/2 million barrels a day by 2025, particularly from Alaska, California, Texas, Utah, and Wyoming.

Thank you very much for providing me the opportunity to testify before the Subcommittee today.

[The prepared statement of Mr. Godec follows:]

Statement of Vello A. Kuuskraa (vkuuskraa@adv-res.com), President, Michael Godec (mgodec@adv-res.com), Vice President, Advanced Resources International, Inc.

Good afternoon. I am pleased to address the House Subcommittee on Energy and Resources on the topic of increasing future domestic oil production from oil shale, oil sands, and heavy oils.

Our nation's oil basins are mature and in decline. In the past 20 years, domestic oil production has dropped by 3 million barrels per day, while demand for oil has continued to grow. As a result, imports now provide 60% of the oil consumed in the U.S., with serious implications for energy security. In fact, in his recent national address on energy, President Bush stated: "Our dependence on foreign energy is like a foreign tax on the American people. It is a tax our citizens pay every day in higher gasoline prices and higher costs to heat and cool their homes. It's a tax on jobs and a tax that is increasing every year."

However, the problem of declining domestic oil production is not due to a lack of domestic resources. Not including domestic oil shale resources, which others testifying today can address more effectively than I, undeveloped domestic oil resources in the ground (in-place) in the U.S. still total over 1,000 billion barrels. These resources include undiscovered conventional onshore and offshore oil; future growth of already discovered oil fields ("reserve growth"); "stranded" light oil resources amenable to carbon dioxide enhanced oil recovery (CO2-EOR) technologies; shallow and deep heavy oil amenable to thermal and other EOR technologies; residual oil in transition zones; and oil sands. These domestic resources could provide an additional 400 billion barrels of future technically recoverable oil, as shown in Table 1. The U.S. petroleum industry, as the leader in applying exploitation and EOR technology, faces the challenge of developing technology for economically producing this more challenging—and more costly—remaining domestic oil resource.

Now, let me focus more explicitly on two of the categories of domestic oil resources that are the topic of today's hearing—heavy oil and oil sands. The U.S. still has very large volumes of undeveloped heavy oil and oil sands (sometimes called "tar sands"), estimated at 180 billion barrels originally in-place. Of this, about 100 billion barrels exists in heavy oil reservoirs, with another 80 billion barrels in oil sands prospects.

However, unlike oil shale, this resource, is geographically quite dispersed, located in California (47 billion barrels), Alaska (44 billion barrels), Utah (19 to 32 billion barrels), Alabama, Texas and Wyoming (each with 5 to 6 billion barrels), and numerous other states such as Arkansas, Kentucky, Louisiana, Mississippi and Missouri,

Table 1. Potential Remaining Undeveloped Domestic Oil Resources

	Original Oil in Place (Billion Barrels)	Technical Recovery Potential (Billion Barrels)
Undiscovered Conventional [1,2]	360	179
Reserve Growth [3,4]	210	111
Stranded Light Oil [5]	280	80
Heavy Oil [6]	100	20
Oil Sands [8]	80	10
Residual Oil in Transition Zones [7]	100	Unknown
Total	**1,130**	**400**

1. Source: USGS National Assessment of Oil and Gas Resources Update (USGS; October 2004) Conventional Oil Resources (40.43 billion barrels) and Continuous Oil Resources (2.13 billion barrels). Oil in–place estimated by assuming 33% recovery efficiency. Assumes 50% recovery efficiency with enhanced oil recovery for undiscovered.
2. Source: Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2003 Update (MMS Fact Sheet, December 2004).
3. Source: Estimates of Inferred Reserves for the 1995 USGS National Oil and Gas Resource Assessment (USGS OFP 95-75L, January 1997). Assumes 50% recovery efficiency with enhanced oil recovery for reserves growth.
4. Source: Assumptions for the Annual Energy Outlook 2004 (EIA, February 2004).
5. Source: DOE/FE Basin Reports, (Advanced Resources, 2005), recoverable from existing and future "stranded" oil resources estimated by Advanced Resources.
6. Source: A Technical and Economic Assessment of Domestic Heavy Oil (V.A. Kuuskraa and M.L. Godec, 1987). Recoverable estimated by Advanced Resources.
7. Source: Preliminary Estimates by Advanced Resources Int'l and Melzer Consulting (2005).
8. Source: Major Tar Sand and Heavy Oil Deposits of the United States (Lewin and Associates, Inc., July 1983). Recoverable estimated by Advanced Resources.

Application of thermal enhanced oil recovery (EOR), particularly steam injection, has enabled industry to recover and produce a portion of the domestic heavy oil resource, from the geologically most favorable, shallow portion of the resource base, primarily in California and Alaska. For example, heavy oil production in California provided 510,000 barrels per day, and in Alaska provided 27, 000 barrels per day (both in 2003). While heavy oil production has been declining in California, it is counterbalanced, somewhat by increasing production in Alaska, Figure 2. To date, we have recovered 17 billion barrels of heavy oil, with 2 billion barrels in proved reserves.

In spite of impressive efforts by industry, the great bulk over 160 billion barrels of the resource in deep heavy oil reservoirs and in oil sands is not recoverable with today's oil recovery technology. Based on our past work, we estimate that another 30 billion barrels could become technically recoverable with advances in oil recovery technology.

Figure 1. Size and Distribution of U.S. Heavy Oil and Oil Sands Resources in the United States

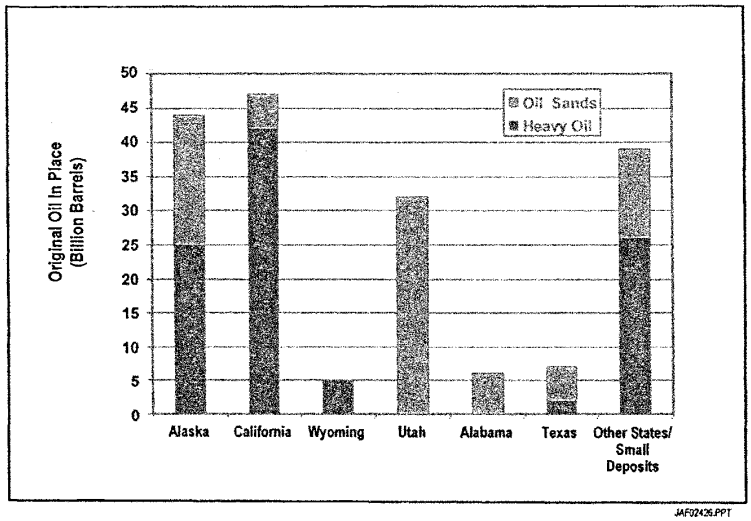
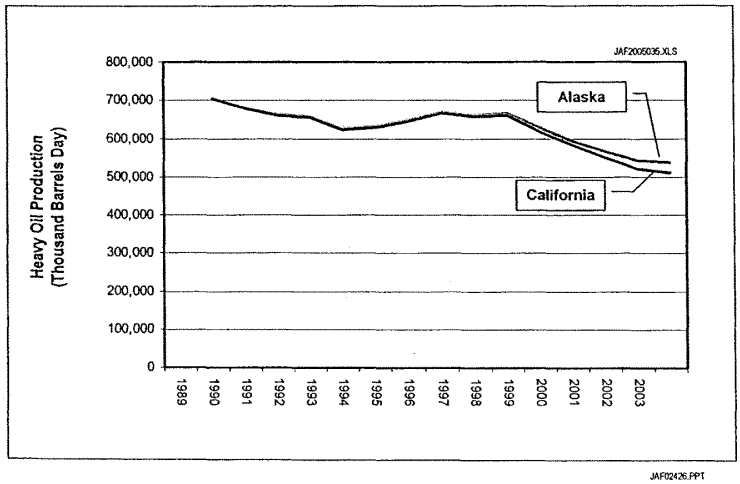


Figure 2. Heavy Oil Production in California and Alaska



An important characteristic of heavy oil and the bitumen in oil sands is that nature, over geologic time and with heat and pressure, has already converted these resources from immature source rock, such as kerogen in oil shale, to a crude oil. As such, compared to oil shale, nature has taken care of half of the challenge. Still, because of its high viscosity (low API gravity), the remaining heavy oil and oil sand resource is essentially immobile. Injection of heat or solvents, or the direct mining of the resource, is required to efficiently recover and produce crude oil from heavy oil and oil sands. Given the challenge, a prudent technology development strategy would be to first address heavy oil, then oil sands, and then oil shale.

Introduction of advanced heavy oil and oil sands technology, including technologies such as horizontal wells and CO2-based enhanced oil recovery technologies, would provide a valuable start. In addition, adaptation of new technologies being tested in Canada, such as SAGD (steam assisted gravity drainage), VAPEX (the use

of a combination of solvent and heat), and the "top down combustion" process, could help further unlocking the domestic heavy oil and oil sands resource potential.

Of particular value would be the development and introduction of state-of-the-art "zero emission" heavy oil and oil sands recovery processes, which could involve an upgrading and refining system involving gasification of heavy oil residue to produce steam, hydrogen, and electricity, while productively using the by-product CO2 that would otherwise be emitted to the atmosphere for recovery of deep heavy oil. Not only would this achieve a positive energy balance, but it would provide one more "market-based" technology option for reducing CO2 emissions to the atmosphere.

Several steps could be taken to overcome the barriers currently facing the development of domestic heavy oil and oil sand resources:

- Reducing current geological, technical, and economic risks could be accomplished through an aggressive program of research and field tests. Optimizing the performance of current heavy oil and oil sands recovery practices and expanding its application will help lower the geological, technical, and economic risks involved with these enhanced oil recovery technologies. This was the pathway used by the DOE and the Gas Research Institute to reduce geologic and technical risks which helped commercialize domestic unconventional gas, that now accounts for over one-third of domestic natural gas production. State-Federal partnerships devoted to technology transfer would help address the barriers that currently inhibit the development and production of domestic heavy oil and oil sands. Also, engaging in collaborative Canadian/U.S. efforts such as sharing technology and conducting jointly-funded field R&D on oil sands and heavy oil could help facilitate application of the best technologies appropriate for U.S. heavy oil and oil sands resources.
- Investments in new technology development would lead to higher oil recovery efficiencies. New models of public-private partnerships focused on developing domestic oil resources could enable the launching of key field projects to demonstrate higher oil recovery concepts and advanced technologies. Moreover, demonstrating an integrated "zero emissions" steam, hydrogen and electricity generation system, that provides "EOR-Ready" CO2 from the residue products from heavy oil and oil sand upgrading and refining, would provide an efficient approach toward future oil recovery.
- Providing "risk-mitigation" incentives to provide protection against sharp drops in oil prices for those producers willing to try new technologies. At the Federal level, recent modifications proposed for the Section 43 EOR tax credits could help accomplish this, as could royalty relief for resources underlying Federal lands. At the state level, severance tax relief could also help provide risk mitigation incentives.
- Update the data and information base on domestic heavy oil and oil sands. The initial studies of domestic heavy oil and oil sands, and the ones still used by Congress and other energy policy makers, and those quoted today in this testimony, were prepared by the two authors of this Congressional Testimony for the Interstate Oil and Gas Compact Commission (IOGCC) nearly 20 years ago. Since these past studies were conducted, much has been learned about the resource base, and significant advances in heavy oil and oil sands extraction technology has taken place. An up-to-date resource and technology study on domestic heavy oil and oil sands could provide insights on formulating policies, initiatives and technology for more effectively developing this large oil resource, helping increase domestic oil production.

With these actions, domestic heavy oil and oil sands could provide an additional 500,000 barrels per day of production in ten years, and an additional 1 to 1.5 million barrels per day of domestic oil production by 2025, particularly from Alaska, California, Texas, Utah and Wyoming.

Thank you very much for providing us with the opportunity to testify before this subcommittee today.

Response to Questions submitted for the record by Michael Godec. Vice President, Advanced Resources International, Inc.

1. *Am I correct in understanding your testimony to be that not counting oil shale, the United States still has one trillion, one hundred thirty billion barrels of oil in the ground?*

Based on data published by the U.S. Geological Survey (USGS) and Minerals Management Service (MMS), 570 billion barrels of oil in the ground exist in undiscovered conventional oil fields and from the future growth of already discovered oil fields ("reserve growth"), assuming traditional oil recovery efficiency.

Adding the "stranded" light oil resources in discovered fields amenable to CO2 enhanced oil recovery (CO2-EOR); shallow and deep heavy oil fields amenable to thermal and other EOR; residual oil in transition zones; and domestic oil sands together provide another 554 billion barrels of resource in the ground.

The sum of these two is one trillion, one hundred twenty four billion barrels of oil in the ground. (This represents a slight modification to the preliminary numbers submitted in our original testimony, which used rounded numbers.) All of these estimates are based on existing resource studies, as summarized (with citations) in Table 1.

2 Am I further correct in understanding that you believe that at least 400 billion barrels of this oil should be able to be produced?

That is correct. We estimate that these domestic resources could provide an additional 400 billion barrels of future technically recoverable oil, again as shown in Table 1. This does not imply that all of this is currently economic to produce, even at today's oil prices. This estimate includes 190 billion barrels of technically recoverable resources, using conventional technology, and 210 billion barrels of oil recovery from "state-of-the-art" EOR technology. Moreover, the EOR recoverable numbers would be significantly higher should technology progress occur for EOR.

3. Do these numbers include any increases for anticipated reserve growth?

Yes, as described in my answer to Question No. 1, the 1,124 billion barrels of undeveloped resources in the ground include the anticipated growth of reserves in conventional oil fields.

Table 1. Potential Remaining Undeveloped Domestic Oil Resources

	Remaining Oil In-Place	Technically Recovery Resources		
		Primary/ Secondary Recovery	Enhanced Oil Recovery	Total
	(Billion Barrels)	(Billion Barrels)	(Billion Barrels)	(Billion Barrels)
Undiscovered Conventional [1,2]	360	119	60	179
Reserve Growth [3,4]	210	71	40	111
Subtotal	**570**	**190**	**100**	**290**
Stranded Light Oil [5]	293	-	80	80
Heavy Oil [6]	81	-	20	20
Oil Sands [8]	80	-	10	10
Residual Oil in Transition Zones [7]	100	-	Unknown	Unknown
Subtotal	**554**	**-**	**110**	**110**
Total	**1,124**	**190**	**210**	**400**

1. Source: USGS National Assessment of Oil and Gas Resources Update (USGS; October 2004) Conventional Oil Resources (40.43 billion barrels) and Continuous Oil Resources (2.13 billion barrels). Oil in–place estimated by assuming 33% recovery efficiency. Assumes 50% recovery efficiency with enhanced oil recovery for undiscovered.
2. Source: Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2003 Update (MMS Fact Sheet, December 2004).
3. Source: Estimates of Inferred Reserves for the 1995 USGS National Oil and Gas Resource Assessment (USGS OFP 95-75L, January 1997). Assumes 50% recovery efficiency with enhanced oil recovery for reserves growth.
4. Source: Assumptions for the Annual Energy Outlook 2004 (EIA, February 2004).
5. Source: DOE/FE Basin Reports, (Advanced Resources, 2005), recoverable from existing and future "stranded" oil resources estimated by Advanced Resources.
6. Source: A Technical and Economic Assessment of Domestic Heavy Oil (V.A. Kuuskraa and M.L. Godec, 1987). Recoverable estimated by Advanced Resources. Adjusted for heavy oil resources produced to date.
7. Source: Preliminary Estimates by Advanced Resources Int'l and Melzer Consulting (2005).
8. Source: Major Tar Sand and Heavy Oil Deposits of the United States (Lewin and Associates, Inc., July 1983). Recoverable estimated by Advanced Resources.

4. Are there any significant differences, other than quantity, between the U.S. oil sands and the Alberta oil sands?

Alberta oil sands are "water wet" while the U.S. oil sands are "oil wet", making the extraction of Albert oil sands considerably simpler. In addition, Alberta oil sands, on average, tend to be a richer (in terms of barrels of resource per acre). Nonetheless, there are some deposits in the U.S. that are of comparable quality to some of the best deposits in Alberta.

We believe much can be learned from cooperating with Canada on their pursuit of advanced oil sand extraction technology, particularly for new in situ oil sand recovery technology.

5. Please prioritize the things that the Federal Government can do to ensure that at least the 400 billion barrels of oil are produced.

The Federal Government, could, in priority order: (1) help reduce the financial barriers associated with applying "state-of-the-art" exploration and production technologies through an aggressive program of field demonstrations and "risk mitigation" actions and incentives to encourage industry investments, (2) encourage increased private R&D investment and/or provide direct Federal R&D focused on developing new, "next generation" technologies that further improve the efficiency and reduce the costs of pursuing U.S. undeveloped oil resources; and (3) update the data and information base on domestic heavy oil and oil sands. Please see further elaboration in our answer to Question 7 below.

6. Looking at the whole range of extra heavy oils and tar sands you cite in your testimony, what do you see as the principal factors impeding development? How would you prioritize attention among these resources and why?

Pursuing undeveloped domestic extra heavy oil and oil sands pose considerable economic risks and technical challenges. The risks and challenges stem from a lack of information on the actual geologic condition of the remaining resource (e.g., the distribution and saturation of the residual oil in the reservoir's pore space), uncertainties on how well oil recovery technology (often adapted from other settings) will perform in a new geologic setting or basin, and the inherent volatility and uncertainty surrounding world oil prices. To date, this combination of geologic, technical and economic risks have posed severe barriers to the full development of the remaining domestic oil resource base, particularly for deep heavy oil and oil sands.

As stated in my oral testimony, an important characteristic of heavy oil and oil sands is that nature, over geologic time and with heat and pressure, has already converted these resources from a geologically immature hydrocarbon in the source rock, such as kerogen in oil shale, to a crude oil. Compared to oil shale, nature has taken care of half of the challenge. As such, a prudent technology development strategy would be one that pursues commercial production of first heavy oil, then oil sands, and then oil shale.

7. What is your view regarding the future of unconventional liquid fuels, vs. conventional petroleum, i.e. what needs to happen before these unconventional oils attract investment? How do you see heavy oil and tar sands developing over the next 20 years?

In my testimony, I stated that the Federal Government could take a series of actions to overcome the barriers currently impeding the development of domestic heavy oil and oil sands resources.

- First, reduce current geological, technical, and economic risks through an aggressive program of field tests and technology transfer. State-Federal partnerships devoted to field tests and technology transfer would help address the barriers that currently inhibit the application of these technologies. Also, engaging in collaborative Canadian/U.S. efforts, such as sharing technology and conducting jointly-funded field R&D on oil sands and heavy oil, could keep developing new technologies appropriate for all North American heavy oil and oil sands.
- Second, invest in research and new technology development toward higher oil recovery efficiencies and reduced costs. New models of public-private partnerships, focused on developing "next generation" oil recovery technologies and launching key field projects to demonstrate these higher oil recovery technologies, would be most important.
- Third, provide "risk-mitigation" incentives to mitigate the impacts of potential future decline in oil prices for those producers willing to try new technologies. At the Federal level, recent modifications proposed for the Section 43 EOR tax credit could help accomplish this, as would royalty relief for resources underlying Federal lands. At the state level, severance tax relief would also provide risk mitigation incentives.
- Finally, update the data and information base on domestic heavy oil and oil sands. In the last 20 years, much has been learned about the domestic resource base, and significant advances in heavy oil and oil sands extraction technology have taken place. An up-to-date resource and technology study on domestic heavy oil and oil sands could provide insights on formulating policies, initiatives and technology for more effectively developing this large oil resource.

With these actions, domestic heavy oil and oil sands could provide up to an additional 500,000 barrels per day of U.S. production in ten years, and an additional 1 million barrels per day by 2025, particularly from Alaska, California, Texas, Utah and Wyoming. Without these actions, the contribution of domestic heavy oil and oil sands to U.S. energy supplies will grow at a substantially slower rate, if at all.

* * * * *

In closing, I want to note that our biggest undeveloped oil resources "prize" will be from applying advanced EOR technology to our undeveloped domestic oil resources.

In the preceding paragraph we set forth the oil production that would be realized from heavy oil and oil sands (up to 0.5 million barrels per day in 2015 and 1 million barrels per day in 2025). Pursuing the rest of undeveloped domestic oil (the light oil left behind after conventional oil recovery) with CO2-EOR would add an additional 1.5 million barrels per day by 2015 and 2.5 million barrels per day in 2025. (These projections of future domestic oil production assume that the recommend actions set forth in response to Questions 5, 6 and 7 are successfully implemented.)

Together, these undeveloped resources could make a most significant reduction in our future levels of oil imports and a most valuable addition to our economic and energy security.

Mr. GIBBONS. Thank you very much, Mr. Godec.

We turn now to Mr. Jack Savage, President and CEO, Oil-Tech, Incorporated. Mr. Savage, welcome here. We look forward to your testimony.

STATEMENT OF JACK SAVAGE, PRESIDENT AND CEO, OIL-TECH, INC.

Mr. SAVAGE. Thank you, and good morning, Mr. Chairman and distinguished members of the Committee. My name is Jack Savage. I am chief executive officer of a small, startup company in Utah, Oil-Tech, Incorporated. I am pleased to have been asked to participate in this hearing and discuss this very important natural resource—resources—of oil shale and oil sands.

You know, there is much negativity associated with failures of the past, when companies back in the '70s and '80s attempted to commercialize shale oil. I think that when we talk about failure, sometimes we can refer to that as "succ-ailure." We appreciate very much the pioneer companies who have gone before and who identified the problems that prevented them from commercializing shale oil. And it must be said that everyone who tried to make oil from oil shale was successful; they just didn't do it economically.

We have been able to take those identified problems, and solve them one by one. So we are grateful for those who went before. May I be so bold as to suggest that if "Black Sunday" had not occurred, if industry had continued to pursue the commercialization of shale oil, this Nation might possibly not be in the foreign-oil-dependent situation that we're in today.

We began in 1993, as a predecessor to the current Oil-Tech company, to work on these identified problems and solve them one by one. I must emphasize that Oil-Tech is complete with the research and development aspect of our project. We are prepared and ready to enter into a commercial venture to produce economically shale oil for commercial use.

I would also say that in doing so, Oil-Tech has never requested—neither have we received—one dime from either state or Federal

Governments. The funding for Oil-Tech has been handled completely by qualified, high-net-worth individuals.

The oil shale deposit that has been referred to this morning is contained on about 5-1/2 million acres. And this tract of oil shale ground is located in the areas comprised of southern Wyoming, eastern Utah, and western Colorado. It is estimated, as has been said, that there is in excess of 3 trillion tons of oil shale in that area, from which it is estimated somewhere between 2 to 3 trillion barrels of oil could be recovered.

This land that we refer to is—approximately 80 percent of it is owned by the Federal Government. The next largest landowner would be state governments; and the Indian tribes own some of the ground; and then there's some privately owned ground.

The technology that Oil-Tech has, and which I will present, has been independently validated by two reputable engineering firms—one out of Billings, Montana; one out of Tulsa, Oklahoma. Those validations concern our representations of process efficiency, cost-per-barrel, and feasibility of up-sizing from a small commercial retort now in operation to a full-size, large commercial retort.

Our current, small-capacity retort and operation in eastern Utah is full-sized on the vertical scale, compared to a full producing commercial retort unit. This is not a laboratory model. We felt we had to build a full-sized scale model to validate the process and the feasibility and the economies of producing oil from shale. All we would need to do would be to increase the footprint, or the diameter size of the retort, to allow more rock capacity to cook in the retort at a given time.

The retort is modular by design. It can be assembled and dismantled very quickly, and moved just as easily as a drilling rig in conventional oil processing could be implemented and removed.

The cost of our 1,000-barrel-per-day retort is indirect—is relative to the cost of drilling a well in the Rocky Mountain area, and equipping the same with the proper equipment.

A 1,000-barrel-per-day retort design was chosen by us as the most feasible relative to capital cost requirements and productivity. If we want to produce 20,000 barrels of oil per day, we simply cluster 20 1,000-barrel-per-day units. And as I said, they are very mobile and they can be moved from one area to another area within a week's time, when a particular area might be mined out. This is a mining material-handling problem. And the build-out of surface retorts would be done so in conjunction with the build-out of an underground mine situation.

I see my time is up, and I will just conclude here quickly by saying that we use very little energy in producing the potential energy of the shale oil. One thing that I learned as a young boy, that when trying to absorb teachings it was much easier to do so when there was a visual aide present. And I have made an assumption that you can also learn more quickly by looking at a visual aide, rather than listening to me. And I've made available these little display units which, hopefully, you'll display on your desk.

There's a piece of oil shale. A lot of people don't know what oil shale is. And then the little vials represent the different stages of the shale through the process; and then the different products that are created thereby.

I would just end by inviting each of you, individually or together as a committee, to come to Utah and visit our site and let us—bring your canteens; we'll fill them with shale oil. And we'd be happy to host you. Thank you very much for your time.

[The prepared statement of Mr. Savage follows:]

Statement of Jack S. Savage, President, Oil-Tech, Inc.

OIL-TECH: THE COMPANY

Oil-Tech, Inc. was incorporated in the State of Utah in February 2000. Oil-Tech (OT/the Company) is current in meeting all state regulations and requirements and is considered a corporation of good standing. OT is a nonoperating company which has just completed its research and development project, has received independent validation of its representations as to its ability to produce oil from oil shale, cost per barrel, feasibility of up sizing to full commercial scale, efficiency of process, etc. Patents have been filed with the U.S. Patent Office, the Patent Cooperation Treaty (PCT) and the country of Jordan.

OT is a privately held Utah corporation formed exclusively to complete the research and development and refinement of patent pending technology which has its roots back to the year 1993. OT's intended purpose is to be an operating entity for the mining of oil shale and the production of shale oil on leased oil shale acreage currently held by the Company in order to capitalize on the Company's patent pending shale oil production technology.

MARKET SUPPLY AND DEMAND

According to the World Energy Council, the largest oil shale reserves occur in the United States in an area of 5.5 million acres covering northeastern Utah, northwestern Colorado and southern Wyoming. It is estimated that this area contains approximately 3.3 trillion tons, or two-thirds of the worlds's potentially recoverable oil shale resource. This same resource is estimated to be capable of producing more than 2.5 trillion barrels of recoverable shale oil. These reserves contain potential oil supplies that would completely meet the United States' energy demands for the next several hundred years.

The oil demand in the United States is approximately 20 million barrels per day with a major portion of all consumption, both crude and finished product, currently imported at a cost of over $150 billion per year, amounting to the largest single element of the United States trade deficit.

United States crude oil production capacity is estimated at 5.5 million barrels per day (mbd) from approximately 533,000 oil wells, averaging less than 12 barrels per well per day.

OIL-TECH ADVANTAGES

To the best of the Company's knowledge, no other entity has a technological or economic advantage or has developed oil shale technology to the level that Oil-Tech has reached. Dr. Anton Damer of the Department of Energy believes OT to be 10 years ahead of any other company engaged in the commercialization of shale oil. Dr. James Bunger, consultant to the Department of Energy on oil shale matters believes OT to be the leader in surface oil shale retort technology.

OIL-TECH'S TECHNOLOGY AND ASSOCIATED PROCESSES

The Company currently operates a small capacity, commercial retort in eastern Utah, approximately 40 miles southeast of Vernal, Utah. The retort has a capacity to process one ton of oil shale per hour. On average, one ton of oil shale will produce one barrel of shale oil. The proprietary retort produces 30 degree API gravity oil with a pour point of 53 degrees Fahrenheit. When the nitrogen compounds are removed from the shale oil, the resulting product is very close to JP-8 fuel. The refinery ready crude is comprised of approximately 10% Naphtha, 40% Kerosene, 40% diesel and 10% heavy residual gas oil. The entire blend is low in sulfur.

The Company's existing, small capacity commercial retort was designed and fabricated to be full scale vertically. Full, commercial size on the vertical scale is essential to enable sufficient "soaking" time of the oil shale in the retort produced heat. A less than full size laboratory model would be insufficient to prove the methodology of OT's proprietary technology. To move to a full capacity (1,000 barrel per day) commercial retort, increasing the size of the "foot print" and adding additional heaters is all that remains. Up sizing to the full commercial scale of 1,000 barrels per day with anticipation of equal or enhanced results of the current operating model

has been validated by the independent engineering firms of Unifield Engineering, Billings, Montana, and Tulsa Combustion, LC, of Tulsa, Oklahoma.

The proprietary retort is modular by design. One full capacity commercial retort can be assembled and/or disassembled as quickly and easily as a standard drilling rig. Accordingly, it is easy and cost efficient to move these portable retorts when an area of oil shale has been mined out.

The 1,000 barrel per day capacity retort was designed as such to be economical in the fabrication process (approximately $2 million for each retort), to be portable and any number of retorts can be mass manufactured and clustered together to, in combination, process the daily tonnage capacity of any given mine. For example, if the desired oil production is 20,000 barrels per day, 20 1,000 barrel per day retorts will be clustered together to reach the desired production rate. Additionally, if one retort is shut down for repair or service, 19,000 barrels of oil are still being produced. Conversely, with a single, highly capital intensive 10,000 barrel per day retort, if shut down for service or repair, the loss of oil production is much more significant.

Contrary to some oil shale processes, the Company's proprietary technology utilizes very little purchased energy to manufacture shale oil. Initially, the oil shale is heated electrically. After approximately 6 hours of operation, there is sufficient "spent" shale to enable co-generation. The spent shale exits the retort at approximately 1,000 degrees Fahrenheit. Fixed carbon remains in the spent shale and is combustible with the addition of air. The temperature of the spent shale is then raised to approximately 2,500 degrees Fahrenheit. This is a sufficient heat source to enable purchased electrical power to be turned off and new oil shale to be adequately heated with direct heat from the spent shale. Every 60 minutes approximately 41 tons of 2,500 degree spent shale is produced. This is an impressive thermal mass, to say the least. Heat is available for generating steam, heating refinery feeds, generating electricity, etc.

Per barrel of oil production/retorting cost is $8.00 per barrel when utilizing purchased electrical heat and decreases dramatically to $4.00 per barrel when using co-generated heat. This per barrel of oil cost considers only the retorting costs and does not consider the mining costs. Mining costs range from $5.60 per ton of oil shale mined to $22.00 per ton depending on the development stage of the mine and the type of equipment utilized. Accordingly, OT's technology and processes can produce one barrel of shale oil at approximately $9.60 per barrel in the best case scenario and approximately $30.00 per barrel in the worst case scenario.

The Oil-Tech technology is environmentally friendly. The retort is an oxygen free, sealed unit under vacuum. No gases are deployed to the atmosphere. In fact, the only non-condensed gas produced is propane. This gas is captured, processed and is then marketable. OT would be the most environmentally friendly operation in the eastern Utah oil shale area which is already dotted with oil and gas wells, transportation pipes on the earth's surface, open, mined out, abandoned gilsonite veins, abandoned structures, etc.

DISPELLING THE MYTHS

For many years, individuals and companies have wrestled with producing oil from oil shale. Along with this knowledge, several myths evolved explaining why the production of oil from shale is seemingly "impossible." These myths can be found through any Internet search. Previous efforts have significantly assisted Oil-Tech in attempting to overcome earlier identified problems. These out-of-date "facts" are dispelled by the Oil-Tech technology and development plans.

There is oil in oil shale...UNTRUE—there is no oil in oil shale, only organic material. The Oil-Tech process vaporizes this organic material and condenses this vapor into shale oil.

The process requires huge volumes of water...UNTRUE—past efforts used water to transport a shale oil "slush" through pipelines to a central processing center. The Oil-Tech technology processes oil shale on site and does not require water in the process. There is a nitrogen compound removal on site to separate the refinery feedstock from the asphalt additive, and water is not required in this process. Water is required for personnel and safety use (showers, potable water, fire suppression), and for mining operations, most of which is recyclable.

The oil shale mining costs are excessive...UNTRUE—mining is indeed required. In the last 15 years, the technology of mining has dramatically changed and the cost of large scale mining operations has dropped from $20 to $25 per ton of material produced, to as low as $6 per ton, depending on depth of the mining operation. The longwall and continuous mining technologies are key to these better economics. The technologies were not available during the last period of heavy research and the attempted production of oil from oil shale.

Mining is environmentally disastrous...UNTRUE—with longwall and continuous mining technologies, very little evidence of the operation exists above ground and the techniques allow for an easy and acceptable reclamation of the surface when operations are complete.

The technology of producing oil from oil shale is highly polluting...UNTRUE—the Oil-Tech process is completely contained, with no harmful emissions to the atmosphere. All products from the process are utilized within the sealed system. Even the leftover spent shale has the qualities of desiccated charcoal which is used in many ways to absorb pollutants.

It is not economically feasible to produce oil from shale because of the capital required...UNTRUE—early attempts by other required heavy capital expenditures on huge facilities based on the alleged benefits of economies of scale. The Oil-Tech process reverses that trend and uses smaller, easily replicated and fabricated modular units. These may be easily transported and assembled on site, or disassembled for movement to another location. Any operational/service problems do not disrupt production by more than a minimal percentage.

It is not economically feasible to produce oil from shale because of the energy required...UNTRUE—the Oil-Tech process has been validated to produce shale oil with a very low energy cost. The system can also be upgraded by utilizing co-generation and a variety of BTU recovery technologies that virtually eliminate the need for external power for any site operations.

Transportation of the product is prohibitively expensive...UNTRUE—this statement is based on the idea piping shale oil sludge to various processing centers, involving pipelines, pumping facilities and rights-of-way disputes. It also was based on shipping raw shale oil to potential refining centers for pre-processing prior to normal refinery operation. The Oil-Tech process does not need to transport shale sludge or raw shale oil to a refinery based pre-processing center. Refinery grade feedstock is either transported in tanker trucks or injected into a local pipeline. The asphalt additive is easily transported with heated tanker trucks. On sites where the nitrogen extraction process will not be available, the shale oil is easily transported in tanker trucks.

OIL-TECH HAS COMPLETED R & D

It is important to understand that the Oil-Tech technology has met the standards of independent validating engineering firms and is now poised to begin commercialization of shale oil. From the point of receiving required capital investment, Oil-Tech can be producing 1,000 barrels of shale oil within 12 months. Production will be at 20,000 barrels of shale oil per day at the end of a 36 month period.

INVITATION

Oil-Tech invites any and all U.S. Congressmen/Congresswomen to visit the proprietary retort site near Vernal, Utah, and experience first hand the economical production of shale oil from our nation's vast supply of natural resource.

Mr. GIBBONS. Thank you very much, Mr. Savage. And I am sure that these little display items will generate a couple of questions for you later on. But we appreciate it, and it does help us immensely to have the visual aide before us.

We turn now to Mr. Terry O'Connor, Vice President, External and Regulatory Affairs, Shell Unconventional Resources Energy. Mr. O'Connor, welcome. The floor is yours. We look forward to your testimony.

STATEMENT OF TERRY O'CONNOR, VICE PRESIDENT, EXTERNAL AND REGULATORY AFFAIRS, SHELL UNCONVENTIONAL RESOURCES ENERGY

Mr. O'CONNOR. Good morning, Mr. Chairman and members of the Committee. I'm delighted to be here today to describe to you Shell's initiative to develop and advance—hopefully, to commercial success—a unique and innovative technology which we are increasingly optimistic can open up the vast oil shale resources of the Green River Basin of northwestern Colorado, eastern Utah, and southwestern Wyoming; which, as you have heard, contains an

extraordinarily large quantity of potentially recoverable fossil fuels, both oil and gas.

People talk about does it have a trillion, or 1.6 trillion, or how much does it have. We don't know how much is out there, because it really depends upon the technological advances that occur over the coming years and decades. But we are quite aware that, when looked upon a global standpoint, roughly two-thirds of all of the oil shale located in the world today is located in this Green River Basin.

And it roughly equates to all—if it's roughly a trillion barrels, which is a report that the Department of Energy put out last year on the strategic importance of oil shale, may very well represent at least as much as all the discovered and proven conventional oil resources in the world today.

This Shell technology, which we call the "In-Situ Conversion Process," or ICP as an acronym, we believe that once proven thoroughly through a next stage of development, should allow Shell to produce clean transportation fuels of gasoline, jet fuel, and diesel, as well as very environmentally clean natural gas, in an economically viable and environmentally sensitive manner.

Let's talk a little bit about where we've been and where we're going for a moment. Some 23 years ago, in 1982—literally in the shadows of the unsuccessful efforts to develop oil shale in western Colorado and eastern Utah—Shell commenced laboratory work in its laboratories in Houston to determine whether this in-situ conversion process technology may have merit. We continued with this lab research for 14 years and, in 1996, successfully carried out our first, very small-scale field experiment in Rio Blanco County, which is located about 200 miles west of Denver.

Shell has now successfully completed four more increasingly complex, but still rather small, integrated projects; the last of which I'd like to just take a few moments to talk about a little bit today, because we're rather excited about the results.

We successfully produced about 1,400 barrels of oil and associated gas from a very small site that's probably half the size of this hearing room today, Mr. Chairman. And we were really excited about this; not only because we were able to produce this quantity of very light end oil and associated natural gas from such a small site, but we were able to produce it almost in perfect harmony with our expected modeling from a time, from a volume, and from a quality standpoint. This gives us sufficient confidence to move to what we hope will be our final oil shale test before hopefully making a decision by the end of this decade.

With regard to the technology itself, literally, what we are doing is sort of the converse of what the retort technologies attempt; in that we take the heat to the rock, rather than bringing the rock to the heat.

What does this mean? Well, literally, what it means is we drill quite a number of vertical holes—not very large; about the size of a softball—vertically down into the oil shale; and we drop down electric heaters; and we slowly heat that sub-surface resource over a period of two, three, or four years, up to the point when the resource itself reaches about 650 or 700 degrees, at which time

we're then able to recover the light end portion of this oil, as well as gas.

And we recover about two-thirds light end oil, and about one-third gas. We recover it in extraordinarily high volumes. We currently estimate that with this technology we'll be able to recover somewhere in excess of a million barrels of product per acre, or somewhere approximately 1 billion barrels per square mile.

Talking just for a moment about the environmental impacts of this—because this is something we're extraordinarily proud of and we're happy to talk about potential environmental effects—because the ICP process involves no mining, and thus creates no contaminated tailings, piles, or large waste disposal issues, our footprint is considerably smaller.

It's easier to reclaim, from a surface standpoint. We use a lot less water. And as I indicated before, we're thus able to penetrate depths which other technologies may not be able to penetrate, and thicknesses. Some of those thicknesses of oil shale in the Piceance Basin of Colorado are in excess of 1,000-foot thick. That's ideally suited for our type of technology, and that is a large part of the reason why we're able to get these extraordinarily large recoveries. It creates a smaller footprint because we're able to go into these thicker, deeper seams.

And one of the issues from an environmental standpoint about which we are most proud is that we have developed a very robust system for protecting the ground water. This sounds a bit counter-intuitive, but before we heat the area that we are attempting to develop, we literally build an ice wall around the circumference of the area. Ice creates an impermeable substance, and we're able thus to be able to contain the area of impact. That results in the prevention of offsite ground water impacts, and allows for much more efficient and expeditious ground water clean-up after the process is completed.

Moving on, I think it's relevant to point out that, while the United States—and particularly, the Green River Basin of Colorado, Utah, and Wyoming—are really the Saudi Arabia of oil shale, oil shale is nevertheless located in a number of other countries around the world. And in fact, four countries—namely, Estonia, Brazil, China, and Australia—currently have ongoing R&D projects for oil shale, despite the fact that their oil shale resources are not nearly as concentrated, as rich, or as extensive. They're all being done with various degrees of public assistance.

We think that the time has now come for the United States to join these other countries, to advance the technologies and develop commercially oil shale, as long as it can be done in an environmentally sensitive and economically feasible manner.

In the interests of time, I'm not going to go into the specifics of several recommendations that we have submitted in our written testimony, but really would commend them to you for your proactive and favorable consideration.

We do thank this Committee, this Subcommittee, the full Resources Committee, and in fact the House of Representatives, for including the first two of these recommendations in general terms in the energy bill which you passed a couple of months ago.

I would also mention and thank the Bureau of Land Management, Department of Interior, because they just recently took a small but extraordinarily important step of finalizing a small research and development leasing program for oil shale. And they've really done a good job in advancing this as a first step. They need to now continue on toward commercialization in a rational manner.

And I might also add that Secretary Norton today as we speak is at our site, viewing and being briefed on the aspects of our research and technology and where we're attempting to go strategically. And I, too, would invite the members of this Committee, individually or collectively, to come out and look at our ongoing research.

In summary, we believe that the time has come for Congress and this Administration to conduct appropriately targeted legislative and regulatory measures to advance responsible oil shale development in this country. And we're increasingly encouraged that the Shell in-situ conversion process may very well be the first available technology to do so on a commercial basis. Thank you very much.

[The prepared statement of Mr. O'Connor follows:]

Statement of Terry O'Connor, Vice President of External and Regulatory Affairs, Shell Unconventional Resources Energy

Good morning Mr. Chairman and Members of the Energy and Mineral Resources Subcommittee:

My name is Terry O'Connor. I am Vice President of External and Regulatory Affairs for the Shell Unconventional Resources unit of Shell Exploration and Production Company. I am delighted to appear before you today to describe Shell's initiative to develop and advance, hopefully to commercial success, a unique and innovative technology which we are increasingly optimistic can open up the vast oil shale resources in the Western United States. This technology, once thoroughly proven technically, will allow Shell to produce clean transportation fuels such as gasoline, jet fuel and diesel as well as clean burning natural gas from oil shale in an economically viable and very environmentally sensitive fashion. Because the oil shale resource in the United States is extensive, this technology holds promise for significantly increasing U.S. domestic energy production.

For decades, energy companies have been trying, without success, to unlock the large domestic oil shale resources of northwestern Colorado, eastern Utah and southwestern Wyoming. Oil shale can be found in large parts of the Green River Basin and is over 1,000 feet thick in many areas. According to DOE estimates, the Basin contains in excess of 1 trillion recoverable barrels of hydrocarbons locked up in the shale. It is thus easy to see why there have been so many attempts to unlock this potentially enormous resource in the past.

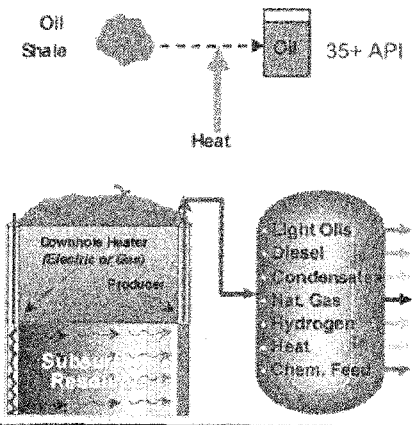
Some 23 years ago, Shell commenced laboratory and field research on a promising in ground conversion and recovery process. This technology is called the In-situ Conversion Process, or ICP. In 1996, Shell successfully carried out its first small field test on its privately owned Mahogany property in Rio Blanco County, Colorado some 200 miles west of Denver. Since then, Shell has carried out four additional related field tests at nearby sites. The most recent test was carried out over the past several months and produced in excess of 1,400 barrels of light oil plus associated gas from a very small test plot using the ICP technology. We are pleased with these results, not only because oil and gas was produced, but also because it was produced in quantity, quality and on schedule as predicted by our computer modeling. With this successful test, Shell is now ready to begin work on the final tests that will be required to prove the technology to the point where there is sufficient certainty so as to make a decision to proceed to commercial development.Most of the petroleum products we consume today are derived from conventional oil fields that produce oil and gas that have been naturally matured in the subsurface by being subjected to heat and pressure over very long periods of time. In general terms, the In-situ Conversion Process (ICP) accelerates this natural process of oil and gas maturation by literally tens of millions of years. This is accomplished by slow sub-surface heating of petroleum source rock containing kerogen, the precursor to oil and gas. This acceleration of natural processes is achieved by drilling holes into the resource,

inserting electric resistance heaters into those heater holes and heating the subsurface to around 650-700F. over a 3 to 4 year period. During this time, very dense oil and gas is expelled from the kerogen and undergoes a series of changes. These changes include the shearing of lighter components from the dense carbon compounds, concentration of available hydrogen into these lighter compounds, and changing of phase of those lighter, more hydrogen rich compounds from liquid to gas. In gaseous phase, these lighter fractions are now far more mobile and can move in the subsurface through existing or induced fractures to conventional producing wells from which they are brought to the surface. The process results in the production of about 65 to 70% of the original "carbon" in place in the subsurface. The carbon that does remain in the sub-surface resembles a char, is extremely hydrogen deficient and, if brought to the surface, would require extensive energy intensive upgrading and saturation with hydrogen. Chart 1 illustrates the ICP process.

Chart 1: The ICP Process

Enhancement of natural maturation of kerogen by slow heating

- Results in:
  - thermal cracking
  - in-situ hydrogenation
  - gas phase recovery
  - high API crude



The ICP process is clearly energy intensive as its driving force is the injection of heat into the subsurface. However, for each unit of energy used to generate power to provide heat for the ICP process, when calculated on a life cycle basis, about 3.5 units of energy are produced and treated for sales to the consumer market. This energy efficiency compares favorably with many conventional heavy oil fields that for decades have used steam injection to help coax more oil out of the reservoir.

The produced hydrocarbon mix is very different from traditional crude oils. It is much lighter and contains almost no heavy ends. Its quality can be controlled by changing the heating time, temperature and pressure in the sub-surface. The production mix generally seen from Colorado oil shale is about two thirds liquids and one-third natural gas and gas liquids such as propane and butane. On the liquid product side, the typical split encountered is about 30% each of a gasoline precursor called naphtha, jet fuel and diesel with the remaining 10% of the barrel being slightly heavier. These fractions can be easily transformed into finished products with significantly reduced processing when compared with traditional crude oils.

Because the ICP process occurs below ground, special care must be taken to keep groundwater away from the process, as its influx would seriously reduce thermal efficiency. Special care must also be taken to keep the products of the process from escaping into groundwater flows. Shell has adapted a long recognized and established mining and construction ice wall technology to isolate the active ICP area and thus accomplish these objectives and to safe guard the environment. For years, freezing of groundwater to form a subsurface ice barrier has been used to isolate areas being tunneled and to reduce natural water flows into mines. Where groundwater intrusion is a problem in the ICP process, the subsurface surrounding the rich oil shale layers is frozen to form a container of sorts, thus preventing the influx of water while at the same time containing the products formed. Shell has successfully tested the freezing technology and determined that the development of a freeze wall

prevents the loss of contaminants from the heated zone. During this same test, Shell was able to demonstrate that traditional subsurface reclamation technologies such as steam stripping, pumping and treating and carbon bed stripping were able to remove contaminants developed in the ICP process from the subsurface to levels sufficient to meet stringent permit requirements. Though freezing the subsurface while simultaneously heating it is clearly a counter-intuitive application of technology, it is a good example of the creativity and unconstrained thinking that necessarily has been a major contributor to solving potentially vexing problems in this complex Research and Development project. A schematic of the basic freezing technology is shown in Chart 2.

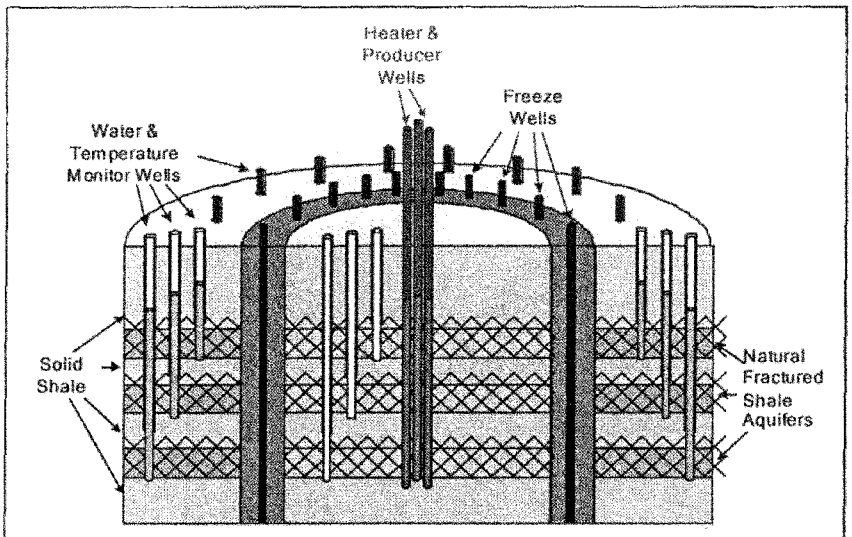


Chart 2: Freezewall Technology

Because the ICP process involves no mining, no large or contaminated tailing piles are created. Water usage is expected to be considerably less than is required for traditional retort methods. Because the technology has the potential to recover in excess of 1 million barrels of oil per acre in the richest parts of the Basin, or about ten times that possible from conventional mining and retorting, temporary land disturbance associated with ICP during production will be significantly less. This smaller and cleaner footprint, the reduced water needs, the reduced processing needs, a robust system for protecting groundwater from contamination and the production of clean, less Green House Gas intensive products creates an environmentally attractive package about which we at Shell are very proud.

It is through well-established technologies and constant monitoring that Shell expects to ensure proper and transparent stewardship of the environment. Shell is already working closely with local communities, NGOs, elected officials, and regulatory agencies to ensure that our research addresses community needs and sensitivities while ensuring strong environmental protection.

Shell is currently focused on reducing the remaining risks and uncertainties that could affect the commercial viability of this technology. For this reason, Shell has a research staff in Colorado of approximately 55 personnel in addition to approximately 100 Houston and Denver based employees assigned to the oil shale project. The focus of these efforts is to insure the technical, commercial and environmental viability of the technology via a relatively large integrated demonstration project. This project would represent the final step required before a financial investment decision would be taken by Shell for a commercial scale unit.

While Shell has spent many tens of millions of dollars on research and development for this technology and has learned a tremendous amount while reducing risk and uncertainty, much work and expenditure still remain before the ICP process can be commercialized. Shell is anxious to proceed with ICP research so as to help unlock the significant potential that oil shale holds to increase indigenous energy

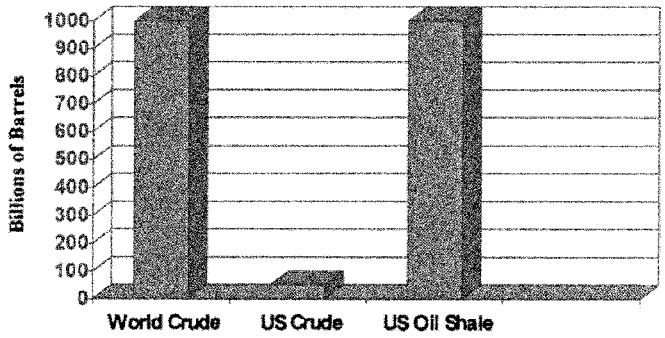
supply in the United States. Achievement of this objective on a timely basis will require the active support of Congress and the Administration

Because the commercial development of oil shale would yield many benefits to the U.S. economy, Shell supports responsible policy initiatives that will facilitate early commercial production of shale oil and associated gas via methods that minimize industry's footprint and protect the environment. Shell is committed to working with Congress, with the Department of Energy, the Department of Defense, the Department of Transportation, the Department of Homeland Security and the Department of Interior, the latter of which has stewardship responsibility over approximately 80% of the oil shale bearing lands in the Green River Basin of the Rocky Mountain West, in order to accomplish this objective.

Key to the early development of oil shale technology is early access to appropriate Federal oil shale deposits to allow for pilot field tests to be carried out. The leasing of tracts of federal land to encourage research and development is an essential next step. As a private company, Shell supports appropriate lease terms and incentives for the development of new oil shale development technologies.

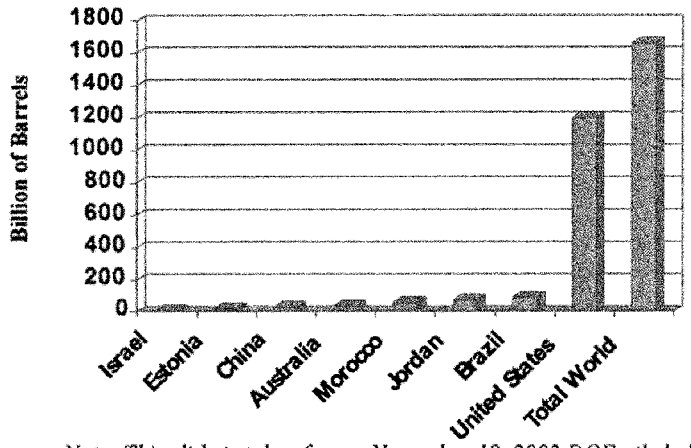
As the Department of Energy has pointed out in a recently released two volume report entitled "Strategic Significance of America's Oil Shale Resource", while oil shale is located in many countries throughout the world, the Green River Basin of northwestern Colorado, eastern Utah, and southwestern Wyoming contains the largest, most concentrated quantities of potentially recoverable shale oil in the world. The Report indicates that the Basin may have as much as 1.6 trillion barrels of oil in place, of which an estimated 1 trillion barrels ultimately may be recoverable using various recovery technologies. This latter number is roughly equivalent to all the combined proven conventional oil reserves in the world today, (see DOE Charts 3, 4 & 5).

Chart 3: World Crude Reserves v. US Oil Shale



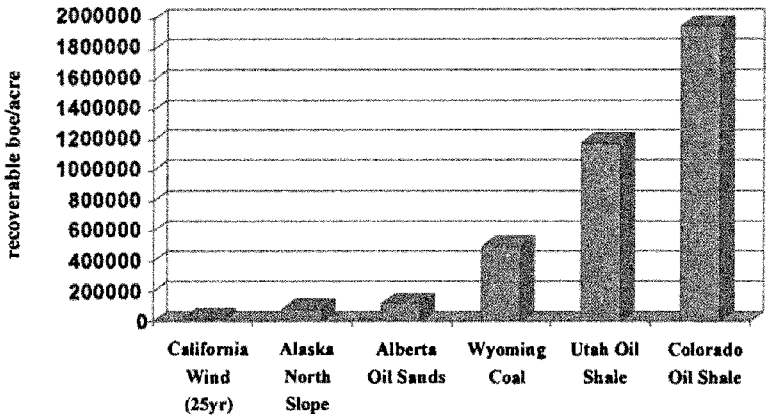
Note: This slide is taken from a November 18, 2003 DOE oil shale briefing

Chart 4: Major World Oil Shale Resources



Note: This slide is taken from a November 18, 2003 DOE oil shale briefing. .

Chart 5: Energy Concentration (bbl/acre)



Note: This slide is taken from a November 18, 2003 DOE oil shale briefing .

Given the size of the resource, Shell is committed to pursuing commercially and environmentally viable technologies that can unlock the enormous potential for oil shale that exists in the Rockies. Shell's advancing ICP research is getting us close to being able to help unlock these resources. We believe that successful utilization of the ICP technology could yield substantial economic impacts to Colorado, the rest of the Rocky Mountain West and to the United States as a whole.

Clearly, Shell believes there is a role for the appropriate development of oil shale deposits as part of America's overall energy and conservation mix to meet increasing energy demand. We are committed to the principles of Sustainable Development, to ensuring that our activities minimize the impact on the environment, and to enhancing opportunities for local communities while facilitating our business objectives.

Ironically, despite the fact that that the United States clearly has the largest and most concentrated oil shale resources in the world, several other countries have ongoing oil shale Research and Development projects. Australia, China, Estonia and Brazil are all progressing projects that are governmentally assisted or driven in one fashion or another. It is Shell's belief that the time has come for the United States to join these other nations so as to encourage, facilitate, and accelerate the development of this potentially vast domestic energy resource.

A range of options should be seriously considered in order to accelerate responsible U.S. oil shale development that would enhance national security and protect our Nation's economy. We would offer the following six recommendations for Congressional consideration. While we are not including specific legislative language, we are eager to work with the House Resources Committee and this Subcommittee, as well as all other relevant House and Senate Committees of jurisdiction on specific language to create the proper mix of incentives and opportunities for accelerated, but responsible, oil shale development.

Recommendations for Congressional consideration of six important provisions:

1. Shell believes that the U.S. government should recognize oil shale as a strategically important domestic energy source. We believe that Congress and the Administration should officially support public policy initiatives that encourage and support accelerated commercial oil shale development and use as a feedstock for transportation fuels and other products.
2. Shell believes that the Secretary of the Interior should develop a commercial oil shale leasing program on an expedited basis. We support the BLM's recently announced R&D oil shale leasing program as an important first step in the right direction. BLM should now be urged to implement that program on an expedited basis.

   Shell thanks the House Resources Committee and this important subcommittee for providing important leadership to the full House of Representatives for including language in the recently passed House Energy Bill that in general terms would adopt these first two recommendations. We hope that legislative opportunities will arise in the future to give favorable consideration to passage of language to address the next four topics.
3. Congress should act to lift the current federal acreage limitation under Title 30, Section 241(a) of the Mineral Lands Leasing Act that restricts a lessee to acquisition of but one lease of 5,120 acres nationally. In order to facilitate commercial development for oil shale production, Shell believes that this acreage limitation should be removed. Otherwise, companies that wish to build facilities and produce shale oil from federal lands will forever be limited to one project. Such a limitation, which dates back to 1920, until changed will create an impediment to even first-generation projects where the costs and risks will be greatest.
4. Congress and the Administration should work to develop royalty rates that encourage investment in oil shale development, giving particular recognition to the extraordinary costs involved in literally bringing a new energy industry into existence. In particular, Shell believes that government should develop a royalty regime for first generation commercial oil shale production that: 1) is simple to administer and to enforce and eliminates the need for interpretation or the likelihood of litigation; 2) would deliver significant revenue to the U.S. Government, and thus 50% of that amount to the impacted states; and 3) would not involve royalty rates that so steep as to create another obstacle to the acceleration of large-scale first generation commercial oil shale projects.
5. Shell believes that Congress and the Administration should work to ensure that an appropriate system is put in place to provide certainty and timeliness in the permitting process for oil shale development without waiving substantive environmental performance standards. A concern is that sequential overlay of multiple federal and state permitting processes has the potential to add many years to what will already be a complex and protracted permitting process.
6. Congress and the Administration should identify appropriate tax incentives that encourage investment in oil shale technology and development, that recognize the research and development hurdles involved in oil shale technology and development, and that appropriately treat oil shale production as the

development of a "non-conventional resource" in a manner similar to other non-conventional energy resources. Specifically, where ambiguities may now exist relative to determining whether or not in-situ oil shale recovery technologies will qualify for tax benefits in the same manner as do existing mining tax regimes, those ambiguities should be cleared up as soon as practicable.

In summary, the United States has a huge domestic energy resource in the form of oil shale. The time has come for Congress and this Administration to consider appropriately targeted legislative and regulatory measures to allow oil shale to be developed at an early date, provided that such development can occur in an economically feasible and environmentally acceptable manner. Shell is increasingly encouraged and optimistic that our ICP technology may very well represent the first available technology to do so.

This completes my written testimony. I will be happy to respond orally or in writing to any questions any Committee member may have.

Response to questions submitted for the record by Terry O'Connor, Vice President of External and Regulatory Affairs, Shell Unconventional Resources Energy

1. Please tell the Subcommittee what you think the primary strengths and weaknesses are with BLM proposed R&D leasing program.

ANSWER: BLM's final R&D leasing program provides an important and timely first-step opportunity to tap a previously undeveloped domestic energy resource and over time hopefully will strengthen America's domestic energy security. Thus BLM should be commended for initiating this important first step. The opportunity exists to "design it right" in terms of developing a regulatory federal access structure that is appropriate for this unique and abundant resource in a manner that minimizes unrestrained "boom and bust" socioeconomic risks and dramatically reduces the likelihood of environmental damage, at the same time as encouraging the advancement of new and innovative technologies to test the extraction of shale oil and gas in a responsible manner.

The advantages of BLM's final R&D leasing program are many, including but not limited to the following examples:

- Establishing a framework for cautious, small scale testing of innovative shale oil and gas recovery technologies on Federal lands.
- Providing first-of-its-kind small scale leasing of tracts up to 160 acres for appropriate shale oil recovery technologies.
- Providing a vitally important mechanism that will grant responsible operators the eventual right to convert the small tract to a larger commercial sized tract upon demonstrating the advancement of commercial production capability, subject to the payment of a conversion fee, NEPA compliance and obtaining necessary state and federal permits.

While BLM's final program does not have major weaknesses, Shell does urge BLM expeditiously to develop and finalize regulations that specify the amount of conversion fees plus the size of commercial royalties, so as to give responsible, potential oil shale developers a degree of economic certainty as to their future obligations to the Federal Government.

2. What does the price of oil need to be for Shell to make an acceptable profit using the ICP process?

ANSWER: Based upon 23 years of laboratory and bench top research plus 9 years of field research and development, Shell believes that it can make an acceptable return in a first generation commercial project with oil prices in the $25-30 per barrel of crude price—-assuming Shell can access appropriate Federal lands, first for a next stage R&D pilot project development and then onto commercial acreage for larger scale operation. This crude price assumption for Shell's ICP technology is not currently applicable to most other Green River Basin oil shale resources. Conversely, once Shell has built and operated a first-of-its-kind commercial facility, we believe that our future learnings should result in recovery cost reductions for subsequent second and third generation project developments by Shell or others.

3. How large does Shell think that individual lease tracts should be?

ANSWER: For initial R&D lease tracts, Shell supports the 160-acre limitation for primary recovery operations, although we may need limited additional surface-only use for ancillary surface support activities. For commercial-scale lease, Shell supports the 5,120-acre lease size. However, it is vitally important that Congress

amend Section 241 of the Mineral Lands Leasing Act to allow responsible operators to acquire more than just one oil shale lease in the United States.

4. What limitations on acreage under lease should apply to each developer, if any?

ANSWER: As noted in the answer to Question 3 above, it is critical that Congress amend Section 241 of the MLLA to allow companies to acquire more than just one oil shale lease nationally. While Shell sees no compelling reason to provide any other arbitrary limits on acreage, we would not object to a 50,000-acre national total, so long as multiple oil shale leases can be secured.

5. What royalty structure would Shell recommend?

ANSWER: Given the unique but yet undeveloped nature of commercial oil shale production, a traditional approach to establishing an oil shale royalty is not feasible or equitable to either side at this time. Unlike other royalty matters that BLM and MMS have faced in the past, oil shale has never been produced in commercial quantities in the United States or elsewhere in the world. Thus there is no currently available royalty benchmark for oil shale. Traditional oil and gas plus coal development each have a long history of operational and marketing practices to establish both a valuation basis (gross value) as well as a rate (8%, 12 1/2%, etc.). Unlike oil and gas, where the development and lifting costs of the product are relatively small, oil shale development on a commercial basis inevitably will involve enormous and speculative financial risk capital as well as very substantial ongoing operational expenses far greater than conventional oil and gas development.

It is thus critical that reasonable parameters be inserted around royalty provisions to avoid onerous regulatory revisions in the future and to assure that a royalty methodology that meets the following criteria is met:

- A royalty that is simple to administer and to enforce and virtually eliminates the need for interpretative litigation,
- A royalty that over time would deliver significant revenue to the U.S. Government (and thus 50% to the impacted state), and
- A royalty that would not be so large as to create another obstacle to the acceleration of large scale U.S. based commercial oil shale projects.

As a result the following royalty mechanism is recommended for the initial 20-year primary term of a commercial oil shale lease:

Each year the royalty should be set by the Secretary at 5% of the average West Texas Intermediate crude price (or a similar generally recognized crude price, should the WTI be discontinued in the future) from the average of the price during the last month of the preceding year. At the 20th anniversary of the lease, the royalty may be readjusted based upon then applicable rules promulgated by the Secretary.

The calculation of royalty due and owing shall be established on a royalty of net oil and hydrocarbon gas in barrels of oil equivalents produced and sold or removed from the leased premises if no offsite processing or upgrading occurs, or from the final point of processing or upgrading, less power fuel used in the production and upgrading operations, said value to be measured in barrels for imported liquid energy sources imported to the operations, and in barrels of oil equivalents from the gaseous, solid or electrical energy imported to the lease or upgrading site.

A net royalty is needed to allow on-lease use of produced energy in the recovery process. Furthermore, an offset for purchased power fuel should be credited given the energy intensive nature of new evolving in-situ technologies that have the capability of recovering up to 10 times more oil and gas per acre than did traditional retort technologies but that will require the substantial import of power to stimulate such production. Imported power will likely represent the largest cost component for in situ development. Thus the above-recommended provision should provide maximum flexibility to use any primary energy source.

6. What are the most important actions for the Federal Government to take in order to ensure development of a large and vibrant oil shale production in this country?

ANSWER: As reflected in more detail in Shell's written testimony, we believe that the following Congressional actions should be initiated to facilitate responsible and orderly but expedited advancement of shale oil recovery technologies:

a. The U.S. Government should officially recognize oil shale as a strategically important domestic energy fuel source.
b. The Secretary of Interior should be directed to promptly develop and implement a commercial oil shale leasing program.
c. Congress should lift the current federal acreage limitation (as noted in Answers to Questions 3 and 4 above).

d. The Secretary should be directed to establish reasonable, balanced and simple royalty rates for commercial oil shale development, as described in more detail in Answer to Question 5 above.
e. Congress and the Administration should work together to ensure that an appropriate system is put in place to provide certainly and timeliness in the permitting process without waiving substantive environmental standards.
f. Statutory appointment of an in-situ oil shale permitting focal point to expedite all state and federal NEPA compliance and permitting efforts should be considered. Such a position should have adequate authority and resource to streamline the process and avoid frivolous delays without waiving substantive environmental standards.
g. Congress should identify appropriate tax incentives to encourage investment in oil shale technology and development, similar to those now or previously provided for other non-conventional resources, such as the percentage depletion allowance and Section 29 production tax credits.

7. From an industry perspective, what would you suggest that the Government can and should do to convince industry that Government is willing to be a long-term, reliable partner in mitigating the risks of establishing a new industry in oil shale?

ANSWER: A good first step has been the Government's recognition of the opportunity and its subsequent offering of the R&D leasing program by the BLM. Industry will respond to governmental efforts to facilitate and reward pioneers that have taken the R&D risk and incurred the risk capital to provide new technology, provided that the oil shale R&D technology is conducted in an environmentally responsible and economically feasible manner. Industry will need the U.S. Government to facilitate a timely regulatory and permitting process to avoid undue obstacles to project approvals that can and will undermine the economic viability of capital intensive, first-of-its-kind projects, and that royalties generated are properly allocated to the benefit of those impacted most by oil shale development.

In addition, the potential role of the Department of Defense should not be overlooked. As the single largest user of transportation fuels and a key branch of Government with responsibilities for domestic security, the potential availability of an additional domestic source of clean transportation fuels would seem to be a good fit as the DOD moves toward its single battlefield fuel of the future strategy in the next decade. Thus appropriately structured commercial transactions may be an attractive win-win option for both industry and DOD.

8. Do you agree with the perspective that we will need both in-situ and surface processing facilities to make optimal use of domestic oil shale resources?

ANSWER: Although Shell has chosen to pursue exclusively the in situ development route, we believe that different recovery processes ultimately may be appropriate for different depths, thicknesses, and qualities of oil shale resources; thus different aspects of the oil shale industry will likely involve both forms of recovery. The financial strength of operators will be also be a major factor, as few companies can garner the capital resources needed to develop a large-scale oil shale operation.

9. If government were to assist at the R and D phase where do you see the need and role of government-supported research and development?

ANSWER: In addition to the vitally important aspect of providing small sites upon which to conduct R&D testing (through the recently announced R&D leasing program by BLM), there is also an important role for the Government laboratories in joint research on a variety of technical, engineering and environmental matters (such as carbon sequestration).

10. You are out in front of this in Colorado, and have an industry perspective on the planning and impact mitigation process. How should government manage requirements for front-end costs to assure that adequate and timely revenues are available to communities and are fair and attractive to industry at the same time?

ANSWER: This is an insightful question that Shell has also been considering to avoid/mitigate the various types and extents of social and community impacts that occurred in Colorado in the late 1970s and early 1980s. A large-scale commercial oil shale operation will have a significant impact on any nearby communities, the extent of which depends on the existing infrastructures and many other factors. Such development will require prudent social investments on the part of the operator, as well as the local, state and Federal governments to provide community development resources, which will be defrayed by severance tax and royalty generation. The extent of these needs will be identified in the Social Impact Assessment process, stakeholder engagement sessions, and other forums of public input, and it

will be important for the governments, communities and industry to work together to provide a sustainable development process.

Mr. GIBBONS. Thank you very much, Mr. O'Connor. We appreciate your presence here today and your testimony is very helpful to us.

We turn now to Mr. Greg Stringham, Vice President, Markets and Fiscal Policy, from the Canadian Association of Petroleum Producers. And Mr. Stringham, I notice that you have Mr. Murray Smith back in the audience. I'm very much aware of Mr. Smith's history, his background in Canadian efforts there.

We do know that Alberta is now one of the major producers of oil for the United States, from its oil sand. So if you would like to have Mr. Smith join you at the table, please let me invite Mr. Smith up to join you for your testimony.

Mr. STRINGHAM. Thank you. That would be great. I will have Mr. Smith speak just following my comments, if that's OK with you.

Mr. GIBBONS. Absolutely. Please.

Mr. STRINGHAM. Thank you, Mr. Chairman.

Mr. GIBBONS. The floor is yours. We look forward to your testimony.

STATEMENT OF GREG STRINGHAM, VICE PRESIDENT, MARKETS AND FISCAL POLICY, CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

Mr. STRINGHAM. Thank you. It's a pleasure for us to appear before you, Mr. Chairman, and Committee members. It's not very often that Canada takes the opportunity to be able to appear before these committees; but we thought that today, given our experience in oil sands, recognizing it is somewhat different than the oil shales and tar sands that you have in the United States, it would be useful for us to be able to share our experience with you, to be able to see if there are some learnings there that may be useful.

As you mentioned, Mr. Chairman, the oil sands that we have in Canada are in full development. It was unconventional at one point in time. And as you said in your opening remarks, it is not unconventional any more. It is certainly being produced at a rate of 1 million barrels per day, coming out of the oil sands. And from Canada, that represents one out of every two barrels of oil that we produce. And as you know, we export well over half of our production to the United States at this point in time. So it is a very valuable resource.

We look forward, as the projects have been announced, to having close to 3 million barrels a day coming out of the oil sands in just ten years time. So there is a very strong growth that's happening in the oil sands, and that will then mean that three out of every four barrels of oil produced in Canada will be coming from the heavy oil and oil sands resource. So it has now become a very conventional and a very important resource.

It does also have in there—and we will use a number of numbers—but 174 billion barrels of established reserves. You mentioned in your opening comments the 1.7 trillion barrels in place, but we know that we can get at, with today's technology and economics, over 174 billion barrels. Now, that's a big number. To put

it in context, that's well over 200 years' worth of production at today's levels of projected production going forward. Very large number.

One of the things that I learned as a young engineer coming out of university, I began working in research in the oil sands, and that was over 20 years ago, and there were already a handful of commercial projects underway. This is not a short-term research project that will provide instant results.

But what has happened in Canada is there has been a long-term effort of research and development and incremental improvements over time, similar to the projects you've heard from these other gentlemen, that have unlocked the key to the development of this key resource in Canada.

One of the things that was really critical was the reduction in cost estimates. And in the information that I have provided to you, the supply costs for the development of the oil sands in Canada for the heavy oil, which is very much—bitumen is the name of it. It's tar-like. You have a sample of it, I think, you've seen; almost molasses-like material. The cost of development, including capital costs, operating costs, royalties, taxes, and the return to the investor, is somewhere in the range of $8 to $15 a barrel U.S.

If you upgrade it into the light sweet crude, which has no bottoms and then can fit right into a refinery very, very nicely, the cost of that is somewhere in the range of $18 to $23 a barrel—all in supply costs; not just operating costs. So you can see that it becomes very economic to develop this resource.

I would like to point out the key differences that we see between the oil sands in Canada and the tar sands or oil shale. As you may or may not know, the oil sands in Canada has been blessed by its formation with a water layer that surrounds it. So you have a sand molecule that's surrounded by a water layer; and then the oil, or the heavy oil, sits on the outside of that.

And so the separate process is somewhat different, and perhaps a little easier, than the oil shale. It's a lot like salad dressing. If you shake it up and mix it with water, the oil will float to the top, the sand to the bottom, and the water stay in the middle. And that's essentially the process. It can be done at about 60 to 70 degrees Fahrenheit, and doesn't require the extensive energy that's used in other processes. Whereas the oil shales and tar sands, as I understand that you have in the U.S., has the sand molecule with oil just locked right on top of it, and requires these additional processes.

One of the things that I could pass on as one of the key elements of success that we have seen in Canada in the development of the oil sands has been a very strong cooperative relationship between industry and government on the research. And I'm not now just talking bench-scale and lab-scale research. What was a really key unlocking feature that happened early on, and again back in the 1990s, was cooperation between the government and a variety—a consortium of industry players, that developed technology that, when it then became successful, was immediately dispersed throughout the industry, because everyone had access to it. So there's a two-pronged approach: the consortia, dispersion of

technology; as well as the individual projects like Shell and Oil-Tech and others that are doing right now.

To give you an idea of investment that's being put into this, at a commercial level now, we are investing this year $7 billion into the oil sands in Canada. Over the next five years alone, we will invest another $36 billion U.S. in the development of these projects. And these projects will then, as I said, turn around and produce close to 3 million barrels a day over that ten- to 12-year period.

I've brought with me today a summary that's put together by our National Energy Board, your equivalent to the FERC here in the United States. They have done a historical, technological, research, and market analysis of the oil sands in Canada that gives you an outline of the technologies used, how the research was developed. And I will leave that here with the clerk for your information. I won't go into the detail here. But it is a very good summary document to provide the background for you.

And last, I must mention that as we look forward in the oil sands development in Canada, we do recognize that the United States is a key and our primary market—a very good customer. The reason that we are here today is because we would like to share that experience, learn mutually; but also, to get you to recognize that as we develop this new oil sand, it will require new markets, including new changes to refineries, modifications and building of refineries, to be able to handle the oil that we expect to come out of Canada, as it moves into the growing market of North America.

Thank you very much. Let me turn some time over to Mr. Smith, if that's OK, Mr. Chairman.

[The prepared statement of Mr. Stringham follows:]

Statement of Greg Stringham, Vice President, Markets & Fiscal Policy, Canadian Association of Petroleum Producers

Overview of Canadian oil sands development and technology

The Canadian Association of Petroleum Producers appreciates the opportunity to submit this overview of the Canadian experience in oil sands development to the House Energy and Mineral Resources sub-committee.

While the issue that this committee is addressing has multiple aspects with much more detail than provided here, CAPP believes that many of the experiences, technologies, policies and research processes used in Canada to develop its oil sands resources would be beneficial to the committee on this subject.

The oil sands in Canada are a vast resource. From early discovery and use in the 1800's to first commercial production attempts in the early 1900's, and government directed pilot tests in the 1920's and again post WWII, they moved into early commercial production with the Great Canadian Oil Sands (now Suncor) in 1967. Technology has been the key to unlocking this resource and production now exceeds 1 million barrels per day. Forecasts see this growing rapidly to over 2.7 million barrels per day in the next 10 years.

While oil sands are significantly different from oil shale the government and industry research and development process could provide valuable and potentially transferable insights for oil shales.

The main difference between oil sands and oil shale is that the oil sands are particles of sand, surrounded by a microscopic layer of water that is then in turn surrounded by the heavy bitumen (thick oil), as shown in the diagram at the end of this submission. Separating the oil from the oil sands is much easier because of this water layer, since the oil is "suspended" in the water/sand layer not directly stuck on the sand.

In oil shales, this layer of water is not there and the oil is stuck directly onto the rock making it much more difficult to separate the oil from the rock (shale).

The key to unlocking the vast potential of the Alberta oil sands has been sustained and cooperative industry and government research and development. This includes research efforts under the Alberta Research Council, the Alberta Oil Sands

Technology and Research Authority, the Canadian Oilsands Network for Research and Development and more recently the Alberta Chamber of Resources' Oil Sands Technology Roadmap and the research coordination of the Alberta Energy Research Institute.

The attached set of charts and pictures outlines the oil sands resource in Canada, the history and the technologies that have been key to unlocking this vast resource. The real key to the development has been a long and dedicated research and development program that has yielded technologies and advancements that have reduced costs and provided economic access to the oil contained in this resource.

In addition Canada's federal regulatory agency, the National Energy Board (NEB), has published two Energy Market Assessment reports on Canada's oil sands that provide detailed information on the Canada's oil sands resource, technology, research, supply costs, production, pipelines and markets. They are available from the NEB at www.neb.gc.ca under Publications, Oil Sands

CAPP would be pleased to respond to any questions the committee may have regarding the Canadian oil sands and we would be pleased to do this either in writing or when we will be in Washington at the end of June 2005. Please direct any questions to:

NOTE: Attachments to Mr. Stringham's statement have been retained in the Committee's official files.

Response to questions submitted for the record by Greg L. Stringham, Vice President, Markets & Fiscal Policy, Canadian Association of Petroleum Producers

Question 1: Alberta's oil sands production is often likened to U.S. oil shale production potential. The similarities with U.S. oil shale cannot be dismissed. Please tell us how your industry engaged and cooperated with the various government and private citizen stakeholders to create the mammoth producing capability you have today.

The key to unlocking the vast potential of the Alberta oil sands has been sustained and cooperative industry and government research and development. This includes research efforts under the Alberta Research Council, the Alberta Oil Sands Technology and Research Authority, the Canadian Oilsands Network for Research and Development and more recently the Alberta Chamber of Resources' Oil Sands Technology Roadmap and the research coordination of the Alberta Energy Research Institute.

Stakeholder consultation and input is sought out. There is an extensive pre-application consultation process for sharing information as well as raising and addressing stakeholder concerns. In addition the regulatory process addresses the technical, environment and socio-economic aspects of these projects and provides an avenue for affected stakeholder issues to be addressed.

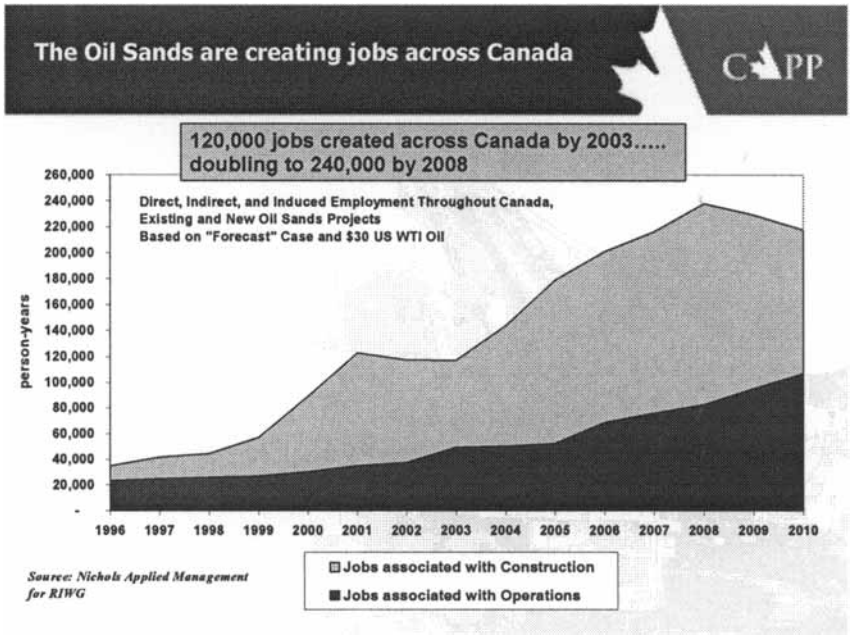
In Canadian oil sands development, there is a balance of roles between government and industry. The resource is owned by the province, which leases the resource to industry to develop and in return receive a royalty payment (described below). In addition, governments provide policy foundation and the public infrastructure necessary to enable the developments and the private sector provides the investment and expertise to construct, operate and reclaim the project. This combination results in environmentally sensitive development, job and business creation, royalty and tax revenues to governments and earnings to the private investors.

Question 2: What problems does your industry face as it continues its exponential growth?

The Canadian oil sands are set to increase from its current 1 million barrel per day level to 2.7 million barrels per day in the next 10 years. This is one of the only areas in the world with the potential to increase production on this scale. But it is not instantaneous nor without challenges. While the historical challenges of technology and economics have been overcome, we are still working on new technologies and continuing to lower costs. The main issues of this rapid growth that we are now facing are:

- Ensuring adequate infrastructure—roads, housing, municipal services
- Ensuring an adequate workforce—we are already starting to see shortages of skilled trades, technicians and professional employees
- Access to markets—with the growing oil production, new pipelines will be needed to access new and existing markets. We will also need new refineries or expansions to accommodate this growing supply.

Industry is working closely with governments, labor organizations and other industries to address the labor challenges. Industry is also working with several pipeline companies, refiners to address market access and growth.



Question 3: We heard your lessons about early royalty relief and expensible depreciation for oil sands plants that require high front-end capital investments. But there were additional hurdles to first-generation investment that Canada succeeded in crossing prior, with great perseverance. What fiscal and programmatic steps should the United States take to get past the hurdle of establishing a first-generation oil shale facility in the United States?

There are several aspects to encouraging first generation technologies in the oil sands. While they may not apply directly to the oil shale and tar sands in the US, the Canadian experience may provide ideas for how the concepts were applied for oil sands in Canada and could be used in the U.S. or modified to apply more specifically to the oil shale and tar sands.

In Canada, the successful fiscal and program steps included:

- Joint government and industry funding research and development—over many years starting first with government research labs and extending to pilot scale demonstration projects with multiple companies. This was more than a single program. It was multifaceted and wide ranging. It included government labs and research facilities, universities and industry pilot and demonstration projects.
- The fiscal (royalty and tax) regime was critical. While it started out as a case-by-case negotiation, it quickly became evident that the provincial royalty regimes for conventional oil and gas would not work. The high front end capital costs and the long lead time investment before production began were two unique challenges that led to a two tiered royalty regime. The first tier was a relatively low front end royalty based on production (ranging from 5% in the early years down to its current 1%). This royalty is in place until the project reaches "payout" where the revenues generated equal the costs invested. At payout, the royalty rate then increases to 25% of net profits (revenues minus costs). Regardless of the details, this two tier royalty regime was effective for helping developers cope with large upfront capital cost risks of these projects.
- From an income tax perspective, in 1996, the federal government allowed oil sands to be treated like other mining operations for tax depreciation. This allowed the upfront costs to be deducted up to the level of income from the project and made the tax treatment similar to exploration expenses for conventional oil.

Question 4: In the end, all development depends on a willing investor to invest capital. What are the risks to investing capital that might be at least partially mitigated by Government policy and legislation?

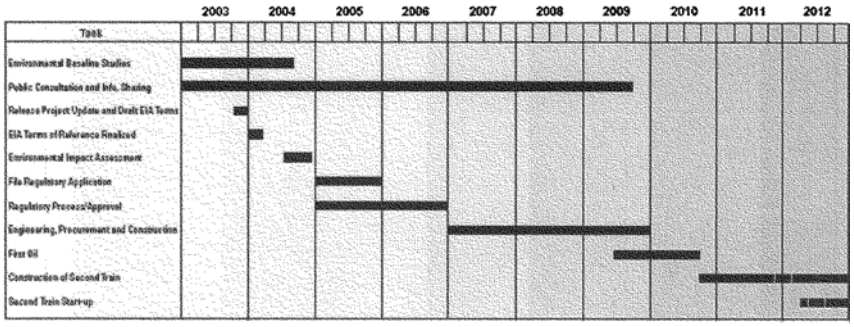
As mentioned previously, the largest initial risks in oil sands were technology and economics. While we believe that the market is the best determinant of project economics, government policy and legislation can both set a foundation of certainty and stability that can encourage the early "pre-commercial" stages of any resource development and ultimately enable commercial developments. The benefits of unlocking this development have broad public application from employment, tax base, innovation and business and economic development. In addition to technology, governments can focus on policies and legislation regarding tax and fiscal regimes, timely regulatory approvals, land management and provision of infrastructure such as roads and services that enable these developments to proceed.

Question 5: What regulatory issues should we anticipate as placing unacceptable timelines on investment payout, and how has Canada handled these?

With the large upfront capital investment for oil sands projects, the longer the time between the initial investment and when oil production begin; the higher the capital risk and the more negative the impact on the economics. The regulatory process is a major determinant of the time it takes from application to production. In Canada, the growing complexity of the regulatory process and the duplication of requirements from different levels of government are creating a longer process.

Industry is working with governments and regulatory agencies to make the regulatory process more efficient. To be clear, this does not lower the regulatory or environmental standards to be met, but is simply trying to use single window approaches or find ways to meet the needs of multiple regulators with a single application.

The recent application by Imperial Oil for the Kearl Oil Sands Project is a good example of the timelines associated with these large oil sands projects and the need for an efficient regulatory process. As can be seen on the timetable shown below, even with an assumed two year regulatory process, it will be a seven year process. Pre-application work began in 2003 and first oil production isn't expected until mid-2009.



Kearl Oil Sands - Preliminary Schedule

The Alberta Energy and Utilities Board has prepared a document titled Guidelines Respecting an Application for a Commercial Crude Bitumen Recovery and Upgrading Project that outlines the regulatory expectations for preparing an application for these projects that may be useful reference to your committee. It contains following sections:

1. General Information
2. Technical Information
3. Economic Information
4. Environmental Impact Assessment
5. Biophysical Impact Assessment
6. Social Impact Assessment
7. Environmental Protection Plan
8. Conceptual Development and Reclamation Plan
9. Solid Waste Management

The complete Guideline document is available on the Board's website at: http://www.eub.gov.ab.ca/bbs/products/guides/g23.pdf

Mr. GIBBONS. Absolutely. And Mr. Smith, we appreciate the fact that you have been able to come and join us today. We understand, of course, your historical background as the former Minister of Energy for the Canadian Government. We would hope that you would be able to address maybe the idea of: How do we cooperate, how do we get governments to work together to produce and make this issue of unconventional oil resources a conventional oil resource for America? Thank you.

STATEMENT OF MURRAY SMITH,
FORMER MINISTER OF ENERGY, CANADA

Mr. SMITH. Well, thank you very much, Mr. Chairman. It's a privilege for me to appear in front of the Committee. And I have been assigned to Washington to represent Alberta's interests here. And I must thank you, this Committee, and other committees, for the gracious welcome I have received. It's actually good to be in Washington—and you don't have to buy a dog to have a friend.

I want to comment just briefly on the role that government can play. We knew we had this outstanding commercial resource available. But you couldn't think of it as an oil resource; we had to think of it a mining resource. And in fact, because it is now truck-and-shovel, it is a mining process. We adjusted a royalty scale to attract investment.

And the royalty structure works in such a way that we charge 1 percent of all production revenues until the project—each defined, specific project—reaches a point of pay-out. After it reaches pay-out, the royalty structure then reverts to 25 percent of net royalties; which then is an appropriate economic rent for the people of Alberta, who own the resource. This is all taking place on federally owned—or what we would call "crown lands."

Transparent economic rents are a critical factor in developing this resource. We did not have to put any money, per se, toward an oil company, in terms of a direct incentive. But we recognized that with the potential and with the level of investment that they would make, that we would have to provide something that is both attractive to get that money in place, the first place; second, to develop the resource at an economical rate; and third, to have a degree of certainty that would last through the period of the resource development and extraction.

That, combined with over 20 years of shared research and about a billion dollars—Canadian dollars—worth of research and shared technology, as Mr. Stringham was pointing out, helped us come to the point where today we produce this mining resource at an economical rate, where it is delivering over a million barrels a day, on schedule; to double within five to seven years; and then to go to 3 million barrels a day before the end of the next decade. So the resource is substantial. It is commercial. It has developed new technologies.

We are also moving toward new technologies that will drop the operating costs even further, and that is using either the bitumen itself, or other processes, to substitute natural gas as a fuel. So we see our operating costs, which now range anywhere from $12 to $15 U.S., to drop by as much as 40 percent in the future.

So once you get a foundation, you can then continue to amortize your expertise, your technology, and your skills, over a long period of time. And we think the oil sands will successfully supply crude oil to this market, to the United States, for the next foreseeable future.

Mr. GIBBONS. Thank you very much, Mr. Smith. We will turn now to questions and answers for our panelists today. And I think what I am going to do is withhold my questions until the very last. I will turn to members of the Committee in order of their appearance here today.

I believe Mrs. Drake was the first on our side. Mrs. Drake, do you have any questions?

Mrs. DRAKE. Mr. Pearce was here first.

Mr. GIBBONS. Oh, Mr. Pearce. Mr. Pearce.

Mr. PEARCE. Thank you, Mr. Chairman. Mr. Godec, did you have a chance to look at the report by Mr. Savage, that actually there's not any oil in the shale, but it's in fact organic compounds that are compressed and made into oil?

Mr. GODEC. No, I did not.

Mr. PEARCE. Do you agree with that assessment?

Mr. GODEC. I am not an expert on oil shale.

Mr. PEARCE. Mr. Savage, tell me about the organic compounds that they find, and how they are converted into oil.

Mr. SAVAGE. What we do with oil shale is what "mother nature" would do if we had a couple of hundred million years to wait on her. There is not one drop of oil in oil shale; there's organic material. And we take that organic material in the form of rock; we heat it; and under intense heat, the organic material escapes in vapor form. We capture that vapor, and condense it into liquid. And this is what "mother nature" would do with the heat and the pressure of the Earth.

Mr. PEARCE. Are those organic materials available anywhere else in nature?

Mr. SAVAGE. Well, it's algae; it's fish life, plant life. This area that we refer to as the Green River oil shale deposit was covered by a lake at one time. When that lake receded——

Mr. PEARCE. What is the magic of these? They are kind of expensive to extract from rock or shale, so why don't we just gather them out of nature in easy to gather places?

Mr. SAVAGE. Well, I don't know why we don't do that, but I'm sure that a large deposit——

Mr. PEARCE. I mean, you understand what I am saying? If we are able to compress these things and just get oil from them, my question is, why go after them in the very expensive setting that they are in? Why not just figure out where they are cheaper to get at?

Mr. SAVAGE. Well, it is not that expensive any more to go after the reserve that we refer to.

Mr. PEARCE. So you can do it at the $20 level?

Mr. SAVAGE. Absolutely.

Mr. PEARCE. Do you have $15 oil?

Mr. SAVAGE. Yes.

Mr. PEARCE. How much are you producing?

Mr. SAVAGE. Well, we're producing 24 barrels a day with our current retort. And we do not run continuously; reason being is we are using previously mined oil shale which is owned by the BLM. We purchase from them. We do not have a mine open, so we're not into a commercial venture at this point. But we have run sufficiently long to have our costs validated. They range anywhere from $9.60 a barrel, to $22 a barrel. That variance is all mining related.

Mr. PEARCE. I understand, but my idea is if you are making money at, you said, $15 oil, and the price is 60, that is about 45 bucks net profit. I don't understand why you are not producing millions of barrels, because your profit increases as you generate more volume. I don't understand why we're producing 24 barrels instead of 24 million barrels; because you know that we need the energy. Tell me about the economics that keep you from doing that.

Mr. SAVAGE. Well, the difference is that we are a startup company, just having completed the research and development phase, and just beginning to move into a commercial mode which will consist of opening a mine and building out a series of 1,000-barrel-per-day retorts.

Mr. PEARCE. Mr. O'Connor, are you all——

Mr. SAVAGE. We want to do exactly what you're referring to.

Mr. PEARCE. OK. Mr. O'Connor, are you at Shell pretty involved in the extraction of shale organic materials and converting them?

Mr. O'CONNOR. Well, yes, we've been involved in this for almost a quarter of a century now. And I generally agree with what Mr. Savage just said; in that these oil shales are very immature product, and that they don't flow on their own. The oil and the gas is chemically embedded in the rock. Through time, heat, and pressure of tens—maybe hundreds—of millions of years, through this geologic time period, we would see these mature into a more conventional oil and gas field. But in the meantime, they are not free-flowing.

With regard to your questions on the economics, we think that there are some resources in the Green River Basin that can allow us to make money in a $25 to $30 oil price world. Now, the question is, why are we not doing that now? Why are we not now today producing extraordinarily large quantities of oil and gas?

First of all, this is extraordinarily difficult science and engineering and chemistry. We have a tremendous amount that we have learned, but we still have much learning to do. As just one example, we're inserting these heaters down into the resource.

Mr. PEARCE. Yes, I read that in your testimony.

Mr. O'CONNOR. Yes. Some of this resource is 1,000-foot deep to the top of the resource, and 1,000-foot thick below that. So we would literally be dropping down 2,000 feet of cables or pipe and heating the bottom thousand feet of that. We've had a very difficult challenge in terms of developing a reliable heater that will last the many years that are necessary, as the rock heats up and we get the rock's chemistry as it is.

Mr. PEARCE. OK, thank you.

Mr. O'CONNOR. In addition to that, while the big technological challenges are on the sub-surface, the big costs are on the surface, as we bring it to the surface and then have to engage in the surface

processing, the transportation, the power generation, and the other enormous tasks that would be involved from a practical standpoint.

Mr. PEARCE. I thank you very much for those comments. Mr. Chairman, my time has elapsed. Thank you.

Mr. GIBBONS. Thank you very much, Mr. Pearce. With the concurrence of Mr. Grijalva, as a matter of personal privilege, we are going to turn to Mr. Cannon for his remarks before he has to leave.

STATEMENT OF THE HON. CHRIS CANNON, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF UTAH

Mr. CANNON. Thank you, Mr. Chairman. In particular, thank you for holding this hearing. This is remarkably important. I appreciate it. And I'd ask unanimous consent to submit an opening statement for the record, or unanimous consent that anyone may submit an opening statement for the record.

Mr. GIBBONS. Without objection, any Member wishing to submit a written opening statement may do so.

Mr. CANNON. You know, we have some people here today who are dear friends. And I am not going to take five minutes; I just wanted to thank Mr. Savage for being here. And you know that we have these plaques with the material. That is remarkably nice. I appreciate that. And as I was walking over here, I was explaining to staff something about this and then, lo and behold, there we have the material to show them.

And Mr. O'Connor has been a good friend for a very long time. And we appreciate the work that you have been doing there. Mr. O'Connor, the world needs this. And as you pointed out, there are several resources around the world that are similar, that may free mankind from the burden of not having low-cost energy for the long term.

I would also like to thank Commissioner McKee for being here. He is struggling with these issues on the local level. And I apologize that I am not going to be able to be here to hear his testimony.

But I just wanted to thank you all for being here. This is incredibly, remarkably important, as you look at the pressures that are on the world today. I mean, I thought that $2 gas would be really a horrible thing; but actually a lot of nice things have come out of it, including the fact that we may be looking at some of these alternatives in Canada, in shale and in tar sands.

And so Mr. Chairman, again, I thank you for holding this hearing, and yield back.

[The prepared statement of Mr. Cannon follows:]

Statement of The Honorable Chris Cannon, a Representative in Congress from the State of Utah

Thank you Mr. Chairman for holding this important hearing on Oil Shale, Oil Sands, and Heavy Oils. As the price of oil is projected to continue to escalate, our need to depend less on foreign sources is even more apparent. American consumers have increased their demand for oil by 12 percent in the last decade, but oil production has grown by less than one half of one percent. We import 56 percent of our oil today, and it's projected to be 68 percent within 20 years. Fortunately, a solution is available.

Of the estimated 2.7 trillion barrels of oil held in the world's oil shale deposits, 2 trillion is scattered across the United States. That's more oil than all the countries in the Middle East combined.

In fact, the U.S. Department of Energy estimates that the United States is the richest and most geographically concentrated oil shale and tar sands resource in the world.

This gigantic resource of oil shale and tar sands is well known by geologists and energy experts, but it has not been counted among our nation's oil reserve because it is not yet being developed commercially. Companies have been waiting for the federal government to recognize publicly the existence of this resource as a potential reserve and to allow industry access to it.

Oil shale could allow the U.S. to become the world's single biggest oil source, ahead of all the OPEC members. The Department of Energy's Office of Naval Petroleum and Oil Shale Reserves estimates oil shale's direct economic value to the nation might approach $1 trillion by 2020, not counting other equally or more valuable strategic and national security benefits that may not be fully measured in dollars.

Today's hearing will help us to understand the potential of domestic oil to supply America's oil demand. I thank the witnesses for being here today and I look forward to hearing their testimony.

[The statement submitted for the record by Mrs. Cubin follows:]

Statement of The Honorable Barbara Cubin, a Representative in Congress from the State of Wyoming

Mr. Chairman, for three decades, this country has been on the path toward a serious energy supply shortage and an ever growing dependency on foreign oil. Transportation costs are skyrocketing; everything that rolls, floats, or flies costs more to operate. Add in global energy demand that continues to increase exponentially, and it becomes very clear that our nation is on the brink of an energy crisis.

Fortunately, adequate energy deposits exist within and just off the coast of our borders to meet this growing demand. Technology is improving everyday in how to best access these energy sources, as well as creating new renewable energy supplies. Western oil shale deposits, including those that reside in the Green River and Washakie basins in Wyoming, have the potential to play a significant role in an energy supply solution.

Through passage of the Energy Policy Act, the U.S. House of Representatives has taken an important first step toward the development of this potential resource by directing the Secretary of the Interior to develop an oil shale leasing program for the nearly 2 trillion barrels of oil shale resources located in the United States.

I look forward to hearing from our panel today what investments private industry is making to ensure the efficient development of oil shale resources in the future, as well as what economic benefits it would bring to local, state and federal economies.

Thank you Mr. Chairman for holding this important hearing and I yield back the balance of my time.

Mr. GIBBONS. Thank you very much. Turn now to Mr. Grijalva. Thanks for your patience.

Mr. GRIJALVA. Thank you, Mr. Chairman. Let me begin, I guess, directing to Mr. Savage and Mr. Godec the same question. Thinking ahead, and thinking of consequences as we go forward with, as Mr. Cannon said, this very important research and development process that we are in.

Although apparently based on some new innovations, it is my understanding your approaches to oil shale production still involve major mining operations. And if I am correct in that understanding, I just ask the general question: What specific techniques and precautions will you use to protect surface water, ground water, from depletion or contamination, to protect top soil stability, and to control the air pollution from the mining and whatever other stages of operation? Those are precautionary questions that I think will have to be asked as we go along with this discussion.

Mr. SAVAGE. Thank you. Our process is a two-step process. One is the mining. And as Terry indicated, we have to bring the rock

to the source of the heat, so it's mining, bringing the rock out of the ground. And then the second phase is processing that rock on the surface.

I can tell you that the retort, or the surface processing aspect, is fully self-contained. It's a sealed unit. It's oxygen-free. In fact, if we allowed oxygen to get inside of our retort, we would have an explosion. We would combust the shale. So it's oxygen-free, sealed under vacuum. There are no gases or emissions of any type that reach the atmosphere. The only non-condensable gas that we produce in this process is propane. And we capture that and, after processing it, that can also be a marketable product.

The mining aspect of this, relative to the environmental consideration, we apply with the State of Utah in the—we have 39,000 acres of oil shale ground under lease, which is owned by the State of Utah. We have applied for a mining permit. And they put us through the hoops and make us dot the "i's" and cross the "t's" as it relates to environmental impact. So we have geological studies conducted, paleontology studies conducted, archaeological studies, as well as the reports on our system relative to air and water control and so forth, where we disperse spent shale. And all of that is contained within the mining plan that the State of Utah will rule upon.

We are doing nothing more than what coal mining does to the environment. We go underground and we remove rock and we bring it to the surface. And you asked about methodology.

Mr. GRIJALVA. That is an interesting point. I think that there is an estimate that there is a $26 billion price tag on reclaiming coal mines across this country. And that is kind of the precaution and anticipation in unintended consequences that I think need to be looked at, as well.

Mr. SAVAGE. One of the things that I might mention is, in this area where we are currently operating there are mined out and abandoned gilsonite veins. Now, you wouldn't want to walk around in this area in the dark. We're talking about 50-foot-wide veins that maybe go 1,000 feet deep, and they go for miles across the surface of the Earth. The State of Utah has asked us to take the spent shale and begin filling in these cavernous areas.

Mr. GRIJALVA. Thank you, Mr. Savage, and thank you for the visual. Appreciate it very much. And I had asked the question of Mr. Godec, as well, but for the sake of time, let me begin with him on the second question to both the same gentlemen. With your anticipated ability to produce fuel from oil shale at such a low price, can we correctly assume or expect that you will be able to operate without any government subsidies or tax breaks?

Mr. GODEC. Is this directed to me, or to Mr. O'Connor?

Mr. GRIJALVA. We will begin with you this time, because I cut you off on the other one.

Mr. GODEC. No, I was really not referring or speaking to oil shale. And so I'm really not qualified, I don't think, to talk about the economics of oil shale production.

Mr. GRIJALVA. Mr. Savage? Mr. O'Connor?

Mr. SAVAGE. Well, we have never asked for, neither are we asking now for government subsidies. I think the position that Canada has taken would amply suffice for our needs, in some sort of

royalty breaks when working upon Federal ground, and maybe some tax investment credits, those kinds of things.

Mr. GRIJALVA. And if I could direct a question to Mr. O'Connor, well, the same question about the process is relatively low market in terms of cost and prices. Am I correct in assuming that that can be done without subsidies or tax breaks? Same question.

Mr. O'CONNOR. Shell has been at this for almost a quarter of a century, and we've done it all on our own land. We've done it all without any government involvement or subsidies whatsoever. We're not seeking any money from the Federal Government going forward; despite the fact that a large-scale commercial operation will be very substantial in its capital expenditures.

As my testimony does indicate, though, we think that there are areas where clarification and some parameters need to be set around the issues of Federal royalties; since the Federal Government owns somewhere between 72 and 80 percent of all the oil-shale-bearing lands in the basin. And also, there are some issues involving tax credits, where they are or in the past have been available for a variety of other type of non-conventional fuels. And to the extent that it becomes appropriate to have discussions to seek clarification on which of those should be considered in the future, we think that oil shale should be part of those discussions.

Mr. GRIJALVA. If I may, the last question, Mr. Chairman, Mr. O'Connor, you mentioned BLM's new experimental leases. Do you anticipate, or do you think Shell will seek one or more of these leases in the near future?

Mr. O'CONNOR. Shell, in fact, has applied for an R&D lease on Federal lands. You've raised an interesting question, that I'm so glad that you asked about one or more. My testimony in the written form indicates that there is an 85-year-old provision in the Mineral Leasing Act of 1920 that restricts companies or individuals from acquiring more than one oil shale lease anywhere in the United States. It's ironic that that still exists.

That provision and that restriction was created for all the other commodities, too: oil, gas, coal, phosphate, and all the other leasable minerals. And with the exception of oil shale, those restrictions have all been modified throughout the years.

So we think it is extraordinarily important for Congress to take a look at this. Because otherwise, if a company does develop—does secure a Federal oil and gas lease, and then successfully develops a project on it, it is then out of business in terms of any further development on Federal lands.

And we're not suggesting opening up the flood gates in terms of unrestricted leasing, but this single-lease limitation really does cry out for consideration in the 21st century.

Mr. GRIJALVA. Thank you, Mr. Chairman, for the additional time. Appreciate it.

Mr. GIBBONS. Mrs. Drake.

Mrs. DRAKE. Thank you, Mr. Chairman.

Mr. Savage and Mr. O'Connor, it sounds like you are both doing this. I wondered what the regulatory process was, and how long it took you to be able to get your permitting to be able to do what you are currently doing, and what you think you are looking at—of course, if you go out on Federal lands, it is going to be another

process—what the timeframe is going to be for you to do what you would like to see happen. What it took you to get to where you are, and what you anticipate.

Mr. SAVAGE. Well, currently, we have a research and development site which consists of an acre of ground in the middle of several thousand acres that we have under lease with the State of Utah.

Mrs. DRAKE. OK.

Mr. SAVAGE. And the permitting process for this research and development aspect of the project was not long in coming. We were able to obtain the necessary permitting within a few weeks time.

The mining permit which we have applied for, we first applied for that more than 12 months ago. And that's still in the process and will come up—as I understand it, within the next couple of months it will come up for a 30-day public review. And after that review, we may be asked to give additional information or more detail as to our mining operation plans. And then it will be ruled upon, and we'll either be permitted or not. We anticipate being permitted.

Mrs. DRAKE. But you don't see it as a very long, extensive process, like we have heard in other committee meetings with other types of things that are being mined?

Mr. SAVAGE. No. It hasn't been on the state level. As we look at the Federal requirements, that could take substantially longer. And if we would have one request in addition—I think Terry made a very good point about the Mineral Act—but instead of subsidies, we would like to see more cooperation of the Federal Government in trying to move this project forward, through some relaxation, if you will, of the requirements to get to where we need to be.

Mrs. DRAKE. Mr. O'Connor, did you want to add anything?

Mr. O'CONNOR. Yes, ma'am. Despite the fact that we don't actually mine any of the resource, because of the peculiarities of the State of Colorado regulatory regime, we're regulated as though we are a mining operation. Having said that, in the past, because of the very de minimis size and disturbance involved in our five research projects so far, time and complication has not been an overriding factor for us in the permitting process.

But I hasten to add, this has all been done on our own land. When you overplay the involvement of Federal lands, along with the larger and more complex size of a commercial operation, we fully expect that, under the best of circumstances, it's going to take us probably five years, at least, to be able to permit our first commercial operation.

Now, I mentioned in our testimony that we're hoping to make a final investment decision for a large commercial operation by the end of this decade. That means that, despite the fact that our technology is yet not proven at commercial scale, although we're getting increasingly optimistic, we literally have to start now with gathering environmental data, preparing environmental impact statements, starting down that road, in anticipation of what under the best of circumstances may very well be at least five—and could be 15 or 20—years of permitting activities.

It is here where we will desperately need government help. And we're not here seeking any waiver of environmental standards, or

waiver of substantive environmental issues. But the large and daunting looming of multiple sequential permitting processes, each of which could be very complicated, each of which could be subject to lots of controversy for those that don't want to see any oil shale development, could extend to the point where what looks like a very attractive project or projects for us in the future could lose their luster as the years and the decades could drag out.

Mrs. DRAKE. And Mr. Stringham, I wondered if you could tell us how the process works in Canada, and the regulation, the timeframe. I did notice that you are also in Saint John's, Newfoundland. I will actually be visiting there in August.

Mr. STRINGHAM. Oh, congratulations. It's a great place to visit.

Mrs. DRAKE. Well, it is. My mother lives there. I go quite frequently.

Mr. STRINGHAM. Perfect. Well, then you understand that, as well. The regulatory process in Canada is not much different. If it is under provincial control, then certainly you can move more quickly. But what we have in Canada is we have provincial and Federal regulation overlapping, very similar to state and Federal here. And so from that perspective, for a large oil sands plant, certainly it can take a two- to three-year process.

Mrs. DRAKE. A two- to three-year process?

Mr. STRINGHAM. Two- to three-year process.

Mrs. DRAKE. Not 15 to 20?

Mr. STRINGHAM. Yes, that's correct. Although, you know, for the early days, certainly, it took longer than that. But we really tried to work it down to a two- to three-year process.

Mrs. DRAKE. Thank you very, very much. Thank you, Mr. Chairman.

Mr. GIBBONS. Thank you, Mrs. Drake. Mr. Jindal.

Mr. JINDAL. Thank you, Mr. Chairman, first of all, for calling this hearing. Given the price of energy in our country, I think this hearing couldn't be more timely. And I want to thank the witnesses for their information, as well.

The first question I'll direct at Mr. Savage and Mr. O'Connor, but I invite any of the witnesses, certainly, to respond to this. I am just curious, as we have heard about the wonderful resources that are potentially available to us right here in our own country, across North America, I am wondering, what are the most important steps we can take in the Federal Government to encourage timely production of a large volume of oil, not only from oil shale, but from the oil sands and some of the other resources we have heard about today, as we think about completing our work on the energy bill? I am just thinking in concrete terms. What do you see as the three biggest barriers? And what are the three specific things we could be doing in Congress to help speed along the development of this process?

Mr. SAVAGE. Well, I think we've mentioned a couple. When we realize that 80 percent of this ground that we speak of, oil shale property, is owned by the Federal Government, there has to be some cooperation from the Federal Government as to the land usage. The leasing of the land, as has been stated, it'll be required that there be more than one lease granted to one company. That's a given. Help with companies to meet the environmental impact

issues; but to help us, and not stalemate us, in moving those forward on a more quickly [sic] basis, more rapid basis.

Mr. O'CONNOR. Just referring in general terms to our written testimony, we've identified six areas where we think it's strategically important to have legislative and/or regulatory proactive support from the Federal Government.

The first is more on the policy level; is to really have an official declaration from the highest levels of this Government, both Legislative and Executive, that oil shale is a strategically important energy fuel which should be developed on an expedited basis, if it can be done in an environmentally acceptable and economically feasible manner.

Why is that? Well, very honestly, because of the failures of the '70s, there is so much misperception, and thus negative overhang, involving oil shale, that we think that even many of our friends remember the past failures—that largely precipitated from a rapid decline, an unexpected decline, in oil prices—and are not really particularly focusing about the advances of technology. And so as a result, in many cases, we are finding ourselves attempting to try to push something up a waterfall. And if we can get into a policy pull position, that can really make a big difference.

Second, encouraging and directing the Interior Department to develop a commercial oil shale program. And as I said, you know, they have taken a very important initial step, but they need to follow through to develop—they've had authority since 1920. And except for four oil shale leases that were issued in the 1970s by Executive Order from the President, no oil shale program, leasing program, has ever been developed. And certainly, the time has come. And we applaud the Department for taking this first step.

Third, we've already mentioned the single-lease limitation, which can really be a show-stopper for long-term investment and approvals necessary because of the extraordinarily long capital that is needed.

Fourth, the Secretary has unbridled discretion to set royalties at whatever rates. And while that doesn't require specific legislation, we think that the extraordinary amount of capital at the front end, and the high-risk capital, and the high technical risks that are involved in first-generation facilities that'll be the first in their kind in the world, literally, need recognition that some parameters on royalties, particularly in the first iteration of royalty setting, be set; perhaps along the lines of what the Canadians did.

I've also represented or mentioned earlier about the permitting needs where, instead of getting involved in the endless cycle of multiple sequential permitting that could drag five years into multiples of that, some Legislative and Executive efforts to try to consolidate these into more rational concurrent reviews will make enormous sense.

And finally, just mentioning that there are some ambiguities in the tax laws regarding whether or not oil shale would qualify for some of the same type of tax treatment that other unconventionals do, also needs to be clarified. Thank you for the question.

Mr. JINDAL. Thank you.

Mr. SAVAGE. May I make one more comment along those lines? There's a tract of land in eastern Utah that's owned by the Federal

Government which we refer to as "UAUB." This is a tract of land, approximately 10,000 acres, which was leased to the consortium of Phillips, Sun Oil, and Sohio, back when the commercialization of oil shale was underway.

They have developed—"they" being the consortium developed—an underground mine which, upon abandoning their project, that mine was turned back to the care of the BLM. And at one time, it was attempted to reclaim—the BLM wanted to reclaim that mine, for many and various reasons. It remains open, although there has been some signs of closure.

If a company like Oil-Tech, which is ready with a surface retorting process to move forward, if we could lease that ground containing that mine, we could move forward very, very quickly. We could be producing thousands of barrels of oil a day very quickly.

Mr. GODEC. Just a couple of comments to reiterate, I think, in kind of applying it across the board to all unconventional oil resources, not just oil shale, I think there's a lot that we can learn from our neighbors to the north in Canada about effectively, through public/private partnerships, encouraging and facilitating the development of a resource that's technically challenging and unfamiliar to much of the operating community.

And that was done in Canada, and it's what I'm recommending in my recommendations to this Committee; to include, you know, both updating and publicizing the information on the geologic characteristics of the resource, where it is, what its characteristics are; publicizing current technologies and how those might be applied to these resources through demonstration projects and field pilots; taking that best technology today and looking at it to see what else we can do through research and development and improved science to improve the recovery; and then providing fiscal incentives to help basically share the risks between government and industry in going after these new technologically challenging projects in a way that both facilitates their development, but in the long run is not a net subsidy forever for these kinds of resources.

I think you can look at unconventional gas resource development as a prime example where, here in the United States, through the combination of research and development and effectively targeting fiscal incentives, we've been able to turn what was once an obscure, unconventional resource—tight gas and coalbed methane—into a resource now that provides one-third of our domestic natural gas supplies.

Mr. JINDAL. I want to thank the witnesses. My time has expired. I just want to echo two things. One, I want to thank each of you for your specific recommendations. Mr. O'Connor, I think you said it best, in that it is incumbent upon us to develop our technologies in an environmentally sensitive way to take advantage of these energy resources that are present in our Nation.

And second, even though, Mr. Stringham, I didn't get a chance to ask you the question I would have asked, I think we have a lot to learn from our neighbors to the north. And we certainly appreciate your coming and sharing with us how this regulatory regime has worked in Canada. Thank you.

Thank you, Mr. Chairman.

Mr. GIBBONS. Thank you very much, Mr. Jindal. And in fact, I want to follow up a little bit with where he left off, and maybe question Mr. Murray [sic] with regard to the relationship.

Our next panel that is going to come up is going to talk about the state-county relationship and their involvement, of course, with this resource. I would ask you a question. The Canadian Government, with regard to the province of Alberta, its local communities, what was the relationship? And how did they work together with the stakeholders in this in order to develop these oil sands in Canada with such an expedited timeframe, if you will?

Mr. SMITH. The original Great Canadian Oil Sands plan started in 1977. The first barrel out was at $35 U.S. And it seemed at that time that the path was going to be fairly long. The ownership structure of the resource is the government of Alberta, the province, owns the resource; and the Federal Government oversees inter-province or inter-state movement of that product. So the local ownership did play an important role.

The Federal Government recognized the value of the resource for all of Canada, and contributed by putting money into a joint research fund, called the Alberta Oil Sands Technical Research Authority. That authority shared technologies with the private sector, and shared funding with the private sector over a 20-year period, to the tune of about $800 million.

The companies would invest their money into oil sands development, into oil sands technology, and then would be treated differently through this stage. In 1993, what we did is started to take each individual lease that was rented by the oil company and give them certainty so that the period of development they would be able to keep the lease. Second, they would file an annual mining plan, an annual review plan, an annual audit plan, with the province of Alberta.

They would be regulated in environmental practices and mining operations by an arms-length regulatory body called the Alberta Energy Utilities Board; which today monitors their activities on a daily basis.

And then, in 1996, we started on what we call the generic royalty program; which then said, "One percent of your production revenues, until the project is paid out; then we move to a 25 percent royalty structure of net revenues." And that really was the kick start.

And that was combined with a Federal contribution of accelerated depreciation, or accelerated capital cost allowance, where they could write off in one year what they had spent in the terms of that year's investment.

Those factors really contributed to recognizing the front-end-load risk of capital; and through that, helped us bank a total investment of some $80 billion now into these oil sands. So it was very much certainty, very much transparency, and then a working partnership of shared technologies, that helped stimulate the development.

And those started to move in terms of, if you mine the first 80 feet of oil sands, you can mine it using truck and shovel. However, to make the deeper deposits economical, we use a process called steam-assisted gravity draining. And what that is, is we inject steam into the bitumen and we then heat the rocks up enough to

make the bitumen flow into a pipe, and which is then piped away. Eighty percent of our oil sands resource will be developed through this system.

That technology was developed and is now shared by more than one company. And I think that that non-proprietary sense really accelerated our development. And so each time we leapfrogged in technology, we were also able to put additional downward pressure on cost; to the point where we, you know, see this now competing worldwide on a very favorable basis.

The last thing—and you know, from a conservative government you sometimes wonder about the wisdom of it at the time—but in fact, the government of Alberta owned 10 percent of the oil sands, the initial oil sands development, and was an active equity partner; and only discharged its equity interest in 1995. But I think that what we found is that actually holding an equity interest was more of a hindrance than it was a catalyst. And so by divesting, we then in fact accelerated the growth and development of the oil sand.

Mr. GIBBONS. Well, Mr. Smith, let me follow up with what you just told this audience. I think it is very important to note that the Canadian Government, and the province of Alberta, stuck with this program back when oil was on the market for less than $20 a barrel—probably in the $10- to $20-a-barrel range—which says a great deal about the confidence of the Canadian Government, and the Alberta government, as well, with approaching this issue. To get to where you are today of producing 1 million barrels of oil per day from these oil sands I think gives great credit.

We are pleased that you had the foresight, but also the gravamen, to stick with it, as they say, so that you are now in that position to demonstrate I think to not just the world your ability to produce, but you are actually demonstrating a marketable product today that when you began was questionable at $35 a barrel.

I think it is just a remarkable story that you have to tell us, and we are very glad that you were here to explain that.

Mrs. Drake, do you have any additional questions for this panel?

Mrs. DRAKE. No, thank you, Mr. Chairman.

Mr. GIBBONS. You know, I have several questions for this panel. But I notice that the time is dragging on. We have kept you gentlemen here for an hour and a half. We have a second panel.

I would like to mention that we would have some written questions to follow up to ask, very important questions about the process, about the efficiencies. There will be questions about going forward with technology: how do we share technology; how do we develop this resource in the short-term future? I think for this country, for this Nation, working together, developing technologies, are critical for the development of this resource, to overcome our dependence on foreign oil.

We as a nation owe it to the people of this country to do what we can to expedite this energy resource, so that we have the ability to provide oil for the economy to make it run in this country. So you gentlemen sitting here today have opened the door to, I think, a very bright future.

And I think we can safely say that our energy future with regard to oil and gas has yet to see its brightest days, because of what you

are doing in the oil sands, the oil shales, and the heavy oil unconventional market today.

So with that, I want to thank each and every one of you all, excuse this panel, and call up our next panel, if I may.

The second panel will be Mr. Russell George, Executive Director of the Colorado Department of Natural Resources; and Mr. Michael J. McKee, Commissioner, Uintah County, Utah.

While we are waiting for these gentlemen to approach the witness table, let me submit for the record the testimony of Juan Antonio Granados, President of Shale Oil Information Center, Incorporated.

[The statement of Mr. Granados submitted for the record follows:]

Statement of Juan Antonio Granados, President, Shale Oil Information Center, Inc.

Liquid Fuels from American Shale and Tar Sands—The Challenge—The Mission

Today, 70 percent of all liquid fuels are used to sustain our efficient transportation system; the envy of the world; our Achilles heel. Damage to it, will destroy our economic system. What we are talking about here today will take 10 or 15 years to be fully implemented "if we start this year, enough time for the enemies of America, in the Middle East and in Venezuela to bring us to our knees. Thereto, our challenge here today. And $150.00 oil, maybe?

In 1979 the late Dr. Armand Hammer prophetically wrote "The escalating price and growing shortage of petroleum are beginning to influence our life styles and employment patterns, and to compromise our standard of living". He said this while promoting the development of our oil shale resource. What happened?

This Congress can elect to take the high and responsible road to promote the full and reasonable development of the Colorado/ Utah/ Wyoming oil Shale and tar sands resource as soon as possible. This is the true national challenge and should be the mission undertaken.

In 1976, two short years after we were all waiting in line to get gas, the then President Carter gave a speech announcing an energy program that he described as the "moral equivalent of war". At that time there was still plenty of easy to discover and to recover oil, and, plenty of excess capacity at OPEC's disposal as well as outside OPEC.

Both Alaska and North Sea oil were in a full upward production swings. But today?. Today, we are not as fortunate.

There is plenty of evidence that has emerged over the past decade that the epoch for easily, and cheaply discoverable oil is behind us now. Yet the world demand for liquid fuels has been steadily increasing and has already approached available maximum production. This steadily increasing demand "which has been underestimated by many experts, has been to satisfy the new needs for liquid fuels in the newer emerging economies of Eastern Europe, India, Southeast Asia and China.

This past year alone, the combined demand increases by both China and India have exceeded the yearly, daily average net new production capacity additions from non-OPEC sources. This newer capacity additions had been averaging about 1 million barrels per day every year for the last 10 years, and are expected to accelerate to about 1.5 millions barrels per day per year, for the next several years. But this is not enough, so our dependence on OPEC oil will continue to increase, and so thus our vulnerability.

Therefore, we have to expect that without increases in new liquid production from other sources, such as shale oil, supply growth will constrain future demand growth, and our economic growth and well-being will slow down or deteriorate. The only time, supply additions will grow faster than demand, would be if there is a severe recession.

How can we as a nation sit and watch impassively while the mayor oil companies are all loaded with tons and tons of cash, not knowing what to do with it, while our oil shale resource remains unused?

Does it not, therefore, make sense for us to create the "right" incentives for the oil companies to invest all that accumulated cash? Does not this accumulation of cash signal two evident warnings—One, that the oil companies are short of available new prospects, and two, that whatever is available is considered too risky for

them to invest? Does this not suggest that this is an unsustainable national security situation?

Our responsibility goes beyond proposing to Congress a limited program to develop the technology to extract the liquid from the rock, it goes to propose a comprehensive program that addresses all the issues and create the necessary incentives and guarantees so that our cash loaded oil companies proceed to the intense and responsible industrial undertaking of massively extracting the oil from the rock from the entire shale and tar sand resource. A maximum priority of our National Security.

If adequate market incentives are in place that eliminate or reduce market risks and assure reasonable profits, the oil companies will come up with the technology. We will shorten the time for the availability of the fuel from the shale and the tar sands by many years.

The Bureau of Land Management (BLM) must again make available the land containing the shale oil to these companies. Our government must provide a guarantee that each barrel of liquid fuel that goes into our domestic pool and that was extracted from U.S. shales or tar sands is guaranteed an indexed minimum price that reduces investment risk and provides an adequate return to the investor. My educated guess is that that price today is equivalent to $50.00 or $60.00 a barrel of crude. This guaranteed minimum is needed so that there is not a repetition of the earlier mistake with the shale oil program. The extraction projects were abandoned, when the price of crude dropped and when the newly elected President Reagan cancelled the subsidized purchases of fuel from U.S. shales by the Department of Defense. An accelerated depreciation schedule until the year 2035, that would allow writing off in less than three years the equipment required to extract the oil from the rock, should be authorized to stimulate industry to make the enormous investment required. Finally a ten year tax holiday beginning on January 1, 2006, ending on December 31, 2015 to incentivate industry to jumpstart the reasonable commercial development of the resource.

I want to share with you my experience in the ethanol for fuel program which was successful and very profitable. It is important that we draw lessons from the past so that we can set the right course from the beginning. My contributions were essential to getting the alcohol fuels program going. Later my commercial activities continued to be profitable to me and many others. I had the opportunity to watch from the sidelines what happened to the alcohol fuel program. Mainly its successes. Successes and failures, also occurred in the earlier shale oil program. We cannot afford for the sake of our national security and our economic survival to make the same mistakes.

Congress came out with a program which incentivated demand and use by exempting from the excise tax on motor fuel each gallon blended with 10 percent anhydrous ethanol. This was sufficient to encourage a large grain processing company to begin making the investments in the distilleries to manufacture the ethanol. For a while there was only one big producer, since the other large grain processors did not believe that the incentives would be politically sustainable over the long term. The one company accepted the political challenge, and today, 25 years later all of them are in the business and the incentives continue to exist. And the excise tax exemption continues to exist, with additional incentives for the production of ethanol.

If similar market incentives were made available to each barrel of liquid fuel produced from American shales or tar sands, similar considerations would be given in the board rooms of the big oil companies. It is my belief that the risk that these incentive could be discontinued could be managed by a coalition of blenders, refiners, consumers and Americans concerned with the security of our transportation system. Let's not forget that what the American consumer wants most is the ability to gas up, and not wait in line. They are willing, as demonstrated by the recent experience over the last few months, to pay well over $2 per gallon as long as that gasoline is available to them. So supply reliability is upper most in the consumer's mind, more so than prices. Europeans, have gotten accustomed at paying over $5/gallon, and our consumers will eventually do likewise, if we can prove to them that the alternatives are long lines at the gas stations.

It is time to do what must be done. It is today that it must be done. Ten years from now it will be too late. We owe it to the brave young men and women that are risking and losing their lives defending our freedoms. Let us do our part.

Mr. GIBBONS. And gentlemen, before you sit, we still have that procedure to go through of swearing you in. So if you will, just raise your right hand and repeat after me.

[Witnesses sworn.]

Mr. GIBBONS. Let the record reflect that our witnesses answered in the affirmative.

We turn now to Mr. Russell George, Executive Director, Colorado Department of Natural Resources. Mr. George, welcome to the Committee. Thank you for coming this far to help us better understand this issue. The floor is yours. We look forward to your testimony.

May I say, also, that we have a little clock in front of you that shows five minutes. If you can sum up, we have your written statement, which will be submitted in complete order for the Committee. So if you want to summarize and talk a little bit about your ideas in the five minutes you have, that is also very helpful.

So Mr. George, the floor is yours.

STATEMENT OF RUSSELL GEORGE, EXECUTIVE DIRECTOR, COLORADO DEPARTMENT OF NATURAL RESOURCES

Mr. GEORGE. OK. Thank you, Mr. Chairman and members of the Committee.

I did take advantage of your rule that allows me to add appendices to our own comments. And because we're talking about state and local government aspects here today, I took that opportunity to enclose a recent statement from a consortium of local governments in northwest Colorado that I thought was very important to share with you. And I'm quite confident that as we talk about Utah, local government views will be very similar and very compatible. So I would urge you to also note that that document is present in my remarks.

A very complicated subject, very hard to summarize in the few minutes; so I'm going to just bounce across what I think are the main points that we think about at the state level. And certainly, I want you to know that Colorado is a very willing partner in the development of this resource. We regard the resource as abundant, as we've been hearing here today, and its development very much in the national interest.

But we're very specific about some conditions of how the development of that resource should proceed. First, we would agree with others that technology and environmental oversight must be very rigorous, from beginning throughout.

Second, we believe that development must use the best available practices, best management practices, to minimize all impacts that come from this kind of heavy industry.

Next, we believe that state and local needs must be anticipated ahead of time, and some arrangement made ahead of time for funding; and that development on public land—and in northwest Colorado, this will occur mostly on public land—must be prioritized by resource and region. Just noting that in the last 20 years, since we had the last oil shale effort, we now have on this same property a rapidly expanding natural gas development. And there are other resource uses also existing that all need to be prioritized, and allow all to work together.

Also, it's our view that the cumulative impact of mineral and energy development on all public lands, as well as private lands, must be mitigated.

Colorado has consistently supported the development of the oil shale resource in western Colorado. But we've insisted, and would again insist, that the projects be fiscally and environmentally sound from beginning and throughout, and that the communities, local governments, do not incur extraordinary economic burdens. The development of the energy project must pay ahead of time its own way, so that the remaining communities can keep pace but not have to generate other resources to respond.

Oil shale leasing on top of existing energy development and changing land uses—for example, we have increasing tourism and recreation; we have an expanding urban population throughout western Colorado—all of this may put more pressure on an already fragile ecosystem and public temperament.

The response to that, of course, is we need to be careful, be respectful, as we go forward. We think we should go forward, but paced and respectful is the way to do that.

So there are three things that we think we can do and should do. Federal financial support must be sustainable over an extended period of time, to encourage private sector investment. Also, a thorough environmental review process must occur. And, a financial safety net for local governments that allows for growth to pay its way and allows front-end financing.

Three things should not occur. This is something we've learned from our history and our past mistakes. One, processes that preempt or supersede local and state land use and environmental processes should not occur. In other words, we can't have the Federal system saying, "We'll supersede local and state rules and requirements." We can do this together in a type of joint review process, but not one over the other.

The development of technologies cannot occur without adequate oversight. We need to ensure both public acceptance and environmental compatibility.

And also, the national effort must address financial and infrastructure needs at the local level. And we have a number of ways of doing that. There is a revenue stream, because this is public land, that can help us do that.

I think that's enough time for now. I'll be available for your questions, Mr. Chairman. Thank you very much.

[The prepared statement of Mr. George follows:]

Statement of Russell George, Executive Director, Colorado Department of Natural Resources

Mr. Chairman, thank you. I appreciate your invitation to participate in this hearing. I am Russell George, Executive Director of the Colorado Department of Natural Resources. As the lead state agency responsible for natural resource management, I appreciate the opportunity to provide our perspective on renewed oil shale development in Northwest Colorado.

We are excited to be partners in this effort to move our great nation closer to energy independence. With perhaps as much as two trillion barrels of oil locked in the shales of western states, this vision is achievable in our lifetimes.

As a lifelong resident of "Shale Country", I would like to share some thoughts with you on three decades of lessons learned regarding the impacts and possible tools to manage the development of the resource successfully.

Background Principle

The State of Colorado has consistently supported the development of oil shale resources in Northwest Colorado since the Arab Oil Embargo of the early 1970's. Our focus has been on making sure that the projects are fiscally and environmentally sound, and that the communities do not incur extraordinary economic burdens. As history has shown, if development pays its way, the community impacts are less if the projects do not materialize.

History

Let me summarize the key elements of the oil shale development cycles of the last three decades.

Oil Shale Lease Bids. The federal government leased two tracts in each state—Colorado, Utah, and Wyoming—in the early 1970's. Bonus payments accompanied each of these leases—that determined the winning bid for the lease. Half of those bonus payments were distributed back to the state. The General Assembly established the State Oil Shale Trust Fund and Program which developed planning and coordination mechanisms for federal, state, and local governments and provided funding for designated local government services and projects ($100+ million). The goal was to mitigate the "boom town" syndrome.

The Energy Mobilization Board. As the energy crisis worsened in the late 1970's, the Executive Branch of the Federal Government pondered a national board that could declare the development of a resource in the national interest—thus preempting local land use regulations and much of the state permitting process. The Western Governors, in particular, led the effort to oppose this preemptive measure by the federal government. The Board never materialized.

Synthetic Fuels Corporation. Congress funded the Synthetic Fuels Corporation to initiate oil shale projects in a manner that would allow several technologies to develop simultaneously. Congress allocated $15 billion in price guaranties and price incentives that were competitively awarded on a multiple year cycle. In a large part, this approach made the federal government a partner in accelerated technology development.

Joint Review Process. In response to the national focus on the oil, gas, oil shale, coal and uranium resources in Northwest Colorado, Colorado developed the concept of a Joint Review Process. That process consisted of a centralized facilitation of the permit process at the local, state, and federal level. The Joint Review Process Program determined the timelines of the various required permits, coordinated the scoping process for the environmental impact statements, and facilitated public hearings and public comments. The overall coordination of the effort could allow for the application of several permits for an individual project to occur simultaneously. All the major oil shale projects, associated power plant projects, and coal mines used the Joint Review Process.

Cumulative Impacts Task Force. In addition to the permitting and environmental analyses related to the simultaneous development of multiple resources, the State of Colorado was also concerned about the fiscal impact to individual communities and counties in high development areas. To that end, the state developed the concept of the Cumulative Impacts Task Force that modeled the budgets, revenues and expenditures of 104 jurisdictions in Northwest Colorado. The key task was to determine what projects would cause what economic impacts to what jurisdictions in what years based on different population and development scenarios.

The effort proved to be extremely valuable when Exxon closed its Parachute Creek facility. At that time, because of the front-end analysis work, the distribution of energy impact funds, and the use of the Oil Shale Trust Fund, long-term economic impacts were manageable. At the time of the Exxon pullout, only one school district had a multiple hundred thousand dollar residual impact.

DOE Technology Partnership. In the late 1980's, Occidental Oil under the leadership of Armand Hammer, proposed the cooperative development of an improved oil shale technology at the C-b Oil Shale Tract in Northwest Colorado. This was to be a 50-50 partnership of Occidental and the Department of Energy. Through the work of the state, the Department of Natural Resources, and the Associated Governments of Northwest Colorado, a seven-year commitment of funds was secured from the Department of Energy for this demonstration project. The other oil shale states contributed to the technology analysis for the project. The primary market was not for processing shale oil into motor fuels, but as chemical feedstocks for other uses. The project terminated upon the death of Armand Hammer when corporate directions were changed.

Technology and the Environment

In the 1970's and 1980's, the Project Independence Technology Assessments and the Synthetic Fuels Corporation financial plan focused on both in-situ (in the ground), surface, and modified in-situ technologies. The goal for synthetic fuels was an industry that would convert coal, tar sands, and oil shale to liquid fuels at a level of two million barrels per day by 1992—the majority of which would have come from western oil shale.

The dimensions of the proposed technologies were immense. A surface oil shale mine associated with a minimum-sized (50,000 BPD) commercial plant would be comparable in size to the largest iron and copper mines in the world. This scale was necessary since it required 2.5 tons of rock to produce one barrel of oil.

Underground (in-situ) processes would have recovered less resource. Such mines would need to produce as much as 100,000 tons of rock each day to support a 50,000 BPD facility. The ore would be processed (retorted) above ground. Disposal of the spent shale in some cases would have filled valleys.

The most advanced technology was modified in-situ. That technology mined a portion of the deposit by conventional methods for surface processing. The remaining shale was then fractured by underground detonations, the rubble ignited, and the oil transmitted to the surface. This process would recover less, but with less surface impact.

As you can see, the surface area requirements for mining, retorting, or spent shale disposal were significant. Costs were enormous even in 1980 dollars—an average of $2 billion for each 50,000 BPD plant. Based on the applicable 1977 Clean Air Act standards, production in NW Colorado would have been limited to 400,000 BPD. Water requirements for a 50,000 BPD facility would require 8500 acre-feet per year of water.

In the end, the oil shale industry collapsed of its own weight—given the volumes of material to be removed and processed, the enormously fluctuating world oil price, and the lack of a consistent national vision for the development of this resource that could focus private capital investment.

While we do not know the specifics of the technologies that may be pursued over the next decade, we do know water availability, materials handling, power requirements, and transportation networks must be assessed in detail and the impacts mitigated appropriately.

What Worked—What Didn't Work

If the Federal Government is to contemplate a renewed oil shale effort, it must do so based on the lessons learned over the past thirty years. While the technologies are changing, so are the characteristics of "energy country" in Northwest Colorado.

As in the 1970's, we have record coal production that is straining existing transportation networks. We have record natural gas production levels and increasing permitting for natural gas development. The diverse development of this resource has dotted the landscape, increased truck traffic on county roads, and access to the resource has impacted many private landowners where the surface and mineral estates are severed. Additionally, there is a growing public sensitivity to in-situ activities, such as fracking with "proprietary fluids".

This development overlaps an area with increasing tourism and recreation opportunities and an expanding urban population. Oil shale leasing on top of this existing network of energy development and changing land uses may put more pressure on an already fragile ecosystem and public temperament.

We do not control world oil markets, nor do we control the actions of OPEC. Therefore, the development of oil shale cannot be purely price driven. It must be a commodity of national interest developed on public lands in the national interest. That implies a prioritized use of public lands for the development of specific resources. Federal financial support must be sustainable over several decades to encourage private sector investment. An environmental review process must be thorough. A financial safety net for local governments that allows for growth to pay its way, and allows front-end financing of some infrastructure needs and analytical tools, is essential.

All this said, the implication is that bonus lease payments from federal leases for local government facilities and services are good. Long-term federal financial support that fosters private investments is good. A coordinated permit process with adequate public input is good. And analytical tools that allow state agencies and local governments to anticipate the timing and amount of revenues for impact mitigation are essential.

What will not work are processes that preempt or supersede local and state land use and environmental permit processes. What will not work is the development of technologies without adequate oversight to insure both public acceptance and

environmental compatibility. What will not work is a national effort that does not address financial and infrastructure needs at the local level.

Colorado Recommendations

Colorado is excited to be a partner in the development of a resource that is both abundant and in the national interest. But it does intend that technology and environmental oversight be rigorous, that development use the best available practices to minimize impacts, that state and local needs are anticipated and funded, that development on public land be prioritized by resource and by region, and that the cumulative impact of mineral and energy development on both public lands and private lands be mitigated.

Oil Shale Lands Suitable for Development. Given the density of natural gas and coal development in some areas of NW Colorado, the need for recreational/wildlife habitat/undeveloped areas, and the network of privately held oil shale lands that did not exist in the last boom, the federal government must determine those areas where oil shale development could be accommodated in a manner that is least disruptive to communities and existing activities. Not all types of resource development can occur everywhere. The carrying capacity of the land, communities and infrastructure must be evaluated. That will determine the suitable areas for coal, natural gas, and oil shale development.

One type of mineral and energy development today, may preclude or limit another type of resource development tomorrow. We cannot forget that a consequence of the oil shale pull-out of the 1980's, and the sustained soft energy market in the 1980's, has been the transformation of the NW Colorado economy from an energy base to a tourism, retirement, second home and recreation base—and public attitudes have changed as well. That cannot be underestimated if accelerated development is to resume.

The lead federal agency in this new effort should provide this cumulative impact analysis and identification of areas suitable for oil shale development as an element of any development and leasing plan. Furthermore, we should insist that parcels available for leasing should be of sufficient size and number to ensure that operations are commercially viable and similarly situated with lease programs for other mineral and energy resources.

Oil Shale Lease Bids. Along with an oil shale lease process that generates front-end revenue and production royalties for the federal government, the 1970's concept of the bonus bid should be applied to any oil shale leases in the future. For the tracts leased in Colorado, a sum of over $100 million was collected and distributed to the impacted counties. This economic cushion is essential to community stability, and the ability to withstand the economic shock of a project termination.

The federal leasing program to be implemented in this new effort should insure that the bonus bid concept continues, and the proceeds are distributed to the state in which the lease is located.

Federal Financial Support. Several options have been pursued through the years to fund technology development. Tax credits have been one avenue that proved very successful for coalbed methane development. Incentives like those of the Synthetic Fuels Corporation have been another. The DOE Demonstration Project route like that at Logan Wash is another. And the DOE cost-share like the Occidental C-b Oil Shale Project is another.

Oil shale technology development is still fraught with uncertainty. Once a technology appears promising, it must be field tested. And then limited commercial scale production may occur. Collectively, this could span a decade or more. But the lesson learned from the 1970' and 1980's is that any financial incentive program must have a duration comparable with the timeframes for private investment that include a realistic timeframe for technology development and implementation, or the private dollars will not come.

The Department of Energy should poll the industry prior to the passage of any legislation to determine the adequate minimum timeframe to encourage private investment.

Coordinated Permitting Process. Given the economic transformation of NW Colorado in the past 20 years, coupled with the increasing level of natural gas development, a coordinated and integrated permitting process is essential. The environmental and land use permitting process can be complex and time-consuming when all the local, state and federal requirements are considered. Coordinating the process is essential, and cannot be underestimated. For the requirements in place 20 years ago, the average timeframe to permit an oil shale project was about 42 months. Some processes have become more complex since then—and certainly public interest is more organized and focused.

As a reminder, the Colorado Joint Review process grew out of the concerns raised over the concept of the Energy Mobilization Board. That Board would have had the power to preempt local and state regulatory requirements in the national interest. The reaction in the West was to coordinate and streamline, not dismantle, the existing process. And it worked. Attempts in recent years to truncate the process have been met with public criticism and lawsuits. Such efforts have proven to be counterproductive to the goal of developing these important resources.

The Colorado Joint Review Process is an option that the federal government should consider fully funding, or partially funding along with industry, to assure a rigorous review with adequate public input and consultation.

Economic Impact Analysis. Once the development area is determined, a procedure must be established to evaluate economic impacts at the local level. The federal government should fund, either through the bonus bid process or authorizing legislation, a concept similar to the tools used by the Cumulative Impacts Task Force. This analysis would not only guide the timing of needed permanent and temporary community services and infrastructure, but also allow local governments to establish fiscal tools that would insure that growth could pay its own way.

The true cost of the development of strategic resources such as oil shale must be evaluated not only in the context of their technology and development costs, but also the costs and benefits to the community. Securing a safety net is the primary lesson of the last bust.

Conclusion

It is essential that Congress consider the life cycle of oil shale development as it contemplates a renewed national oil shale effort. Only this view will portray the complete picture, so that the appropriate technology, environmental and economic structures can be defined and funded for a successful long-term effort. I look forward to working with you in the months ahead.

APPENDIX A

A Local Government Perspective on Federal Oil Shale Research and Development Efforts

Mr. Chairman and Members of the Committee:

My name is Jim Evans, Executive Director of the Associated Governments of Northwest Colorado (AGNC), representing cities and counties in the 5-county region of Garfield, Mesa, Moffat, Rio Blanco and Routt Counties in Northwest Colorado. On behalf of our local governments I want to express our appreciation to your committee for asking our local government views on the development of oil shale technology.

Our local government association was formed at the start of the last oil shale development cycle as the "Regional Oil Shale Planning Commission" with the specific charge to address the socioeconomic and environmental impacts of a potential commercial scale oil shale industry. Now, renamed as the Associated Governments of Northwest Colorado, we are still concerned with this issue. This time around it appears that our region will need to address the potential growth and infrastructure impacts of oil shale development on top of the socioeconomic impacts already occurring in our region from record levels of natural gas, oil and coal production. With estimates of from 600 billion barrels to 1.8 trillion barrels of recoverable oil from shale in our region, we recognize the national interest in developing the technology for this resource. In particular, the needs identified for the Department of Defense for a secure domestic source of fuel make us realize that the importance of the resource cannot be ignored. We also understand the potential economic benefit development of this resource can play on our national balance-of-trade and G.N.P.

Since more than 80% of the oil shale resource is located on federally-owned public land and recognizing that the future development is driven by national interests, local governments in our region believe the federal government must play a lead role in addressing these socioeconomic and environmental impacts and costs. We do not want to see local governments (and local taxpayers) stuck with the costs of new infrastructure and the mitigation of environmental impacts. So we are pleased to see that your Committee and the Department of Energy as we begin this next cycle in Oil Shale development are addressing these issues up front. This is a refreshing difference than the start of the last cycle. Back then, with an oil embargo facing the country, Congress first responded with a proposal for an Energy Mobilization Board with the power to declare Northwest Colorado as a "National Sacrifice Zone". Fortunately, that proposal did not make it all the way through Congress and as my

following testimony indicates, we learned a lot during a fairly painful 18-year boom/bust cycle prematurely attempting to develop commercial scale projects.

This time we appreciate the "Research and Development" type approach being put forward by the Department of Energy, and by the recognition of your Committee up front that you are looking for development of an environmentally friendly technology, and an approach not dependent upon the price of oil.

Because we support your stated approach it gives me the opportunity to say,

"I am from the Local Government, and I am here to help you."

I would like to start my help by submitting for the record the following resolution from Club 20, the community based Colorado organization representing cities, counties, businesses and citizens throughout Western Colorado. This resolution was unanimously adopted by the Club 20 Board of Directors endorsing a Research & Development program as being considered by your Committee.

Club 20 Support for an Economically Viable And Environmentally Sound Oil Shale R & D Program

Whereas Oil shale may still be the largest untapped resource available for transportation fuels;

Whereas the richest deposits of oil shale in the world are located in Northwestern Colorado and Eastern Utah;

Whereas a DOE report indicates that oil shale development may still be important for our country's National Security (as an alternative to imported oil) and for our Economic Security (to improve our balance of trade); and

Whereas without a well conceived federal R & D program this region may again someday be faced with another crisis oriented commercial scale oil shale program.

Now therefore be it resolved that Club 20 supports research and development efforts leading to an economically viable and environmentally sound oil shale program.

Further, Club 20 supports DOI/DOE/DOD efforts to develop a national oil shale policy and long-term R & D plans.

APPROVED, FEB. 15, 2005
CLUB 20 ENERGY COMMITTEE
CLUB 20 NATURAL RESOURCES COMMITTEE
APPROVED, APRIL 1, 2005
CLUB 20 BOARD OF DIRECTORS

Background: Last Oil Shale Development Cycle 1974-1992

- The last oil shale cycle started with the Arab Oil Embargo in 1974. This was a Sudden Oil Shortage, resulting in long lines at gas pumps, temporary high gas prices, and a staggering impact on the U.S. Auto Industry and U.S. economy, aggravated by gasoline rationing.
- Congress responded in a crisis mode.
- The first industry proposal to local government was: Get out of the way and we will develop Oil Shale! Congress responded with a Proposal for Northwest Colorado to be declared a "National Sacrifice Area", including an Energy Mobilization Board with power to override Federal, State and Local environmental and land use laws. State and Local governments responded on an adversarial basis.
- President Jimmy Carter instead got Congress to establish the Synfuels Corp. with $15 Billion in price guarantees and price incentives.
- In our region 12 projects were underway at peak of cycle (either in planning, permitting or construction).
- An Exxon White Paper suggested a socioeconomic impact of a one-million population increase in NW Colorado by 1990. It appeared that all the construction workers in USA would be required for the effort if all the companies went forward at the same time.
- The Colorado projects reaching construction or testing: Exxon Colony Project, Unocal, Oxy (CB), CA consortium. The DOE Anvil Points facility in the meantime was pretty much abandoned, except for a look at an asphalt additive byproduct.
- The cycle collapse (Bust) started May 2, 1982 with an abrupt Exxon Colony closure. In the Boomtown Blues book, this event was blamed for the U.S. and worldwide recession.
- The Unocal project & Oxy continued their efforts through 1990-92. This somewhat mitigated the "bust" cycle. At the peak of the cycle, the combined population of the 2 most impacted counties (Garfield and Mesa) increased from 1981

to 1983 by 12%, from 112.0 thousand to 125.6 thousand. Then in the next 2 years the combined population dropped back to 111.8 thousand.

- Congress then overreacted and shut down virtually all oil shale research programs, despite recommendations from many sources that research and development activities should continue.

Was Anything Learned During This Cycle? Yes!

- Congress in 1975-76 enacted Mineral Leasing Act Amendments at the urging of States and Local Governments. The State share of federal royalties increased from 37 1/2% to 50% with priority for local governments impacted by Mineral Leasing activities, such as Oil Shale, Oil, Natural Gas and Coal.
- Congress enacted Payments-In-Lieu of Taxes (PILT) Act to compensate counties for tax exempt federal land thereby giving direct assistance to rural public land counties.
- States in turn enacted Severance Taxes, also with a priority to address socioeconomic impacts.
- Local governments in turn enacted Major Impact Land Use Mitigation Ordinances.
- The Colorado Joint Review Process (CJRP) was initiated. This was a voluntary program designed to coordinate and speed up federal, state and local permitting.
- Local Government Energy Impact Programs were established by States with the new Revenue from Mineral Leasing and Severance Taxes. These programs today address the ongoing impacts of mineral development. The Energy Impact Program in Colorado actually started with the formation of the Regional Oil Shale Planning Commission (now AGNC) and the enactment of the Oil Shale Trust Fund (OSTF). From the OSTF $75 million plus interest was allocated to NW Colorado counties. The $75 million was Colorado's 37.5% of federal Oil Shale leasing bonuses.
- Negative impacts of the abrupt Exxon Colony Project closure actually resulted in a positive turnaround on State/Local/Industry relationships and communications as Unocal and Oxy proceeded with their projects with local support.
- Local governments also supported continuation of the Unocal and Oxy projects, including proposals to turn them into federal oil shale technology demonstration projects.
- Support for a Federal Oil Shale R & D program was generated in Colorado, Utah, Wyoming, Kentucky, Illinois and California, but to no avail.
- New Paraho Corp. temporarily continued oil shale asphalt testing at Anvil Points to demonstrate the byproduct approach to make oil shale economically viable. Some of the asphalt test strips are still in place with no repairs required.

Local Government Advice to Industry for the Next Oil Shale Development Cycle: Communicate! Communicate! Communicate!

The Shell Oil Shale Project is on the right track. Shell Oil is the only company in Colorado who is currently continuing with field-testing. Local governments appreciate these efforts. Their efforts have included ongoing meetings with County Commissioners, Cities, school districts and citizen groups. They have sponsored and organized town meetings. These were very successful from a local perspective. These should continue at the beginning of each phase of an R & D program.

The Department of Energy also appears to be on the right track. The Naval Petroleum and Oil Shale Reserve Office of DOE has prepared a well documented and thorough report indicating the National interest in developing the oil shale resource (trade deficit impact on the economy and national defense interest in a secure oil source.) We believe addressing the socioeconomic and environmental issues in the DOE proposal for a National R & D program and demonstration facility is on target. Virtually all groups and industry involved in the last oil shale cycle have recommended the need for an ongoing federal oil shale research program.

These Groups and individuals back in 1991 were: The Rocky Mountain Oil & Gas Association, The Western Oil Shale Action Committee, Club 20, Associated Governments of Northwest Colorado, The Garfield County Citizen Alliance, Governor Roy Romer, Senator Tim Wirth, Representative Ben Campbell, The Rebuild America Foundation, The Alternate Energy Research Institute, and The Rocky Mountain Institute. There may have been others. These were the ones that I was aware of.

Recommendation to Address the Socioeconomic Impacts of the Next Oil Shale Cycle

With the renewed interest in oil shale development, the Department of Energy needs to provide funding for socioeconomic programs to:

- Assemble and update impact data from the last cycle.

- Identify appropriate computer systems/models to assess projected impacts.
- Development of baseline economic data for current activities.
- Help identify and provide revenue streams for local/state government services/ infrastructure potentially impacted by oil shale development.

DOE also needs to identify and recommend appropriate federal, state and local policies to encourage prudent and environmentally sound oil shale development.

Recommendation to Address Environmental Impacts of Oil Shale Development

The DOE Demonstration program/projects should address:

- Surface disturbance impacts and ongoing reclamation requirements.
- Air Quality impacts.
- Water Quality and Quantity impacts.
- Wildlife protection and mitigation requirements.
- Employee health, safety and training needs.

Regular communications with news media and environmental groups should address the potential environmental impacts of various oil shale technologies.

The Colorado Department of Public Health and Environment should be actively involved in monitoring air quality and water quality impacts.

The State of Colorado Department of Natural Resources and its Wildlife Division should be actively involved in these reclamation and wildlife issues.

The Department of Interior should develop a leasing program to accommodate access to oil shale for research and demonstration project purposes. Any commercial scale leasing proposals must include provisions that recognize the "carrying capacity" concepts for socioeconomics and the environment that are part of the BLM Piceance Basin Resource Management Plan.

Recommendation to Provide the Funding for Oil Shale Research Costs and Incentives

We believe it is fortunate that Congress may have already provided a potential source of funding for Oil Shale R & D efforts. This revenue may be currently available from the Naval Oil Shale Reserve (NOSR) lands themselves located in Northwest Colorado. As indicated in the attached letter from the Department of Interior, some $43.7 million may be accumulated by March 2007 in a U.S. Treasury account from the current natural gas leases on their NOSR lands. These NOSR lands were transferred by Congress from DOE to the Department of Interior with a Congressional priority established for natural gas leasing.

Some of these funds, estimated at $5.8 million, are earmarked for environmental cleanup of the Anvil Points spent shale pile. Otherwise, we believe Congress has the opportunity for the remainder of these funds to be made available to address the socioeconomic and environmental aspects of oil shale development in Northwest Colorado.

In the future, more revenue should be available from this source. According to industry estimates, additional leasing of the NOSR lands could produce leasing bonuses of up to $360 million (to be shared 50% federal and 50% state) plus ongoing production leases of an estimated $32 million annually for at least 20 years. That would be another $640 million total also to be split 50/50 federal and state. Congress should establish a priority to address oil shale and other energy development impacts in Northwest Colorado from these leasing revenues.

We believe this type of funding is necessary to make sure the DOE research and demonstration projects can proceed without interruptions from fluctuations in the price of oil.

Thank you for this opportunity to testify. I would be happy to answer any questions you may have.

JIM EVANS, AGNC EXECUTIVE DIRECTOR

Response to questions submitted for the record by Russell George, Executive Director, Colorado Department of Natural Resources

We appreciate the State of Colorado's position, as stated in your testimony, that through the production of oil shale and other resources our Nation can become energy independent in our lifetime. We thank Colorado for its commitment to support production of the vast oil shale resources within its boundaries. We agree with you that this must be done in a responsible manner and we look forward to the Federal Government working closely with the western oil shale States as we move to produce this vast resource for the American people.

1. What is the source of funds that the Congress should look to in order to provide the financial resources to compensate for socioeconomic and environmental impacts?

Lease Bid Bonus Payments collected and distributed in advance are the most effective tool for the front-end financing of socio-economic impacts. As production develops, federal royalties and state severance taxes can also reimburse local communities for such impacts. This model worked in the 1970's/1980's, and should still be effective. This approach is validated in the testimony provided by the Associated Governments of Northwest Colorado.

Environmental impacts are the responsibility of the permittee, and are embodied in the stipulations of the necessary federal, state and local permits required for such a project to proceed. For this reason, the existing public permitting processes should not be short-circuited to expedite production. Their timeframes allow for adequate public review and comment, as well as the regulatory tools to mitigate impacts.

2. Given the fact that all resource development is contingent upon the economics of production, which is primarily derived from the price the product can command and the costs of production, what can the Federal Government do to ensure that oil shale production is economical?

The State of Colorado is not convinced that it is the role of the federal government to make oil shale production economical. The economics of alternative fuels, like oil shale, are ultimately set in the international marketplace. However, it is an appropriate role of the federal government to support technology development, that can be done in three ways. First, through the development of oil shale technologies at federal facilities—such as the national laboratories. They played such a role in the 1970's/1980's effort. Second, the federal government can make federal lands and facilities available to the private sector to test oil shale technologies. All NEPA requirements would prevail. Finally, the federal government could make technology development grants available for private technology development projects. All these actions would in effect subsidize the cost of technology development, and ultimately the cost of the product.

3. What policies of the State of Colorado will ensure that the local governments receive their fair share of the State's one-half of Federal royalties and the State severance tax on the production of Federal oil shale?

The appropriate state statutes guiding federal royalty distributions and state severance tax distributions have been in place since the 1970's. There is no need for modification at this time.

4. How do you recommend that coordination with the State and local governments on leasing and production be handled?

It is the intention of the Department of Natural Resources to seek reauthorization of the Colorado Joint Review Process in the 2006 legislative session. That process was developed in the 1970's partially in response to the oil shale boom. It creates a forum for public participation in the scoping of federal leasing and NEPA documents, as well as coordinated public review and comment in the federal, state and local permitting process. The core funding would come from the state severance tax fund. The federal participation will be funded through the relevant federal agencies, and the project proponents would fund the costs of the process specific to their project. Regulatory oversight under existing federal, state and local laws will guide the production and reclamation phases.

5. What mechanisms should be put in place for engaging communities in federal planning and program development? For example, would Memoranda of Understanding with Regional Planning councils be of value?

As outlined in Question 4, the principal state process will be the Colorado Joint Review Process for leasing and permitting decisions at the federal, state, and local level. Local governments will coordinate the socio-economic impact analysis using funds distributed through the Bonus Lease Bid Process. There are no regional planning councils in Colorado. Their equivalent would be councils of government which may not have energy impacts within their purview. Therefore, the distribution of Bonus Lease Bid Funds as guided by state statute would ensure that the affected local governments would have access to the appropriate funds.

6. We have heard proposals to direct mineral lease royalties from the Naval Oil Shale Reserves in Colorado to the planning and impact mitigation efforts of Colorado, Utah and Wyoming. Would Colorado support this proposal?

Assisting in local and regional impact planning and mitigation efforts is something Colorado has always supported. In the short-term Colorado would support

using royalties from NOSR 1 and 3 for these purposes both here and in neighboring states, until such time the federal government is fully reimbursed for the infrastructure costs and environmental restoration work that was required as part of the transfer legislation. At that point, and we understand the full $43 million will be realized in 2007, it would be necessary to resume the normal state share royalty distribution formula for federal minerals produced in NOSR 1 and 3.

7. Oil shale may provide long-term energy security for the US. Would Colorado support program planning and managing of this resource as a Petroleum Reserve?

Yes, as long as the management of such a reserve would be subject to adequate public participation including opportunities for public review and comment. Oil shale country in Colorado is also the site of competing resource development (coal, oil and gas), and competing land uses (recreation, agriculture, and mineral and energy development). This is the basis for Colorado's request that the federal government identify those areas suitable for oil shale development in light of competing land uses. The competing uses, as well as community needs, are the basis for a Colorado Joint Review Process to allow adequate public input on complex issues such as a Petroleum Reserve.

Mr. GIBBONS. Thank you very much. And we certainly appreciate the State of Colorado's position on this and your commitment and support for developing this, as well.

We turn now to Mr. Michael McKee. Commissioner, welcome. We are happy to have you. I know it is a long way from Uintah County, Utah, here to be with us, and we certainly appreciate that. Welcome. The floor is yours.

STATEMENT OF MICHAEL J. McKEE, COMMISSIONER, UINTAH COUNTY, UTAH

Mr. MCKEE. Thank you, Mr. Chairman, and Committee members and staff members. And greetings from Uintah County, Vernal, Utah—Utah, dinosaur land.

As has been brought out, there are vast energy resources in our area; including oil and gas, gilsonite, coal, tar sands, and oil shale. This past year, the Vernal BLM field office was the second-busiest field office in the United States, processing approximately 700 APDs, or Approved Permits To Drill. This past month, they processed over 100. So they're clicking right along.

Moving to oil shale real quickly, a significant portion of the oil shale resources of the Green River formation are located in Uintah County, Utah. These resources are believed to be the most concentrated accumulations of hydrocarbons on Earth.

The commercial attractiveness of these zones measure from 50,000 barrels per acre to more than 1 million barrels per acre. This formation contains, and depending on testimony this morning, which numbers you look at, somewhere between 1 and 3 million barrels per acre. That could equate to 2 to 3 trillion barrels of oil. And as has been mentioned, that's many more times than the total reserves located in the Mideast.

In addition to oil shale, there are billions of barrels of tar sands of oil in our area. The issues in regard to development of tar sands mirror in many ways those of oil shale. We're speaking primarily of oil shale here today, but we have abundance of resource of both commodities.

The majority of these resources are located on Federal lands managed by the BLM. The remaining resources are located on that

of the state and of private companies, individuals, and Indian tribes.

In the '70s and '80s, there was considerable interest in the development of oil shale. Driven by gas shortages of the '70s, the government, along with industry, put considerable resources into development of an oil shale facility in Uintah County, Utah. Local interest in oil shale development did not decline when that of the general government and industry did.

One company, in particular, has conducted resource and development activity since 1993. The results are the development of a working retort that processes oil shale. This facility is currently attempting to obtain adequate feed stock to run their retort to enable an independent certification of its operation.

Uintah County fully supports the development of oil shale and tar sands. And one of the main points we would make is the mistakes of the past should not be repeated. The President and Department of Energy have determined that increasing liquid fuel supply from domestic sources is an important national objective. Clearly, there's no greater opportunity to achieve this goal than the development of the Nation's oil shale resources.

Some of the benefits that would come from that, as we're aware, is it would bring the balance of trade closer in line; reduce the competition for energy resources with Third World countries and developing nations; stabilize American industry with a more dependable fuel source; and provide the military with a source of fuel. Numerous byproducts could be produced.

We believe that there is immediate need for action. We believe that government must play a critical role in removing impediments to the development. I'm going to list several suggestions, though this is in the testimony:

Authorize and direct the BLM to develop a commercial Federal oil shale leasing program;

It's been mentioned here this morning, but to repeal or modify the Mineral Leasing Act that currently restricts oil shale leases to one lease per company and a maximum 5,120 acres per lease, which of course is eight sections;

Authorize and direct the BLM to exchange Federal lands for public or private lands, where appropriate, to facilitate development of the resources;

Direct all of the Federal agencies to refrain from management practices that restrict access to resource and prevent the development of these resources, including the water resources;

Authorize and direct the Department of Energy, in cooperation with the BLM, to access and make available the existing White River Mine, which was mentioned here earlier this morning, and facilities, as well as oil shale stockpiles for use by industry;

This next point is a very important point to us in local government. Authorize the one-third of the total oil shale and tar sand royalties to come back to the county of origin. This funding would assist in mitigation of developing and maintaining social and economic impacts created with all energy-related development production;

All forms of transportation will be necessary;

We are suggesting that at task force be created consisting of Federal, state, and local government officials. Authorize this task force to utilize expertise of industry, scientific, and collegiate academia. Uintah County has considerable expertise and experience, and we would like to be part of this resolution.

We would also like to, just as has been mentioned earlier here this morning, make an invitation to all members or any members of this Committee or this Subcommittee or members of the Resource Committee, to come out to our area and see what we have out there. We would certainly host you. We would be happy for you to come. And thank you for the opportunity to be here.

I might also just mention we provided a little bowl that has some tar sands. That came from a mountain, or a hill about a couple of miles just west of Vernal. And there are mountains of these tar sands in our area.

This also is a piece of oil shale that came from the White River Mine. If you were to break this oil shale open and were to smell it, it would smell a little bit like diesel. But essentially, it's algae.

Thank you very much.

[The prepared statement of Mr. McKee follows:]

Statement of Michael J. McKee, Commissioner, Uintah County, Utah

OIL SHALE & TAR SANDS, UINTAH COUNTY, UTAH

I. A BRIEF HISTORY

In the '70s and '80s, there was considerable interest in the development of oil shale. Driven by the gas shortage of the 70s the government, along with industry, put considerable resources into the development of an oil shale facility in Uintah County.

The decline in crude oil prices in the 80s resulted in the loss of government support for oil shale research and development, and subsequent termination of industry interest.

All that remains of this effort is the White River Oil Shale Mine and associated facilities in declining condition and oil shale stock piles.

II. WHERE WE ARE TODAY

A major portion of the oil shale resources of the Green River Formation are located in Uintah County. These resources are believed to be the most concentrated accumulation of hydrocarbons on earth. The commercially attractive zones measure from 50,000 barrels per acre to more than 1 million barrels per acre. The richness of these zones are well known.

The majority of these resources are located on federal land managed by the BLM. The remaining resources are owned by the state of Utah, individuals, private companies, and Indian tribes.

Because of the amount of resources existing under the federal lands, BLM resource management on these lands will greatly affect their development.

Local interest in oil shale development did not decline when that of the general government and industry did. One company, in particular, has conducted resource and development activities since 1993. The results are the development of a working retort that processes oil shale. This facility is currently attempting to obtain adequate feed stock to run their retort to enable an independent certification of its operation.

Uintah County fully supports the development of oil shale and is very concerned that the mistakes made in past efforts should not be repeated. Specifically, the lack of comprehensive and coordinate planning, impacts on community development and local infrastructure were not properly planned for or funding needs considered.

III. POSSIBLE BENEFITS

The President and the Department of Energy have determined that increasing liquid fuel supply from domestic sources is an important national objective. Clearly, there is no greater opportunity to achieve this goal than the development of the nation's oil shale resources.

The Green River formation located in our area contains three trillion tons of oil shale, which is 2-3 times more than the reserves located in Saudi Arabia.

If these resources are developed, the United States could greatly reduce, and with conservation efforts, eliminate our dependency on imported oil and help reduce the balance of trade.

Uintah County, the intermountain area, and the nation would benefit from oil shale development. As this development occurs, the following goals could be accomplished:

- Keep the social and economic benefits of the $20 billion per month spent on imported oil and spend it on development in the United States.
- Depending on the method used, there are numerous by-products that could be produced.
- Provide the military with a long term and secure source of fuel.
- Stabilize American industry by having a more dependable fuel source.
- Reduce global conflicts related to energy access.
- Reduce the competition for energy resources with third world countries and developing nations.

IV. TAR SANDS DEVELOPMENT

In addition to oil shale Uintah County has considerable tar sands resources. There are billions of barrels of oil in the tar sands in our area. The issues in regards to the development of tar sands in Uintah County mirror those for oil shale.

Uintah County supports the development of tar sands, however, most of the comments in this document are on oil shale.

V. NEED FOR ACTION

Government must play a critical role in removing impediments to developments, and neutralizing and mitigating investment risk.

Policies, regulations and legislation are needed to make these resources available on terms attractive to industry while ensuring efficient resource development and equitable economic returns on investments.

- Authorize and direct the BLM to develop a commercial Federal Oil Shale Leasing Program with the goal of initiating leasing by December 31, 2006.
- Repeal or modify the Mineral Leasing Act that currently restricts oil shale leases to one (1) lease per company and a maximum of 5,120 acres per lease.
- Authorize and direct BLM to exchange Federal lands for public or private lands where appropriate to facilitate development of the resource.
- Direct all affected Federal Agencies within the confines of existing law, to refrain from management practices that restricts access to the resource and prevents the development of water resources needed for production and support infrastructure.
- Authorize and direct the Department of Energy (DOE), in cooperation with BLM, to access and make available the existing White River Mine and facilities, as well as, oil shale stock piles for use by industry to support demonstration and commercialization of oil shale technologies.
- Authorize the return of 1/3 of the total oil shale and tar sand royalties to the county of origin. This funding would assist in mitigation of developing and maintaining social and economic impacts created with all energy related development and production.
- All forms of transportation, including rights-of-way, roads, pipelines and other means, are necessary to the success of oil shale development. There are immediate needs for transportation improvements during the research and development phase. Once production starts there will be a need to transport the materials out. It is imperative to have cooperation between Federal and State land holders to allow access.
- Existing delays in energy related development and production permit approvals must be resolved to insure this problem doesn't carry over into the processing of oil shale leasing. Create a task force consisting of Federal, State and Local government officials. Authorize this task force to utilize expertise of industry, scientific and collegiate academia. Uintah County has considerable experience and has access to expertise related to this issue and would like to be part of the resolution.
- Impacts to other resources such as wildlife, grazing, soil and water must be offset by improvement in existing habitats and/or carefully planned mitigation of impacts.

Mitigating Investment Risks

Oil shale production is characterized by high capital and operating costs and long periods of time between expenditure of capital funds and the realization of

production revenues. For "first-generation" facilities there is substantial uncertainty over the magnitude of capital and operating cost. Revenue uncertainty is imposed by not knowing future market prices. These and other uncertainties pose investment risks that currently make oil shale investment less attractive than other investment options.

Public policy and legislation can lower investment risk by reducing cost and revenue uncertainties and by sharing in the financial risks. Public action is warranted when pursuing public goals of secure domestic fuel supplies and enhanced business and economic activity. The most effective of these actions include:

Demonstration Projects. A cost-shared oil shale demonstration program would:

- Accelerate the timetable to the all-important first-generation commercial production by helping to remove cost uncertainty,
- Broaden the base of investment interest among intermediate and independent producers that could not carry the development risks alone, and
- Serve as evidence of the public's commitment to this resource.

Market Assurance: Authorize and direct the Department of Defense to specify and qualify shale oil derived aviation turbine fuels and to enter into purchase agreements at a guaranteed minimum and maximum price. This will serve to minimize market-acceptance risk and price-volatility risk.

Production Tax Credit: A production tax credit, indexed to inflation and capped or phased out at a ceiling price per barrel will enable oil shale to directly compete with foreign conventional oil. This could be accomplished by amending current "Section 29" tax credits for non-conventional fuels or through a new provision crafted for oil shale.

Federal Royalty Relief: Federal royalty structure is not yet defined for oil shale extraction. Providing royalty relief in the research and development stages will significantly improve project economics. A fair return to the Federal government can be achieved by graduated royalty rates in later years, after investment payback.

Accelerated Depreciation: Allowing front end capital investments to be depreciated in a shorter time than is allowed under current law could improve cash flow and could stimulate investment by enabling earlier payback. Royalty holidays and expended depreciation are credited as the two most important fiscal measures stimulating the production growth of Alberta oil sands.

Investment Tax Credit: Congress should allow an investment tax credit similar to that which is proposed for coal-to-liquids projects to reduce up-front capital costs and accelerate payback.

Depletion Allowance: Congress should allow oil shale projects to qualify for a percentage depletion allowance (similar to that for oil and gas resource extraction). This latter provision helps provide parity for private resource holders relative to the royalty holidays afforded federal lessees.

Community Development and Infrastructure Support

Oil shale industry development and operation will cause significant population growth in the local communities, accompanied by requirements for investment in community infrastructure, such as roads, schools, hospitals, and other support services. Uintah County is a water short area. Adequate water supplies must be developed for both domestic and industrial use.

Costs for engaging in the federal planning process and for planning and construction of infrastructure occur long before tax and royalty revenues are received from oil shale operations and associated economic activity. Development delays or industry failure pose additional risks to local communities. Planning must include a strategy to avoid boom/bust cycles in local economy.

To minimize the severity of impacts and mitigate the financial risks the following action is recommended:

- Authorize and direct the DOE, in cooperation with DOI and DOD, to develop a well-conceived federal Oil Shale Program so as to avoid a crisis-oriented response,
- Communicate with stakeholders to identify issues of concern and take measures to mitigate those concerns,
- Provide advance financial support for the communities and States to facilitate their engagement in the program development process and to mitigate cost burdens that occur before tax and royalty revenues are realized.

Streamline Regulatory Permitting

Environmental impacts must be effectively mitigated through best-available resource technologies and rigorous management utilizing adaptable and goal oriented management, not exclusionary management that is not practiced. Control of air emissions, water effluents, leachates from spent shale disposal, land reclamation

design, and other environmental issues will need to meet published regulatory standards.

- Complying with these standards will require complete and comprehensive applications which should receive prompt review and action.
- Consistent with Executive Order 13212 "Actions to Expedite Energy Related Projects", it is recommended that the Interagency Task Force be reconvened and directed to coordinate with the EPA and state regulatory agencies and to review Federal environmental requirements that impact oil shale development and identify areas where permitting can be streamlined to achieve national energy goals. To date, the provisions of this executive order have not been implemented at the field office level or reflected in the recent resource plan.

Government/Industry Coordination

- Development and implementation of a well-considered and coordinated Oil Shale Program Plan requires goal-oriented management in government. To complement the short-term insurance policy provided by the Strategic Petroleum Reserve Congress should authorize and direct the Secretary of Energy to establish an Office of Strategic Fuels within the DOE Petroleum Reserves.
- The mission of this Office is to promote fuels security for the United States, provide the analytical basis for strategic fuels planning, oil shale program development and management, establish and administer functions of an interagency government/industry oil shale task force and manage outreach and education efforts related to Federal oil shale efforts. The charter for this office should include interaction with the Departments of Defense, Interior, and Treasury.
- Congress should authorize and direct DOE to establish a Federal Oil Shale Task Force, to include representatives from DOE, DOD, DOI, and the Department of Treasury, technical experts, and advisors from industry, impacted states and communities, and other stakeholders to coordinate and facilitate oil shale industry development efforts in an integrated fashion.

VI. PROPOSED OIL SHALE, RESEARCH, DEVELOPMENT AND DOCUMENTATION (RD&D) PROGRAM

In the supplementary information provided in the RD&D Program draft, it says that BLM intends to ensure that states and local communities have the opportunity to be involved in the development of a commercial program. Uintah County would like to see this involvement extended to include all NEPA and mitigation and mitigation issues associated with both RD&D and commercial development.

In earlier comments Uintah County expressed concern regarding the adequacy of 40 acres to conduct RD&D operations. In the latest draft the 40 acres has been changed to 160 acres. The County's recommendation remains 640 acres.

BLM considers 160 acres adequate to accommodate an R&P activity that can be envisioned. The County proposed 640 acres so as not to limit the type of R&D that can be located on the site. Perhaps 160 acres could be established as a limit unless the proponent can, based on development plans, justify additional acreage not to exceed 640 acres.

Response to questions submitted for the record by Michael J. McKee, Commissioner, Uintah County, Utah

1. *What are the most important things that the Federal Government can do to ensure that production of large quantities of oil from oil shale happens in a timely manner and under appropriate conditions?*

Response: There are several ways to ensure production of large quantities of oil from oil shale in a timely and appropriate manner. They are:

- Develop a national policy and strategic plans that recognizes oil shale development as a way to reduce our dependence on imported oil that provides for it's development in a coordinated manner and fully involving local governments and in recognition of the impacts of the development on them.
- Establish regulation for the commercial development of oil shale and expedite access to oil shale resources.
- Structure royalties and provide tax incentives that will allow lessee to accelerate recoupment of investment so as to encourage rapid development.
- Use planning method similar to that used by the National Petroleum Reserve to provide orderly and coordinate planning that will insure impacts to local communities are addressed and that infrastructure needs are well planned and such projects are in place prior to onset of development. There is a need to implement the planning process now.

2. *We note Uintah County's full support of oil shale development. Does the State of Utah have policies in place that you feel will provide Uintah County with it's appropriate share of revenues, including royalties and severance taxes, that will be derived from oil shale production? Do you feel that counties in which production is located should receive a direct portion of the royalties and bonus bids?*

Response: Utah does have policies in place for revenue sharing. However, political demographics prevent the counties of origin from receiving a proper share that adequately reflects impacts to infrastructure and governmental services. While County's such as Uintah create the majority of the mineral revenues for the State of Utah the portion of revenues return to the County is not reflective of that contribution. Uintah County strongly supports counties of origin receiving directly portions of revenues from development of natural resources on public lands within their jurisdiction. In previous testimony Uintah County has supported the return of 1/3 (one third) of total royalties generated and bonus receipts to the county of origin to offset cost of increased services, development of and improvements to infrastructure and impacts to the community.

3. *Should the State of Utah, and it's counties, set up a joint process with the BLM to coordinate and speed leasing and permitting decisions?*

Response: Yes. Uintah County has considerable expertise in this issue and has for some time been active in leasing and permitting process on federal land through cooperation and coordination of NEPA processes and by facilitating dialog on current leasing and permits back logs and addressing the issues of uncertainty in the lease and permitting process. The County has actively sought additional funds to provide adequate staffing in the local BLM office.

The funding and staffing needed for a county to participate in these activities has put a burden on county resources which with the onset of oil shale development are sure to increase. Compensation for increases in governmental service associated with the increase in activity will help leasing and permitting decisions. It is imperative that the Bureau of Land Management office is funded adequately for such activities.

4. *What can the federal government do to ensure that local communities have the up-front financial resources needed to plan for development and mitigate impacts? Is there an immediate need?*

Response: Uintah County recognizes the immediate need for up front cost for planning and development and to mitigate impact. The County is supportive of the suggestions made by Jim Evans (in Russ George's testimony to the Senate Energy Subcommittee) that allocates current royalties produced from NOSR lands to this effort. We also feel that an additional portion of mineral lease revenue (now expanding because of regional gas production) could be allocated to the Counties of Origin.

The use of these funds provides immediate access to needed funds and would be recouped by increased revenue from oil shale development.

Mr. GIBBONS. Mr. McKee, thank you very much for your testimony. Thank you for the visual aides that you provided, as well. Thank you for your suggestions about how we should work together in incorporating the stakeholders, local government, county governments, as well.

And again, Mr. George, your requests certainly are agreed upon, that we need to approach this with the full understanding that we have to do it sensibly and correctly, considering the environmental concerns that we all have in this certainly.

We have two votes that have been called. We have about ten minutes or less remaining. I am going to turn questions over to our two panelists here, so that we might be able to wrap this up; because when we go to vote, who knows when we will get back. I don't want to hold you and this hearing open.

Mrs. Drake, do you have any questions?

Mrs. DRAKE. Thank you. And I will be real quick, because I am sure we will submit other questions to you. Does this type of resource exist in China? I am sure you probably saw that article today about China doing an unsolicited bid to take over one of our

oil companies, an $18-1/2 billion bid. I think we are all concerned about China. But does this type of resource exist in China, that if this technology is developed here, maybe they would be able to meet their own needs there? It is completely off the subject, but it is a thing that hit my mind.

Mr. MCKEE. There are others that certainly would know the geology of this better than what I do. But I do know that the Green River formation located in eastern Utah, western Colorado, and southern Wyoming, is the best resource in the world, by far. And while there may be resources, and I'm sure there are, in many other parts of the world, we have the best resource.

Mrs. DRAKE. And I would assume both of you would agree that this is not a shaky industry or shaky research or a shaky resource for us to develop, like we heard earlier?

Mr. MCKEE. We believe that this actually is around the corner. We believe that, with some help, if we can remove some of these impediments—there may need to be some tax credits. It depends on how fast we want to move along with this, in my estimation. If we want to kind of just go along the way we're going, it's going to take longer. If we want to streamline the process, I believe with some tax credits and some things up front, that it will expedite and help this to happen in more rapid fashion than it will naturally.

Mrs. DRAKE. I would like to thank both of your states for being visionaries. Thank you.

Mr. GEORGE. May I respond to your last comment? Have I got just a minute to do that? I was born and raised in the shadow of oil shale in western Colorado. And growing up, we heard about "Boom-bust, oil shale will never happen." Oil shale has chemistry to it that matters for human uses. So it will become a source of hydrocarbons for a number of uses, as time occurs.

What Colorado would like to suggest is that we should not have stopped research and development with the last bust 20 years ago. We have made virtually no progress on the science and the technology in the last 20 years. What we don't think would be wise is for us to have our successors come back here in 20 years and say again what I have just said.

We need to get on with it. We can do it. We can see how to do it. Our friends to the north in Alberta have shown us a way. And we need to get on about doing it ourselves.

Mrs. DRAKE. Thank you very much.

Mr. GIBBONS. Thank you very much. And to our witnesses, both of you, I apologize for the fact that we do not control the schedule on the Floor. They vote when they want to vote and set those in accordance. And sometimes they interfere with the great work that we are doing on these committees.

Your testimony, your presence here today, has been absolutely very valuable. Let us hope that we on the Federal side when we develop our policies can work with the county governments, state governments, that have these resources within their borders, to formulate expedited processes with regard to permitting, etcetera, so that we do it uniformly; that we do it without a lot of delay and bureaucratic obfuscation, if you will; so that we can get to this resource that is so vitally critical to the economy of this country.

I do appreciate the fact that each of you have taken a great deal of your time to come here today. We will submit written questions that we would like to ask for each of the panels to respond to accordingly and report back their answers to us; probably within a ten-day timeframe, if you could.

With that, again, I want to thank each and every one of you; apologizing for the interruption of our hearing today with the votes on the Floor. And again, your testimony has been critical to a better understanding. This is part one of a two-part hearing series. And we certainly look forward to future information and, as I said, to a brighter future with an energy policy that takes in oil sands, oil shales, and heavy oil, and unconventional sources.

With that, this hearing is adjourned. Thank you very much.

Mr. GEORGE. Thank you, Mr. Chairman.

Mr. MCKEE. Thank you.

[Whereupon, at 11:45 a.m., the Subcommittee was adjourned.]

[Additional material submitted for the record follows:]

[A statement submitted for the record by the Department of Energy, Government of Alberta, Canada, follows:]

Statement submitted for the record by the Department of Energy, Government of Alberta, Canada, 14th Floor, North Petroleum Plaza, 9945 - 108th Street, Edmonton, Alberta Canada T2K 2G8, http://www.energy.gov.ab.ca/89.asp

The Government of Alberta, Canada, is pleased to provide this written submission on the Alberta Oil Sands to the U.S. Subcommittee on Energy and Mineral Resources.

Included herein is a brief overview of the Province of Alberta; our role in North American energy security; the extent of oil sands resources in Alberta including reserves based on currently available extraction technologies; the role the Government of Alberta plays in bringing these valuable resources to market; and, importantly, the direct effect this has had on increasing investment and production. Production of crude oil from Alberta's oil sands has the potential to close the U.S. energy gap.

The Province of Alberta

Albertans are a breed apart. They are driven by the pioneering spirit that first settled the land. They hold dear the ethics of hard work and personal responsibility. They cherish the ideals of family and community that built the province.

Our policies focus on free trade and competitive markets as the best way to allocate scarce resources. Provincial law prevents the government from subsidizing any commercial business entity. The Province has no sales tax, a 10% flat personal income tax, and no debt—something that has not been achieved anywhere else in Canada, and something of which Albertans are justifiably proud.

Year after year, Alberta's economic growth leads Canada, averaging 3.7% annually over the past 10 years. We lead the nation in job creation, and our unemployment rate is consistently among the lowest in Canada. Alberta's per capita disposable income and standard of living are the highest in Canada. Not surprisingly, we continue to experience the strongest population growth in Canada, with people from all over Canada and around the world migrating to our province to experience the Alberta Advantage for themselves and their families.

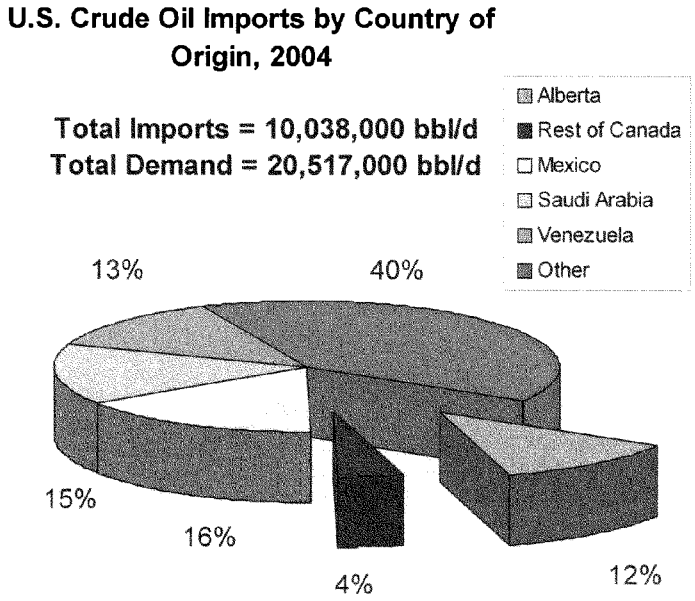
North American Energy Security

Alberta is rich in hydrocarbon resources—producing almost 1.7 million barrels per day of crude oil, and 13.8 billion cubic feet per day of natural gas.

Both Alberta and Canada are vital to the energy security of the United States—we are reliable, secure and, importantly, stable suppliers of energy to the US. In 2004, for the sixth year running, the U.S. Energy Information Administration recognized Canada as the largest supplier of oil (crude and refined) to the US.

Approximately 12% of U.S. crude oil imports and 11% of its natural gas consumption come from Alberta alone.

Figure 1: USA 2004 Crude Oil Imports by Country of Origin

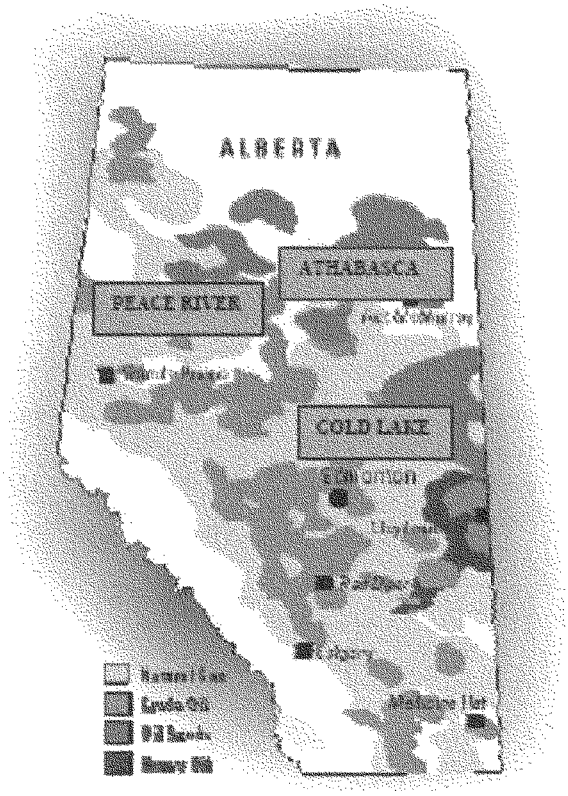


What are oil sands?

Oil sands are deposits of bitumen, a molasses-like viscous oil that requires heating or dilution with lighter hydrocarbons in order to flow. Second only to the Saudi Arabian reserves, Alberta's oil sands deposits have been described by Time Magazine as "Canada's greatest buried energy treasure," which "could satisfy the world's demand for petroleum for the next century."

Deposits are found in three major areas in northeastern Alberta: Peace River, Athabasca (Fort McMurray area), and Cold Lake (north of Lloydminster), totaling approximately 54,400 square miles—an area larger than the state of Florida.

Figure 2: Alberta Hydrocarbon Resources



Size of Alberta Oil Sands Reserves

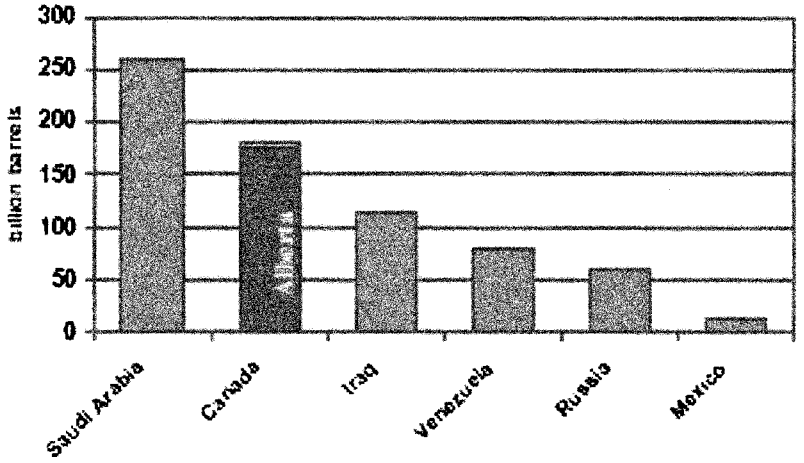
Alberta is home to the largest oil sands reserves in the world. Established reserves of 174.5 billion barrels are second only to Saudi Arabia reserves.

Established Reserves	174.5 billion barrels
Ultimate Potential Reserves	315 billion barrels
Initial In-Place Reserves	1.7 trillion barrels

This data is on the public record and confirmed by the Alberta Energy & Utilities Board (AEUB), an arms-length regulatory agency. Over 56,000 wells and 6,000 cores were the basis of the analysis.

Since December 2002, these figures were recognized by the Oil & Gas Journal, followed by the U.S. Energy Information Administration in 2003.

Figure 3: Proven World Reserves (Dec 2003)



Growth in Oil Sands Production

Oil sands raw bitumen production in Alberta averaged close to 1.1 million barrels a day in 2004 (about one-third of total Canadian production). By the end of this decade, we expect production to rise to 2 million barrels a day. See Appendix 1: Oil Sands potential: 3 million bpd by 2020, 5 million bpd by 2030.

Annual oil sands production is growing steadily by about 200-250 barrels per day (bbl/d) per year, as the industry matures. Output of marketable production increased to 962,000 bbl/d in 2004 from 853,000 bbl/d in 2003. It is anticipated that in 2005, Alberta's oil sands production may account for one-half of Canada's total crude output and 10 per cent of North American production.

Production Methods: Mining and In-Situ

There are two methods of oil sands production methods: mining and in-situ. Oil sands mining involves open pit operations. Oil sands are moved by trucks and shovels to a cleaning facility where the material is mixed with warm water to remove the bitumen from the sand. Today, all operating oil sands mines are linked with upgraders that convert the bitumen to synthetic crude oil.

For oil sands reservoirs too deep to support economic surface mining operations, some form of an in-situ or "in place" recovery is required to produce bitumen. In-situ oil sands production is similar to that of conventional oil production where oil is recovered through wells. Present operating costs, not including capital recovery, vary between $10-15/per barrel.

The AEUB estimates that 80% of the total bitumen ultimately recoverable will be with in-situ techniques. In general, the heavy, viscous nature of the bitumen means that it will not flow under normal conditions. Numerous in-situ technologies have been developed that apply thermal energy to heat the bitumen and allow it to flow to the well bore. These include thermal (steam) injection through vertical or horizontal wells such as cyclic steam stimulation (CSS), pressure cyclic steam drive (PCSD) and steam assisted gravity drainage (SAGD). Other technologies are emerging such as pulse technology, vapor recovery extraction (VAPEX) and toe-to-heel air injection (THAI).

In general, oil sands mines operations are found in central Athabasca deposits (around Fort McMurray). In-situ production is used in the Cold Lake, south Athabasca and Peace River deposits.

Government Framework

The mineral rights in approximately 97% of Alberta's 54,000 square miles of oil sands area are owned by the Government of Alberta (i.e., state-level) and managed by the Alberta Department of Energy. The remaining 3% of the oil sands mineral

rights in the province are held by the federal Government of Canada (i.e., federal-level) within First Nation reserves, by successors in title to the Hudson's Bay Company, by the national railway companies and by the descendents of original homesteaders through rights granted by the Government of Canada before 1887. These rights are referred to as "freehold rights".

The Alberta government departments of Environment and Sustainable Resource Development administer complementary environmental policies. The Alberta Energy & Utilities Board (AEUB) regulates oil and gas activities in the province.

The Alberta Department of Energy is responsible for administering the legislation that governs the ownership, royalty and administration of Alberta's oil, gas, oil sands, coal, metallic and other mineral resources. The Department's main objective is to manage these non-renewable resources to ensure their efficient development for the greatest possible benefit to the province and its people.

Oil Sands Royalty Structure

In 1996, Alberta announced a new generic royalty regime for oil sands based on recommendations from a joint industry/government National Oil Sands Task Force (NOSTF). This regime is defined in the Mines and Minerals Act and the Oil Sands Royalty Regulation 1997, as amended (OSRR 97). Royalty is calculated using a revenue-less-cost calculation.

In early project years before capital investment and other costs are recovered, the royalty rate is lower than the rate that is applied after costs are recovered. This helps project cash flows in early years. Once costs are recovered, the Province shares in project profits. Details are provided below.

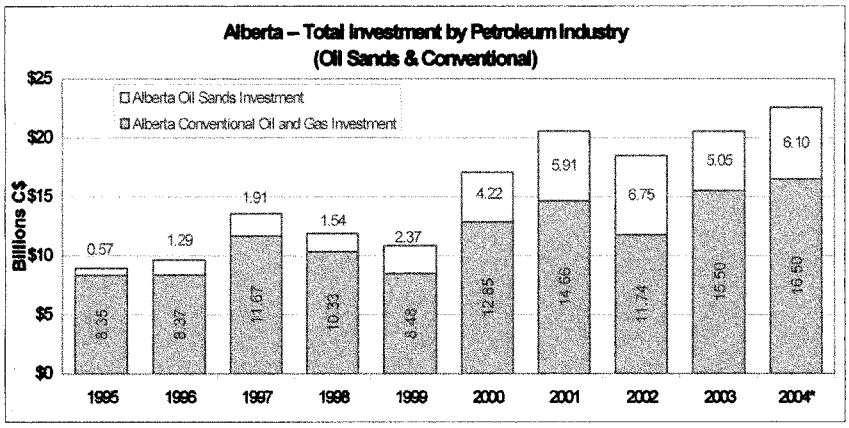
- In the pre-payout period (before the project has recovered all of its costs), projects pay royalty tied to 1% of gross revenue;
- In the post-payout period (after the project has recovered all of its costs), projects pay royalty tied to the greater of 1% of gross revenue or 25% of net revenue.

Since 1990, oil sands royalties have totaled over $2.5 billion.

Announced Investment

Since 1996, when the generic royalty regime was introduced, an estimated $35 billion of investment in the oil sands has occurred. Looking forward, it is expected that new capital investment could range from $2.5-$4 billion per year.

Figure 4: Total Investment in Petroleum Industry in Alberta 2004



*Estimate as of June 2005. Source: Canadian Association of Petroleum Producers.

Figure 5: Oil Sands Projects Planned and Under Construction

Project	Sponsors	New Production (barrels/day)	Cost (US$)
Cold Lake Phases 11-13	Imperial	30,000	$810 million
Firebag	Suncor	140,000	$810 million
Fort Hills	UTS Energy	50,000	$1,619 million
Fort MacKay	Fort MacKay First Nation	25,000	n/a
Great Divide	Connacher Oil & Gas	10,000	$121 million
Heartland Upgrader	BA Energy	75,000	$485 million
Hilda Lake	Blackrock Ventures	20,000	$210 million
Horizon	Canadian Natural Resources	233,000	$7,856 million
Jackfish	Devon	35,000	$445 million
Jackpine Mine	Shell	200,000	$1,619 million
Joslyn Creek	Deer Creek, Enerplus	10,000	$121 million
Kearl Lake	Imperial, ExxonMobil	200,000	$4,050- $6,480 million
Long Lake	Nexen, OPTI	70,000	$2,754 million
Meadow Creek	Petro-Canada	80,000	$648 million
Northwest Upgrader	Northwest Capital	50,000	$1,053 million
Muskeg Mine expansion	Shell, Chevron, Western	70,000	$810 million
Northern Lights	Synenco	80,000	$2,835 million
Scotford Upgrader	Shell, Chevron, Western	140,000	$2,187 million
Strathcona Refinery Upgrader	Petro Canada	135,000	$972 million
Sunrise	Husky Energy	200,000	n/a
Surmont	ConocoPhillips, TotalFinaElf, Devon	100,000	$1,134 million
Syncrude 21	Syncrude Canada	480,000	$6,318 million
Tucker Lake	Husky Energy	30,000	$283.5 million
Voyageur	Suncor Energy	275,000	n/a

Source: Edmonton Journal (February 2005)

The Way Forward

To date, only about 2% of the established oil sands resource has been produced. Alberta's oil sands industry is the result of multi-billion-dollar investments in infrastructure and technology required to develop the non-conventional resource. In the last five years alone, industry has allocated an estimated $28 billion towards oil sands development, and the Government of Alberta invested over $700 million over a 20-year period.

Alberta encourages the responsible development of these extensive deposits through planning and liaison among government, industry and communities to ensure a competitive royalty regime that is attractive to investors, appropriate regulations and environmental protection and the management of the Province of Alberta's rights to oil sands while taking into account some of the barriers—higher technological risk and higher capital costs—faced by oil sands developers.

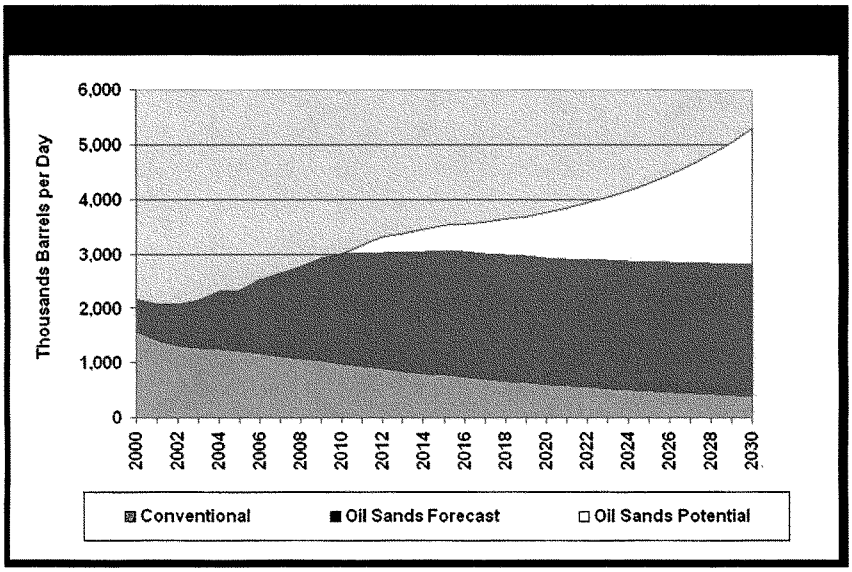
In 2004, Alberta's oil sands were the source of over half of the province's total crude oil and equivalent production and over one third of all crude oil and equivalent produced in Canada. Over the last three fiscal years, through to 2003/2004, oil sands development returned $565 million to Albertans in the form of royalties paid to the Provincial government.

Continuing technology improvements will lead to greater energy efficiency and a reduction in natural gas as a fuel input source. As the future unfolds, the only impediment to oil sands production could be shortages of skilled labour to complete the projects. Oil sands projects will compete for the same skilled workforce as the Mackenzie and Alaska natural gas pipelines.

Development of Alberta's oil sands resources represents a triumph of technological innovation. Over the years, government and industry have worked together to find innovative and economic ways to extract and process the oil sands and energy research is more important today than ever before. Working through the Alberta Energy Research Institute, the Alberta government is committed to a collaborative approach with counterparts in Canada and the United States to spur new technology and innovation programs that will reduce the impact of greenhouse gases and other emissions, and reduce the consumption of water and gas.

APPENDIX 1

Oil Sands potential: 3 million bpd by 2020, 5 million bpd by 2030



[A statement submitted for the record by Mark Mathis, Executive Director, Citizens' Alliance for Responsible Energy, follows:]

Statement of Mark Mathis, Executive Director, Citizens' Alliance for Responsible Energy

My name is Mark Mathis. My address is 8419 Vina Del Sol Dr. NE, Albuquerque, NM 87122. I am a former television news reporter and anchor. I've been a media consultant for the past eleven years. Two and a half years ago I began consulting with the Independent Petroleum Association of New Mexico. It took only a short period of time for me to understand the great frustration endured by energy producers. They are under constant attack by anti-development groups posing as environmentalists. Much of the time the accusations and rhetoric dispensed by these groups is greatly distorted if not entirely false. Within a year's time I could see that something needed to be done. It was at that time that I began contemplating starting a non-profit organization for the purpose of educating the public about energy issues. I believe a better-informed public will result in government leaders making better decisions concerning our national energy policy. I have some experience in standing up for the public. In 2001, I formed an organization called "The 505 Coalition" to fight a new and unnecessary area code from being implemented in New

Mexico. As a result of the efforts of the 505 Coalition rulings by the federal and state governments were rescinded, saving an estimated $50 million in public and private funds. I wish to apply that same type of activism to the critical task of safeguarding our nation's energy supply.

The Wildlands Project

To date, the most comprehensive environmental coalition to appear on the scene is the Wildlands Project. This coalition is the most radical in purpose: to "re-wild" America, that is, to gradually remove people and raw material production from the rural United States with no definite stopping point. In their own words:[1]

"The Wildlands Project calls for reserves established to protect wild habitat, biodiversity, ecological integrity, ecological services, and evolutionary processes. In other words, vast interconnected areas of true wilderness and wild lands. We reject the notion that wilderness is merely remote, scenic terrain suitable for backpacking. Rather, we see wilderness as the home for unfettered life, free from human technological and industrial intervention."

"Extensive roadless areas of native vegetation in various successional stages must be off-limits to human exploitation."

"To function properly, nature needs vast landscapes without roads, dams, motorized vehicles, power lines, over-flights, or other artifacts of civilization, where evolutionary and ecological processes can continue. Such wildlands are absolutely essential to protect biodiversity."

The Wildlands Project has proposed to set aside at least half of North America for "the preservation of biological diversity." The resulting "wildland reserves" would contain:

- Cores, created from public lands such as national forests and parks, allowing for little, if any, human use
- Buffers, created from private land adjoining the cores to provide additional protection;
- Corridors, a mix of public and private lands usually following along rivers and wildlife migration routes;

but would allow no cities, roads, homes, businesses, no aircraft over-flights, or natural resource extraction, i.e., an ever expanding area of America would be depopulated and de-developed.

A decade ago such proposals would not have been taken seriously. Even today this kind of proposal would seem highly unrealistic to a lot of people. However, such grand visions are not accomplished over night. They happen incrementally. Even though the term "Wildlands Project" is not widely known, it still presents a formidable threat to private property ownership, mineral and resource extraction, and national security. Countless anti-development organizations are pursing the goals of Wildlands without specifically using the term.

In the late 1990s, the Clinton Administration adopted aspects of The Wildlands Project philosophy pushed largely by Vice President Al Gore. In Mr. Clinton's term we witnessed a moratorium on road construction in undeveloped areas. There were proposals to breach dams on the Columbia River. The expansion of the Endangered Species Act continued unabated.

The Wildlands Project is technically a coalition strategy project with a single lead organization: North American Wilderness Recovery, Inc. (2000 revenue: $1,451,459), originally based in Tucson, Arizona, but relocated in 2000 to Richmond, Vermont. The organization is an outgrowth of a 1981 Earth First! idea called the North American Wilderness Recovery Project.

North American Wilderness Recovery has been supported by foundation grants since before its exemption 1992, particularly by Doug Tompkins' Foundation for Deep Ecology, in annual amounts ranging from $50,000 in 1992 to $150,000 in 1996 and 1997. The Richard and Rhoda Goldman Fund gave $75,000 in 1996 and the Educational Foundation of America gave $50,000 in 1997.[2]

A Public Deceived

We have entered the great information age. Media is all around us in television, radio, newspapers and magazines. We've got CDs, DVDs, MP3s, and satellite TV. With our computers and the Internet massive amounts of information is just a few mouse clicks away. We can learn about the most obscure subject in great depth without ever leaving our homes. And yet, in the midst of this sea of information, many Americans are either ignorant or misinformed about some the most fundamentally important issues to their lives. This is the great irony of the 21st Century. We don't live in the information age. We live in the age of disinformation.

I believe the most critical and misunderstood issue of our time is the balance between energy development and the environment. We all know we need energy for

our daily lives—electricity for lights, appliances, computers and hundreds of other devises. We know we need gasoline for our cars, jet fuel for airplanes, diesel for big trucks and ships and all kinds of other fuels such as propane and butane. We depend on this energy for absolutely everything, and yet hardly ever think about where this life-sustaining power comes from.

While Americans sit in their comfortable homes with every conceivable necessity and luxury they watch the morning news. There's another protest about "environmental destruction" caused by fossil fuels. Then they read a newspaper story about the rapid and catastrophic loss of endangered species. Then it's off to work where a radio ad informs them that some "pristine" wilderness is about to be destroyed by oil and natural gas development. While cruising along the highway they see a billboard warning them of the dangers of nuclear power. They press on the gas, take a swig of bottled water and shake their heads at those awful energy companies that are ruining their lives.

From every direction Americans are being fed a litany of lies and distortions. As preposterous as it is, people have been trained to despise the energy sources that are the foundation of unprecedented health, longevity and prosperity. Americans have been fed so much disinformation for so long that they no longer trust their own experience. They just assume the disinformation is true and those assumptions are rarely if ever challenged.

Because the public is so misinformed, a relatively small number of people who participate in vocal, well organized and very well funded activist groups are given undue influence over public policy. They demand unreasonable regulations and restrictions on energy development and they get a lot of attention from the press.

For example, The Wildlands Project and other activist groups claim we are in the "6th great extinction of species." However, a 1995 United Nations report states that there have never been so many species as there are in the modern era.[3]

On The Wildlands Website, Stanford University professor Paul Ehrlich is quoted as saying:

> *Although the Wildlands Project's call for restoring keystone species and connectivity was met, at first, with amusement, these goals have now been embraced broadly as the only realistic strategy for ending the extinction crisis.*[4]

It's surprising that The Wildlands Project would give Ehrlich such a prominent place on its website. Ehrlich is not so much famous as he is notorious for making doomsday predictions that do not come true. In 1981 Ehrlich predicted that we would lose 250,000 species every year. The widely discredited futurist claimed that half of all species would be gone by the year 2000 and that all species would be dead between 2010 and 2025.[5]

True environmentalists, such as GreenPeace founder Patrick Moore, cite biological evidence that less than one percent of species may be lost in the next century.

Moore left GreenPeace many years ago because he said the environmental movement was "basically hijacked by political and social activists". Moore was interviewed for the segment "Environmental Hysteria" by Showtime's Penn & Teller program. Moore told Penn & Teller that these phony environmentalists, "came in and very cleverly learned how to use green rhetoric or green language to cloak agendas that actually had more to do with anti-corporatism, anti-globalization, anti-business and very little to do with science or ecology."[6]

The Wildlands Project and other groups that support the same anti-development agenda are effective in spreading disinformation through their skill in using the news media. They know that they can make outrageous claims and the chance that those claims will actually be challenged is very small. They know that journalists typically don't know enough about these complex issues to even ask the right questions, let alone to challenge the sensational assumptions. Reporters are not given enough time or resources to do more than simply repeat the activists' claims. Of course, some reporters are believers in the obstructionist movement and their bias heavily influences their stories. But more than anything, the press cannot resist emotional, sensational, fear-based claims. It's their bread and butter in the 21st century.

Journalistic arrogance, of course, is another problem. Syndicated columnist Stanley Crouch recently informed readers of The New York Daily News, "The recent congressional vote for Arctic drilling would not have been necessary if we had maintained commitment to developing nuclear power as an energy source." It apparently didn't occur to Mr. Crouch that there's no such thing as a nuclear-powered car, tractor-trailer or airplane.[7]

I have considerable knowledge in this area of media manipulation. I was a news reporter for nine years in four states and I've been a media consultant for more than 11 years. In my book, Feeding the Media Beast, I devote a chapter to "The Rule

of Emotion" and another to "The Rule of Repetition". Anti-development groups are very good at using these powerful rules to their advantage.[8]

The Renewable Deception

Supporters of the Wildlands Project philosophy are big supporters of renewable energy sources such as wind, solar, and biomass. They continually urge the public and government leaders to reject fossil fuels and to embrace the energy sources of the 21st century. These kinds of politically correct statements receive broad approval because they sound so good. However, the fact is renewable energy sources running our world is nothing more than pure fantasy for at least several more decades and probably longer.[9]

Professional obstructionists and even some politicians have led people believe that a greater investment in wind and solar power will somehow make us less dependent on foreign oil. That's ridiculous. Wind turbines and solar panels generate electricity, which does nothing to replace the oil that fuels virtually all forms of transportation. Even the electricity generation of wind and solar power is minuscule at this point, contributing less than one half of one percent to our electricity needs.[10]

To the uninformed, this distinction may seem trivial. In reality its importance couldn't be greater. We don't have an electricity problem in this country (though we could use more power plants and an upgraded grid); we have a deadly serious liquid fuels crisis that threatens our economy, our national security and indeed all that we hold dear.

There are other groups such as the Energy Future Coalition and The Governors' Ethanol Coalition made up of governors from 33 states. These organizations want Congress to increase a federally mandated use of ethanol above the 5 billion gallons required by 2012.[11] These governors score points—and votes—by appearing to actually be doing something about our thirst for foreign oil and desire to have a cleaner environment. Farm belt governors score double points because 95% of ethanol is made from corn.

However, this is just another energy deception. It takes more fuel to produce and deliver ethanol than it provides, meaning we import more foreign oil, not less. While ethanol is advertised as burning cleaner than gasoline, on balance it actually produces more and worse pollution. Ethanol emits higher levels of NOx emissions contributing to smog, and it makes gasoline evaporate faster, reducing its value while increasing pollution. It also must be shipped separately and mixed at distribution terminals, which simultaneously drives up costs, fuel usage and emissions.[12]

The Big Hammer: The Endangered Species Act

No single tool has been more effective in advancing the goals of The Wildlands Project than the Endangered Species Act. Say "Endangered Species Act" and most Americans believe this is a federal law that protects species in danger of becoming extinct. While that was the original intent, today the Act has very little to do with protecting species in trouble. It is a simply a tool for anti-development groups posing as environmentalists to shut down any and all uses of public land, energy development being number one on the list.

One of the fundamental flaws of the ESA is that species do not recognize state boundaries. If a species is determined to be "endangered" in one state it may become listed as such even though an abundance of the species exist in other parts of the country or in other nations. For example, the Aplomado Falcon is listed as endangered in New Mexico when the species hasn't even existed in the state for the past half century.[13] The Bureau of Land Management has restricted energy development on 36,000 acres on Otero Mesa just in case the falcon decides to come back. Even worse, the falcon can be found in great abundance on the entire continent of South America, throughout Central America, all of Mexico, and into Texas.[14] An additional 88,000 acres on Otero Mesa are off-limits for other conservation concerns. Dozens upon dozens of cases such as this can be found all across the country.

Another big problem is that once a species is listed it is extraordinarily difficult to get it de-listed. In the 32-year history of the ESA only 10 species have been removed from the endangered list because of "recovery". Even then, critics charge that some of those species were saved by private efforts and other activities such the banning of DDT.

In New Mexico the Gila Trout was first listed as endangered in 1967. The U.S. Fish & Wildlife Service proposed downgrading it to threatened in 1987 but under pressure withdrew the proposal. Another request came in 1996. It didn't happen. Today the USFW is attempting a third time but is running into stiff objections from anti-development groups.[15]

Enforcing the ESA is very expensive to taxpayers as well as private property owners. In the west, the U.S. Fish and Wildlife Service estimates it will cost about $30

million to $40 million every year to protect the endangered southwestern willow flycatcher. Unfortunately, this kind of outrageous expense for species protection is the rule rather than the exception. Remember, there are 1,262 Endangered Species and obstructionists are filing lawsuits and lobbying hard to have more added all the time.

There are many other flaws in the Endangered Species Act such as the fact that in many cases access to land is restricted based on the "Best Available Data", which often stands for "BAD" data because data are incomplete and sometimes non-existent. Another flaw is the fact that private landowners lose use of their land because of an endangered species and they receive no compensation from the government. There are more problems, however the intent of this testimony is not to make suggestions on how to fix the ESA, but simply to point out that the Act is highly flawed and yet very powerful in restricting access to land for all purposes, most importantly to energy development.

Energy is Everything

It is almost impossible to overstate the importance of oil and its powerful brother, natural gas. Without them our world would be completely different, more different than any of us can possibly imagine.

Look around you and try to spot a single item that would still be there if oil were not. When people think of oil and natural gas they typically consider its obvious uses'gasoline for the car, a lubricant for the engine, and a power source for electricity generation and the heating of homes. What about rubber for tires, shoes, and seals on refrigerators, ovens, and car doors? Consider the importance of asphalt, fertilizers, pesticides, and glue. What would life be like without magic markers, lipstick, pantyhose, credit cards, dental floss, toothpaste, baby bottles, telephones, TVs, computers, soccer balls, paint, and synthetic fibers for today's clothing?

The vast quantity of everyday items that contain some byproduct of petroleum is astonishing. Take these products away and our world would come to a sudden and catastrophic end. If somehow we could instantly remove the contribution of petroleum to our world you would find yourself standing naked and unsheltered in an open landscape among millions of other naked and unsheltered souls.

It's a little unnerving just to think about it. There's only one thing more important to our survival than oil and natural gas, and that's oxygen. Yes, water, food, clothing, and shelter are essential, but in today's world the vast majority of the population cannot get these life-sustaining necessities without petroleum.

Yet, in spite of these sobering realities, a misinformed public stands by while access to oil and natural gas are denied under the pretense of "environmental protection."

Oil & National Defense: A Sobering Reality

Oil—as well as all other energy sources—is directly tied to the success and survival of the United States of America. The same can be said of any other country. Fundamentally, no society can endure—let alone prosper—without two things: an adequate and affordable food supply and the availability of affordable energy. Because our food supply is almost completely dependent on oil, petroleum is the most important commodity we have.

While it's quite clear that our economy and standard of living are completely dependent upon oil, it may be less clear that petroleum is a key ingredient in our freedom, too. Without adequate fuel supplies for fighter jets, battleships, tanks and other armored vehicles America would be vulnerable to any nation that wished to take what we have as their own, and that includes our liberty as well.

Allied forces defeated the Axis powers in World War II for a variety of reasons—brave men and women, intelligent military leaders, and a home-front that made great sacrifices to give the military all that it needed while still running a nation. However, no level of bravery or sacrifice would have mattered if the United States hadn't had sufficient oil supplies to fuel victory.

Freedom isn't free. It takes enormous sums of bravery, skill, passion, human ingenuity and the fuel to make it all work.

A Promising Alternative: Oil Shale

One of the most promising alternatives to oil is what's called "oil shale". The potential resource is enormous. It's estimated that there is over 200 times more oil shale than there are conventional reserves. Better yet, the United States is estimated to have 62% of the world's potentially recoverable oil shale resources at 2 trillion barrels. According to The World Energy Council the largest of the deposits is found in the 42,700 km2 Eocene Green River formation in north-western Colorado, northeastern Utah and southwestern Wyoming.[16]

The name is actually a misnomer because it does not contain oil and it is not often found in shale. The organic material in oil shale is kerogen and it's contained in a hard rock called marl. When processed, kerogen can be converted into a substance similar to petroleum. During this process the organic material is liquefied and processed into an oil-type substance. The quality of the product is typically better than the lowest grade of oil produced from conventional reserves.

Unfortunately, oil shale poses several significant problems. Processing of oil shale requires significant amounts of energy and water. It also produces massive amounts of waste product. In the 1970's major oil companies in the U.S. spent billions of dollars in various unsuccessful attempts to commercially extract shale oil. However, as the price of conventional oil rises the economics of shale oil will improve. When that happens we can expect groups supporting The Wildlands Project philosophy to mount a well-funded and well-organized protest. As always, disinformation will lead their plan of attack.

A Difficult Task

Getting the American public and government leaders to focus on the critical importance of responsible domestic energy production is no easy task. Re-educating the public about the nation's true environmental condition will be even more difficult. However, CARE was formed to address these issues because the stakes are extraordinarily high. The stability of our economy and the foundation of our national security are directly tied to our ability to produce domestic energy. It is bad public policy to continue to become more dependent on foreign and often unstable governments to fulfill our energy requirements, especially when environmentally responsible production is a reality today.

ENDNOTES

[1] Ron Arnold, Undue Influence, Free Enterprise Press, 1999, p. 171-172; www.twp.org, Internet Archive 1998

[2] North American Wilderness Recovery, IRS form 990, 1993-1997; Foundation Center Database

[3] Bjorn Lomborg, The Skeptical Environmentalist, Cambridge Press, 1988, p. 249; United Nations Environment Programme 1995: 204, 206, 207

[4] The Wildlands Project Website: http://www.twp.org:80/cms/page1089.cfm

[5] Lomborg, The Skeptical Environmentalist, p. 249

[6] "Penn & Teller BullShit," Showtime Networks, "Environmental Hysteria" Season 1

[7] Albuquerque Journal, April 1, 2005

[8] Mark Mathis, Feeding the Media Beast: An Easy Recipe for Great Publicity, Purdue University Press, May, 2002

[9] Robert L. Bradley, Richard W. Fulmer, Energy: The Master Resource, p.185-186 Kendall Hunt Publishing Co. 2004

[10] Energy Information Administration, U.S. Department of Energy, "Renewable Energy Trends 2003", July 2004, p. 5

[11] Energy Future Coalition, www.energyfuturecoalition.org; The Governors' Ethanol Coalition, www.ethanol-gec.org/Transmittal—Letter—to—White—House—pdf

[12] Robert L. Bradley, Richard W. Fulmer, Energy: The Master Resource, p.57-58, 129-130, 131, 134-135, 162, Kendall Hunt Publishing Co. 2004

[13] The Peregrine Fund, www.peregrinefund.org, restoration projects page, Aplomado Falcon

[14] The Peregrine Fund, www.peregrinefund.org/Explore—Raptors/falcons/aplomado.html

[15] Albuquerque Journal, May 18, 2005

[16] World Energy Council: www.worldenergy.org/wec-geis/publications/reports/ser/shale/shale.asp

OVERSIGHT HEARING ON "THE VAST NORTH AMERICAN RESOURCE POTENTIAL OF OIL SHALE, OIL SANDS, AND HEAVY OILS," PART 2

Thursday, June 30, 2005
U.S. House of Representatives
Subcommittee on Energy and Mineral Resources
Committee on Resources
Washington, D.C.

The Subcommittee met, pursuant to notice, at 10:02 a.m., in Room 1324, Longworth House Office Building, Hon. Jim Gibbons [Chairman of the Subcommittee] presiding.

Present: Representatives Cannon, Pearce, and Drake.

STATEMENT OF THE HON. JIM GIBBONS, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF NEVADA

Mr. GIBBONS. The Subcommittee on Energy and Mineral Resources will come to order.

Today's hearing, entitled "The Vast North American Resource Potential of Oil Shale, Oil Sands, and Heavy Oils," is Part Two of a series of hearings. The Subcommittee today meets to hold its second of those two-part hearings on this very subject.

STATEMENT OF HON. JIM GIBBONS, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF NEVADA

Mr. GIBBONS. At part one of this hearing, we focused on dispelling the myth that the United States has only three percent of the world's oil reserves. A report by the Department of Energy, that can be found in the Subcommittee's website, estimates that the U.S. has two trillion barrels of oil shale, out of the 2.6 trillion barrels found worldwide. The domestic production possible from this resource would be sufficient to replace all of the United States' foreign oil imports except those from Canada and Mexico.

Also, at the first part of this hearing, this Subcommittee heard from resource experts, resource producers, and state and local government representatives on a range of topics, with a focus on the vast North American unconventional oil resource potential.

Witnesses discussed the feasibility of developing unconventional oil resources through the lessons learned from the oil sands production in Alberta, Canada; as well as recommendations to facilitate commercial leasing and production of oil from federally owned oil

shale. We learned that unconventional oil development is not only feasible, but has the promise of delivering low-cost oil to consumers.

I was very encouraged by the enthusiasm for oil shale production at the last hearing, and look forward to hearing from officials from the Departments of Defense, Energy, and Interior, on their view of the Federal Government's role in managing, utilizing, and facilitating production of these unconventional sources of oil.

With approximately 70 percent of the land containing potential oil shale development being owned by the Federal Government, the Federal Government will have a vital role in the facilitation of production. I believe the Government has a responsibility for development of these valuable resources, and this includes looking for ways to remove barriers to production.

As this Subcommittee has discussed in previous hearings, dependence on trans-oceanic energy imports is dangerous to our economic and national security. Despite promises from OPEC to increase production from member countries, oil prices have continued their movement higher and higher. Recent projections show that oil prices could reach more than $100 per barrel in the not-too-distant future.

World oil supplies are growing tighter due to the inability of oil production to grow as fast as increases in oil demand; primarily because of increased demand from countries with rapidly growing economies, such as China and India.

Global oil supplies are also strained because areas that would be highly prospective for energy production are either off limits to leasing, or the resources are not otherwise being made available for leasing; such as America's vast resources of oil shale.

It is vital as a nation that we look to unconventional and non-traditional sources of energy to foster greater North American energy independence.

I look forward to the testimony of our witnesses today. And when our Ranking Member arrives, or a member of the other party arrives for this hearing, we will offer them an opportunity to make an opening statement.

[The prepared statement of Mr. Gibbons follows:]

Statement of The Honorable Jim Gibbons, Chairman, Subcommittee on Energy and Mineral Resources

The Subcommittee meets today to hold the second of a two-part hearing on "The Vast North American Resource Potential of Oil Shale, Oil Sands, and Heavy Oils".

At Part 1 of this hearing we focused on dispelling the myth that the United States has only 3 percent % of the world's oil reserves.

A report by the Department of Energy that can be found on the Subcommittee website estimates that the U.S. has 2 TRILLION barrels of oil shale out of the 2.6 trillion barrels found worldwide.

The domestic production possible from this resource would be sufficient to replace all of the United States' foreign oil imports except those from Canada and Mexico.

Also at the first part of this hearing, the Subcommittee heard from resource experts, resource producers, and State and local government representatives on a range of topics, with a focus on the vast North American unconventional oil resource potential.

Witnesses discussed the feasibility of developing unconventional oil resources.

Through the lessons learned from the oil sands production in Alberta, Canada, as well as recommendations to facilitate commercial leasing and production of oil from federally-owned oil shale, we learned that unconventional oil development is not only feasible, but has the promise of delivering lower-cost oil to consumers.

I was very encouraged by the enthusiasm for oil shale production at the last hearing and look forward to hearing from officials from the Departments of Defense, Energy and Interior on their view of the federal government's role in managing, utilizing, and facilitating production of the these unconventional sources of oil.

With approximately 70 percent of the land containing potential for oil shale development being owned by the federal government, the federal government will have a vital role in the facilitation of production.

I believe the government has a responsibility to development of these valuable resources and this includes looking for ways to remove barriers to production.

As this Subcommittee has discussed in previous hearings, dependence on transoceanic energy imports is dangerous to our economic and national security.

Despite promises from OPEC to increase production from member countries, oil prices have continued their movement higher.

Recent projections show that oil prices could reach more than $100 per barrel in the not too distant future.

World oil supplies are growing tighter due to the inability of oil production to grow as fast as increases in oil demand, primarily because of increased demand from countries with rapidly growing economies such as China and India.

Global oil supplies are also strained because areas that would be highly prospective for energy production are either off-limits to leasing or the resources are not otherwise being made available for leasing, such as America's vast resources of oil shale.

It is vital that as a nation we look to unconventional and non-traditional sources of energy to foster greater North American energy independence.

I look forward to hearing the testimony of our witnesses.

Mr. GIBBONS. At this time, I would like to welcome our guests and witnesses on our panel: Dr. Theodore K. Barna, Assistant Deputy Under Secretary of Defense, Advanced Systems and Concepts, Office of the Secretary of Defense for the U.S. Department of Defense; Mr. Mark Maddox, Principal Deputy Assistant Secretary, Office of Fossil Energy, U.S. Department of Energy; and Mr. Chad Calvert, Deputy Assistant Secretary, Land and Minerals Management, U.S. Department of the Interior.

Gentlemen, before I turn to your testimony, we have a procedure to swear in our witnesses. So if each you would, rise and raise your right hand.

[Witnesses sworn.]

Mr. GIBBONS. Let the record reflect that each of the witnesses answered in the affirmative.

We will turn now to Dr. Barna, Assistant Deputy Under Secretary of Defense, for your remarks. Dr. Barna, the floor is yours. We look forward to your testimony.

We do have a light system here. Each of your written remarks will be entered into the record. You may feel free to summarize or discuss your ideas within the five-minute time limit. But since I am the only one here, you can take as much time as you want.

[Laughter.]

Mr. GIBBONS. Dr. Barna.

STATEMENT OF THEODORE K. BARNA, ASSISTANT DEPUTY UNDER SECRETARY OF DEFENSE, ADVANCED SYSTEMS AND CONCEPTS, OFFICE OF THE SECRETARY OF DEFENSE, U.S. DEPARTMENT OF DEFENSE

Dr. BARNA. Thank you very much, Mr. Chairman. I am Ted Barna, and I am very honored and delighted today to have the chance to appear here and discuss the production of fuels for the Department of Defense.

While I believe the Department of Defense, DOD, has legitimate concerns about future access to energy—for example, increasing amounts of imports and refined products, which you just mentioned—today I would like to concentrate on the work that we, DOD, have performed to investigate and certify these fuels in military equipment. The end goal is to validate the use of these fuels, and also reduce the number of fuels that we need to operate.

We started this, actually, back in 2003, before the current run-up in prices, when I was asked to manage a program designed to investigate alternative fuels. This is an ongoing study. It was initially sponsored by Senator Inhofe and Congressmen Sullivan and Cole, all of Oklahoma. And we researched fuels produced via the Fischer Tropsch process from natural gas.

Now, to accomplish this, I initiated a multi-service, multi-agency program, led by the Army's National Automobile Center—Automotive Center, I guess, the NAC—in Warren, Michigan. And the NAC then formed a collaborative program with the Air Force, with the Navy, with the Department of Energy, with the Department of Energy National Labs in West Virginia and Pennsylvania, and Southwest Research Institute in San Antonio.

We also were joined by several universities and industry; the industry partner being Syntroleum Corporation, who actually made the fuel. We would use this to conduct a preliminary evaluation of how these fuels could be, or would be, used in aircraft, tactical vehicles, and ships.

It is important to note that we did not address any of the economics of manufacturing these fuels. We were looking solely at their potential use by the military.

As a result of this initial look, this initial look indicated that these Fischer Tropsch fuels have a strong potential to produce lower-pollutant emissions in diesel engines, reduce particulate emissions in jet engines; they have superior high temperature and low temperature characteristics; and they actually provide improved storage characteristics, especially on ships.

Based on these positive results, in 2004 I expanded this effort then to include not just Fischer Tropsch fuel made from natural gas, but looked at all the variety of resources we as a nation have at our disposal; mainly, oil shale, sands, coal, biomass, and petroleum coke.

And although this, what we term as our OSD Clean Fuel Initiative, looks at the total energy picture, today I will just discuss two of these: coal, very briefly; and shale, in more detail.

As you mentioned the U.S. has the necessary resources of coal in Appalachia, the western United States, and Alaska—and this is probably in excess of 800 billion barrels equivalent of oil—to produce clean military fuels using Fischer Tropsch processes. And as I stated previously, our work thus far has demonstrated these fuels have excellent characteristics, and will be beneficial.

In addition, the gasification process used to produce these fuels theoretically can be used to generate electricity, hydrogen, fertilizers, and chemicals. So it is a good opportunity for industry.

America's shale, though, western shale, as you stated, deposits in Colorado, Utah, and Wyoming, contain the equivalent of at least a

trillion barrels. And that would be well suited for producing a premium quality diesel and jet fuel for the military.

Eastern oil shale also represents about 400 billion barrels potentially of oil. And 90 percent of these near-surface mineable resources are in Kentucky, Ohio, Indiana, and Tennessee. So we do have shale in the east, actually; not in the strong concentrations we have in the west.

DOD tests conducted in the early 1980s, back when we were interested in shale, demonstrated that shale oil derived from kerogen, when properly hydrogenated, has properties similar to crude oil. For example, a U.S. Navy report of the period states that reasonable quality JP-5, which is the Navy jet fuel, and a marine diesel could be produced from shale oil, by virtue of their tests.

At the time, the Air Force also investigated JP-4, which we all remember as our old jet fuel from the Air Force, and performance was found satisfactory; although there were some lubricity issues, that are easily solved.

A fresh look, though, at shale-derived fuels will be required, because now we use a different fuel. It's called JP-8, which is a version of the commercial Jet-A-1. This fresh test includes new specifications designed to yield fuels that produce less tailpipe emission SOXs and particulate matter, and have improved low temperature characteristics; and then to certify use in all military tactical vehicles, such as tanks, ships, and airplanes.

We know that this is just a burgeoning industry, but we have already made arrangements with Shell Oil to get some of their shale-derived fuel and start this testing.

Looking in the future, shale-derived fuels could also be used in fuel cells and advanced propulsion systems, such as hypersonics.

Therefore, based on our experience from the '80s, plus new specifications and applications for extraction and refining, there is no reason to expect that shale oil cannot be processed into high-quality, clean fuels which are suitable for tactical and non-tactical military equipment.

So in conclusion, if economic, utilizing all our energy sources—the largest of which are shale and coal—while reducing the number of fuels we employ, would have significant operational and logistics consequences for the Department of Defense. Finally, cleaner fuels would bring DOD more in line with current and evolving EPA regulations, and contribute to advanced technologies like hydrogen vehicles, fuel cells, and scram jets.

Mr. Chairman, I look forward to working with you and members of the Committee as we pursue this mission of improving DOD's energy security. Thank you.

[The prepared statement of Dr. Barna follows:]

Statement of Dr. Theodore K. (Ted) Barna, Assistant Deputy Under Secretary of Defense, (Advanced Systems and Concepts)

Introduction

Mr. Chairman and members of the Committee, I am Dr. Ted Barna, Assistant Deputy Under Secretary of Defense, Advanced Systems and Concepts. I am honored and delighted to have the chance to appear today to discuss opportunities to produce superior fuels for the Department of Defense (DoD).

DoD's Concerns

Supply vulnerabilities: As you are well aware, the U.S. currently imports over 56% percent of its oil and the Energy Information Agency estimates that it will increase to 68% by 2025.

Refining concerns: We are also increasingly dependent on foreign refined fuels, estimated to increase to four million barrels a day of finished product by 2025.

EPA Exemptions: The military currently has EPA national security exemptions to use jet fuels in our tactical equipment that in some cases exceed local EPA requirements. As President Bush stated "America must have an energy policy that plans for the future, but meets the needs of today. I believe we can develop our natural resources and protect the environment."

Reduce the number of fuels: If economic alternatives can be founds, a reduction in the number of fuels DoD currently uses would generate a tremendous operational and logistic benefit. Therefore, a significant goal of our ongoing program is geared to eventually having one battlefield fuel which can be used in the air, on ground, or at sea. Since this fuel would be suitable for the intended function (fit for use) the source of the fuel (synthetic, shale, biomass, petroleum) would be immaterial to the ultimate consumer.

Sources of energy: A quick estimate of total energy resources (shale, coal, oil, and other resources such as biomass and petcoke) comes to approximately 2.3 trillion barrels (bbl) potentially available in the US. (This total estimate includes: 1.4 trillion bbl of shale; 800 billion bbl coal; 60 billion bbl of petroleum, including enhanced oil recovery using CO2; plus renewables, which are not yet quantified). This compares with an estimated 700+ billion barrels total proved reserves (producible at today's prices) in the entire Middle East.) Please note, ("resource" is a technical term that indicates supplies of energy that may be in the ground, but are not economically producible at today's prices).

Note: EIA estimates U.S. proved oil reserves at 24.0 billion barrels as of the beginning of 2003. For technically recoverable oil resources, EIA uses estimates from the U.S. Geological Survey and Mineral Management Services, to arrive at an estimate of 142.8 billion barrels as of the beginning of 2003. The 800 billion bbl estimate for coal represents recoverable reserves only, not total resources. DOE estimates oil shale resources at more than 2 trillion barrels, although the economics of the recoverability of this resource is not considered.

In sum, if economic, the development of the vast national energy resources we have in this country could provide a dispersed, diverse, less vulnerable supply of fuels for the military such that it can meet its national security objectives in the near and far term.

DoD Involvement

Starting in 2003, before the current run up in prices, I was asked to manage a program designed to investigate alternative fuels. This ongoing study, sponsored by Senator Inhofe and Congressmen Sullivan and Cole, all of Oklahoma, researched fuels produced via the Fischer Tropsch (FT) process from natural gas. To accomplish this task I initiated a joint program, led by the Army National Automotive Research Center (NAC) in Warren, Michigan, to investigate the military utility of these fuels and to evaluate the potential of producing and using a new generation of clean fuels for the military. The NAC in turn formed a joint collaborative program with the Air Force Research Laboratory at Wright-Patterson AFB, Ohio, the Naval Air Systems Command located at Patuxent River, Maryland, the Department of Energy National Technology Laboratory in Pittsburgh, Pennsylvania, and the Southwest Research Institute, San Antonio, Texas. They were joined by the University of Dayton Research Institute in Dayton, Ohio, and Syntroleum Corporation, Tulsa, Oklahoma (which supplied the fuel) to conduct a preliminary evaluation of the technological potential of these fuels for use in aircraft, tactical vehicles and ships.

The team has concluded a preliminary assessment of the chemical properties, storage stability, thermal stability, low temperature characteristics and emissions in diesel and jet engines. It found that neat (100%) FT fuel will require modification for use in legacy (older) military equipment, but these modifications can be made with existing technologies. For example, since the fuel is highly processed, it has a lower lubricity than normal petroleum derived fuels and could lead to premature pump failures. The research team has determined that conventional lubricity additives or blends with petroleum derived fuels could easily remedy this problem. Also, since these fuels are very good solvents, they can cause the elastomers (seals and o'rings) found in legacy systems to shrink and potentially cause leaks. Continuing research to solve this problem includes novel additives, aromatic blends, and blends with conventional petroleum derived fuels.

Bottom line is these are fuels that meet or exceed military and EPA standards. Use of pure synthetic fuels pose some difficulties in the areas of lubricity and seal swell, especially in legacy (older) equipment, but the problems can be solved at some cost, initially by using blends and ultimately by the addition of additives. They also bring us more in line with EPA and EU regulations. Testing and characterization now pro-actively identifies and could significantly ease future difficulties.

It is important to note this effort did not address the economics of using clean fuels for the military, nor whether or not it is ever likely that commercial scale production by the private sector will occur.

The results of this initial look indicated FT fuels, using updated processes and procedures, have the strong potential to produce lower pollutant emissions in diesel engines, reduce particulate emissions in jet engines, have superior high temperature and low temperature characteristics, and provide improved storage characteristics. Even the use of clean fuel blends, designed to counter problems of lubricity and seal-swell, provide significant (50%) reductions in tailpipe emissions.

Based on these finding, in 2004 I expanded this initial effort to include a wider variety of resources for the production of clean fuels, notably: oil shale, oil sands, coal, biomass and petroleum coke. Although this OSD Clean Fuel Initiative looks at the total energy picture, today I'll concentrate on only two of these resources: coal (briefly) and shale (in more detail).

Coal

The U.S. has the necessary recoverable reserves of coal in Appalachia, the western United States, and Alaska (approximately equivalent to 800 billion barrels) to produce clean military fuels via the above mentioned Fischer-Tropsch process or through direct liquefaction. In either case, since the coal is gasified to carbon monoxide and hydrogen, then recombined over a catalyst, these processes remove most if not all pollutants, including sulfur and mercury. When coupled with carbon strategies, such as CO2-sequestration, while more costly than alternatives, the entire process is certainly more environmentally friendly. In addition to producing military fuels, this coal gasification process can be used technically to generate electricity, hydrogen, fertilizers, and chemicals.

Oil Shale

America's Western Oil Shale is the largest unexploited hydrocarbon resource on earth. It's estimated that deposits in Colorado, Utah and Wyoming contain approximately 1 trillion barrels of recoverable oil (equivalent) that are well suited for producing premium quality diesel and jet fuels for the military. For example, Shell Oil is currently conducting a shale oil conversion pilot project which will convert kerogen to oil and gas via thermal cracking and in situ hydrogenation. Eastern Oil Shale could provide 400 billion of barrels of oil based on estimates in the 1990's, (Dr. Ari Geertsema, Center for Energy Institute, University of Kentucky). These eastern oil shale deposits are not as concentrated as western shale It is of interest that, while not as concentrated a Western Shale, Eastern Shales are low in carbonate content and retorting will not cause decomposition and the production of large amounts of CO2. Greater than 90% of the near-surface mineable resources are in Kentucky, Ohio, Indiana and Tennessee.

DoD demonstrated in the early 1980's that shale oil derived from kerogen, when properly hydrogenated, has properties similar to crude oil. Since no shale fuels have been produced lately because of the cost of production, our evaluation relies on interpreting archival data. The technical literature reports early laboratory work on producing quality jet fuels from shale oil as early as 1951. Understandably, DoD interest increased dramatically in 1973 following the Arab Oil Embargo.

The initial large scale evaluations of petroleum refined from shale oil were sponsored by the Navy and the Naval Petroleum and Oil Shale Reserves Office. These investigations looked at gasoline, JP-4 (Air Force standard jet fuel during this period), JP-5 (Navy aircraft fuel), diesel fuel marine (DFM) and a heavy fuel oil. Eventually, quality fuels were produced under these contracts and the Navy and DOE conducted extensive tests in military and commercial equipment. The initial focus of the testing was on the DFM product for naval shipboard use and included evaluating the fuel in fuel pumps and fuel distribution equipment to assure compatibility with Navy fuel system materials. After a complete evaluation, the Navy conducted hardware tests in diesel engines, Navy boilers, marine gas turbine engines, and conducted a shipboard test on the USS Scott. The Navy reports showed that DFM produced from shale oil was suitable for shipboard use.

The Navy also conducted tests of a shale derived JP-5 fuel in aircraft engines. The Navy report of the period states that a reasonable quality JP-5 could be produced (although the fuel was somewhat more corrosive than some petroleum derived fuels)

and required the addition of lubricity additives for fuel pump durability. Engine tests were conducted by Allison on the T63-A-51 and T56-A-14 engines; General Electric on the TF34-GE-400 engine; and Pratt and Whitney TF30-P-414 engine. The shale derived JP-5 fuel performed satisfactory in all tests.

At the same time, the Air Force investigated shale derived JP-4 fuels. The fuel was tested in combustion rig tests conducted by Pratt and Whitney and General Electric and the fuel found to be suitable for testing in full scale engines and aircraft. Accelerated durability testing was also conducted by United Technologies on shale derived JP-4 in the TF30 and F100 fighter engines. Performance was found to be satisfactory in these engines tests, although the reports recommended additional research on fuel lubricity additives. Based on these positive results from the engine tests, a plan was developed to use the fuel at Air Force Bases in Utah (Hill AFB) and Idaho (Mountain Home AFB). The program was abruptly brought to an end by the announcement by Exxon of the closure of the Colony Project signaling the end of this phase of oil shale development.

Therefore, our conclusion is that shale oil can technically be processed using conventional refining techniques into high quality clean fuels, which are suitable for general use, to include use in tactical military equipment.

Notwithstanding these favorable results, a fresh look at shale derived fuels will be required by the military since the main jet turbine fuel is now JP-8, a version of commercial jet fuel Jet-A1, which replaces the JP-4 (gasoline/kerosene fuel blend) used by the Air Force and diesel fuel used by the Army. This fresh look includes developing new specifications designed to yield fuels that produce less tailpipe emissions (SOx and particulates), have improved low temperature characteristics, and allow use in all military tactical vehicles such as Army tanks, Navy ships, and Air Force and Navy aircraft.

Looking to the future, economic shale derived fuels produced to clean fuels specifications could also be used in fuel cells and advanced propulsions systems required for hypersonics.

Therefore, based on our experience from the 1980's, plus new specifications and application of modern extraction and refining techniques, there is no reason to expect that shale oil cannot technically be processed into high quality clean fuels, which are suitable for use in tactical and non-tactical military equipment.

Conclusion

If economic, a reduced number of fuels would have significant operational and logistics consequences, and supply chain vulnerability would be reduced by having more, dispersed refineries. Cleaner fuels would bring DoD more in line with current, and evolving EPA regulations, reduce the possibility of limits on potential deployment (i.e. EU) locations, and contribute to technology advancements, (for example hydrogen vehicles, fuel cells, and scram jets).

Mr. Chairman, I look forward to working with you and the members of the Committee as we pursue our mission of providing DoD energy security.

I would be pleased to answer any questions.

Response to questions submitted for the record by Dr. Theodore K. (Ted) Barna, Assistant Deputy Under Secretary of Defense, (Advanced Systems and Concepts)

1. *What are the three most important things that the Federal Government can do to ensure timely production of large volumes of oil from oil shale?*

First, the Department of Defense (DoD) can act as a preferred customer of the jet fuel produced from the shale. Historically, DoD was slated to be the first user of fuels produced from oil shale in the late 1970's and early 1980's. Plans were in place to use the fuel at key Hill and Mountain Home USAF bases prior to the program being cancelled. A similar approach to be a dedicated customer would be a good first step to a broader usage by the DoD.

Second, another key role the DoD can play is to evaluate, certify, and demonstrate that fuels produced from the shale oil are fit-for-purpose for use in trucks, aircraft and ships. DoD working closely with the original equipment manufactures (OEM's) to assure compatibility, performance and durability, paves the way for the military to use fuels produced from this resource.

Third, DoD can serve as the focal point for developing new fuel specifications, in concert with manufacturers, that meet the needs of the military and civilian clients. These revisions are long overdue and can serve as the basis for improved efficiencies and lessened logistics tails.

2. *Specifically, what does the Department of Defense plan to do, if anything, to ensure production of oil from oil shale? Would it be possible for DOD to enter into long-term contracts for the purchase of oil produced from oil shale, with provisions allowing for protection of the producer from downside price risks, while allowing DOD to be protected against large price increases?*

The Department of Defense is following the programmatic efforts of the Department of Energy and industry to develop the resources. The DoD is developing plans to evaluate, certify, demonstrate and implement use of fuels produced from oil shale that would mesh with the development of the resource.

Currently the DoD by statute can enter in to multiyear contracts for fuel produced from shale oil at market price. That is, while the contract is for a longer term, the price is renegotiated yearly. The DoD could offer a preference for fuel produced from oil shale in its open solicitations for jet fuel. Currently DoD is prohibited from entering into contracts that would allow protection of the producer for downside price risk, or the DoD to be protected against large price increases (floors and collars).

3. *What quantity of oil and products derived from oil does DOD consume annually? Of this amount, how much do you foresee could be provided by oil and products produced from oil shale?*

The Defense Energy Support Center (DESC) issued contracts in FY04 to purchase 127.4 million barrels (5.35 billion gallons) of fuel. 75.6 million barrels (3.18 billion gallons) was purchased domestically. (Reference DESC Fact Book 2004) When the oil shale resource is developed, shale derived fuels could provide a significant share of the fuel we use domestically and supply key military bases in the western United States.

4. *Does DOD consider that relying on vast quantities of transoceanic oil imports is a threat to the national security of the United States?*

For the foreseeable future, the U.S. will continue to rely on imports for a majority of its fuel needs. However, fuel is a fungible commodity traded in an efficient global market. Reselling quickly and substantially mitigates the effects of supply interruptions at any one source as well as to any particular market.

While the U.S. economy will be affected by long-term increases in global fuel prices stemming from, e.g., increased global demand and political instability among energy suppliers, several factors attenuate the danger to national security:

- The U.S. economy is less "energy intensive" (defined as the fraction of every dollar of GDP spent on energy) than any other major mature market economy, and therefore can absorb price increases more easily.
- Because of technological innovation in energy use and advances in exploration, the historical trend in global energy prices has been downward, consistently defying forecasts.
- Even assuming upward price trends in the future, as energy prices increase, alternative sources of energy (such as shale oil) will become cost-effective at different points, thereby dampening further price increases for traditional sources.

5. *What are your recommendations for coordinating the Defense mission with Energy and Interior missions? If Congress were to establish a tri-agency Task Force to complete the program planning, would that fit with your vision?*

The Department of Defense would support a tri-agency Task Force and support the development of multi-agency plans. The task force could develop plans and roadmaps to assure rapid development of the resource and reduce the impediments and hurdles industry currently faces to develop the resources. The task force could streamline the federal processes related to environmental assessments, federal land usage, surface and underground shale retorting, shale oil upgrading and distribution.

6. *You testified that it is your mission to design new fuel specifications, perhaps for a dual-purpose fuel, and to qualify fuels conforming to these specifications. As we build an oil shale industry, do you see your qualifying program as having implications to the civilian sector? Would you outline the prospective steps to accomplish your mission?*

Original equipment manufacturers (OEM's) will have reluctance to certify the use of fuels from any non-petroleum resources until they are satisfied that the fuel is fit-for-purpose, does not cause any adverse performance or durability issues, and offer similar or better operational performance compared to conventional petroleum derived fuels. As the military uses equipment that is similar to some of the equipment the civil sector uses, the qualification and demonstration of the fuel in military hardware would allay concerns the OEM's would have. The military would work closely with OEM's during the evaluation, certification and demonstration phases

and the results should be available for them to help certify the use of the fuel in civilian equipment.

The fuel would be evaluated using standard laboratory tests to determine the physical and chemical characteristics and determine the differences compared to petroleum derived fuels. Fuels will be tested in reduced scale weapon system simulators and in subscale components. The fuels would be tested to assure compatibility with the materials of construction of vehicle fuel systems, and tested at the component level to assure performance, suitability and durability for testing in full-scale equipment. The fuel would be tested in army ground tactical vehicles, aircraft and ships to assure long term durability and performance and to achieve certification for continuous use by the OEM's. Weapon system documentation will be updated and as production increases the fuel use would be implemented at test bases. The initial bases will be monitored to collect long term use information and full implementation would progress as fuel supplies become available.

Mr. GIBBONS. Dr. Barna, thank you very much for your testimony. It is certainly a pleasure to have you with us today, and you have been very helpful.

We will turn now to Mr. Mark Maddox, the Principal Deputy Assistant Secretary, Office of Fossil Energy for the United States Department of Energy. Mr. Maddox, welcome. The floor is yours.

STATEMENT OF MARK MADDOX, PRINCIPAL DEPUTY ASSISTANT SECRETARY, OFFICE OF FOSSIL ENERGY, U.S. DEPARTMENT OF ENERGY

Mr. MADDOX. Thank you, Mr. Chairman, for this opportunity to testify on oil shale and its potential for increasing our Nation's energy security by mitigating our dependence on imported oil.

Our domestic shale oil resource of more than 300 billion barrels of recoverable oil could play a significant role in meeting the Nation's future demand for liquid fuels. With high oil and gas prices, industry has strong incentives to develop technologies that can bring shale oil and other non-conventional fuels into production on an economically and environmentally sound basis.

This Administration strongly supports efforts by the private sector that could result in adding shale oil to the Nation's energy portfolio, therefore strengthening energy security. The Nation's oil shale resource is concentrated in pockets in Utah, Colorado, and Wyoming, and 80 percent of the resource is owned by the Federal Government. The resource is so large, even if only partially developed, it could deliver 2 to 3 million barrels per day for decades.

But in order to tap this enormous energy resource, industry must develop economically and environmentally sound technologies, as we attempted to do after the oil interruptions and price shocks of the 1970s, when the Federal Government encouraged the development of oil shale and other unconventional domestic resources.

Those efforts were abandoned when both government and industry concluded that the world oil market could provide adequate supplies, reasonable prices, and sufficient excess capacity. Many current observers of the market, however, question whether that conclusion still holds today, or will hold again.

From the beginning in 2001, President Bush has emphasized the desirability of reducing our reliance on imported oil. The benefit of 2 to 3 million additional barrels per day of secure domestic oil from shale is obvious. If that oil were available today, it would reduce our dependence on imported oil by as much as 25 percent. Com-

bined with the Administration's other long-term programs to reduce oil demand growth, shale oil could have a powerful and beneficial effect on future oil import levels.

But there are numerous challenges to development, including the attitude of the public, business and investment considerations, and land access and usage, and environmental concerns. These challenges are surmountable, given a real commitment and close coordination among all the players, public and private, in the energy sector.

Unfortunately, the shale oil development work of 30 years ago left a legacy of uncertainty for industry and the public, particularly for people living in the centers of development. The affected areas enjoyed a boom period during development, followed by a devastating bust that has left them understandably wary.

Fortunately, it appears the citizens of these areas are ready to give oil shale another chance and support a new development effort, but only with more planning and support for infrastructure and development.

The oil industry today is finding most of its attractive investment opportunities overseas. But as conventional oil plays become more difficult and conventional oil production peaks, industry will again look to the development of higher-cost resources such as shale oil.

How long this process will take is an open question. The answer will depend on economics, and the economics will be determined by projected oil price trends, tax rates, resource access, royalty regulations, permitting requirements, and the receptivity of state and local populations to development.

Looking down the list, it is clear the Federal Government and state governments will have a large role to play in removing road blocks and encouraging private sector interest in shale oil development.

A key development concern will be the environmental impact of extracting oil from shale by using technologies to heat the rock, either above or below ground. Despite the significant research and development work conducted 20 to 30 years ago, the industry has not yet reached a consensus on the best technology to use.

Regardless of the process, shale oil operations will have some environmental impact, as does any industrial operation. As always, the job of everyone involved in development will be to ensure that the impact is minimal and acceptable.

Fortunately, we have a very successful model for the development of oil shale, through the production of over 1 million barrels per day of oil from Canada's Alberta oil sands, where production is expected to exceed 2 million barrels per day in eight years.

Many parallels exist between shale oil and oil sands technologies, markets, and economics. We cannot be certain that oil shale economics will parallel those of the Alberta tar sands. There are important physical differences between oil sands and oil shale, and the extraction technology for one cannot directly be transferred to the other.

But comparisons suggest that the domestic oil shale industry is in some ways similar to the Canadian oil sands industry of 30 years ago. As part of its energy security goal, the Department is committed to improve energy security by developing technologies

that foster a diverse supply of reliable, affordable, and environmentally sound energy, and improve our mix of energy options.

This prospect of adding 2 to 3 million barrels a day of secure domestic oil to our Nation's energy supply for decades to come demands our attention and our support. The Department will work to achieve this goal in support of the economic security of the United States, in line with our commitment to deliver results for the American taxpayer.

Mr. Chairman, this concludes my prepared statement. I will be happy to answer any questions from you and the Committee.

[The prepared statement of Mr. Maddox follows:]

Statement of Mark Maddox, Principal Deputy Assistant Secretary for Fossil Energy, U.S. Department of Energy

Mr. Chairman, Members of the Subcommittee, thank you for this opportunity to testify on oil shale and other non-conventional oils, and their potential role in elevating our Nation's energy security by mitigating our dependence on imported oil. U.S. energy security is important by virtue of the crucial role it plays in achieving economic security.

I would like to share with you today our thoughts on the oil shale resource in these areas—first, oil shale's magnitude and potential; then, the history of past unsuccessful attempts to develop it; and, finally, barriers to development as they exist today. In addition, I will compare the prospects for oil shale with the commercial development experience of another non-conventional resource, Alberta's vast oil sand resources.

Ensuring the present and future energy security of the United States is a primary goal of the Office of Fossil Energy, and we are committed to the President's goal of elevating our energy security through increased production of economic domestic resources. Domestic oil shale represents a resource of more than 300 billion recoverable barrels of oil and is a resource which, if economical, could play a significant role in meeting the Nation's needs for more liquid fuels over the next several decades.

We also have potential domestic sources of non-conventional liquid fuels such as the technologically mature but uneconomic Fischer-Tropsch coal liquefaction, recovery of stranded oil, undiscovered oil and other currently uneconomic resources. With high oil and gas prices, industry has strong incentives to develop technologies that will facilitate exploration of non-conventional domestic resources, and in fact there is evidence that they are doing so.

The Resource

The total U.S. oil shale resource is estimated to be 1.8 trillion barrels and is primarily concentrated in the Green River formation in northeastern Utah, northwestern Colorado, and southwestern Wyoming. Over 50% of the world's oil shale resources are in this area, 80% of which are owned by the Federal Government. It is estimated that over 400 billion barrels of oil equivalent exist in oil shale at concentrations greater than 30 gallons/ton. In 1980, the Office of Technology Assessment published An Assessment of Oil Shale Technologies, which estimated that between 189 and 315 billion barrels of oil would be recoverable from this high quality shale. Oil and Gas Journal, in its August 9th 2004 issue, suggested that 100 billion barrels of oil from domestic oil shale could be reclassified as proven reserves if the technology became commercially viable. Suffice it to say, if it were financially feasible to even partially develop, the resource could sustain an industry of 2-3 million barrels per day for decades.

The factors that limit the development of oil shale have nothing to do with the potential quantity of the resource. Historically, oil shale production hasn't been economical. The cost of production has been too high compared to the cost of producing from conventional resources. This problem has been compounded by the need to build an infrastructure to support oil shale and the cost of disposal of byproducts. Although the Federal Government attempted to make oil shale economical in the late 1970's and early 1980's, this effort was abandoned because shale oil production could not be sustained in the face of abundant and cheap conventional crude oil. This was true even though the Government embarked on this effort at a time when oil prices were higher in real terms than they are today. The failure of the Government's efforts in the 1980's was not due to the failure of the resource, the technology, or environmental problems; economically it was simply too expensive.

Recently, however, industry has shown renewed interest and has begun committing resources.

What is the Commercial History of Oil Shale in the United States?

After the oil interruptions and price shocks of 1973-74, the Federal Government encouraged the development of unconventional domestic resources including oil shale. The Department of the Interior offered commercial leases for development in 1973. Bonus bids totaled $450 million for four oil shale leases and industry began development. Economic incentives were later offered for oil shale development including a guaranteed price floor ($42.50 indexed to the CPI), and a production tax credit of $3 per barrel. In total we estimate $5 billion was invested in oil shale facilities beginning roughly in 1975. Major players at that time included Exxon, Shell, Mobil, Occidental, Atlantic Richfield, Chevron, and Unocal. In the early 1980's these projects began to close and the last closed in 1992.

The consensus of the industry was that oil prices simply did not stay on a price path over the long term that would assure a reasonable return on investment for an unconventional crude oil. In addition, policy changes accompanying new administrations removed the subsidies for synthetic fuels. Witness the demise of the Synthetic Fuels Corporation, which was chartered during the Carter Administration but allowed to expire during the Reagan Administration. The oil price collapse of 1986 assured the end of the U.S. synthetic fuels industry.

The general impression left following the demise of the U.S. oil shale industry was very negative. During the boom period, the influx of workers into Western Colorado strained and ultimately overwhelmed the local infrastructure and housing, producing lasting socioeconomic effects. When the industry collapsed, the local towns were left with infrastructure in excess to their needs, shrunken property values and a tax base incapable of supporting the infrastructure.

How is Oil Produced from Oil Shale?

Kerogen, a low grade form of immature oil, is extracted from oil shale in a process called "retorting", which requires heating of the rock to about 900 degrees Fahrenheit. Two generic methods of retorting have been developed:

- In situ: This method leaves the rock in place and injects a heat source that releases the oil from the kerogen. The shale oil then flows to a well and is pumped to the surface. The source of the heat is a technical issue still open to research and testing. The only active pilot project in the U.S., owned by Shell Oil, is using down hole electric resistance heaters, but optional technologies involve steam, microwaves, and fire.
- Surface retorting: This technology depends upon mined ore for a feedstock. The ore can be either surface mined or mined underground. The ore is brought to the surface, crushed and placed into a retort. The shale oil is removed and the spent shale sent for disposal. The shale oil is upgraded by the addition of hydrogen and then is conventionally refined to produce finished products. Several different retort designs have been constructed and tested in the United States as a part of earlier development efforts. However, there are currently no commercial surface retorts in the U.S. processing oil shale.

Challenges to Commercialization

Perceived Risk: Shale oil activities in the late 1970s and early 1980s have left a legacy of uncertainty. Members of industry and the citizenry alike are uncertain about the risks associated with commercial development.

Current Oil Industry Economics: U.S. domestic oil production is high cost compared to many parts of the world because our fields are mature and declining. Private investment dollars are directed to the most economic areas where costs of production are low, like West Africa, Brazil, the Middle East, Russia and Central Asia. As long as current geopolitical and market conditions persist, we expect more money to flow to energy extraction on a world wide basis; however, not a large share of it is expected to be invested in the United States in the immediate future. As conventional oil plays become more difficult to find, and as conventional domestic oil production peaks, industry will again begin to focus on the development of the resources that can be extracted profitably at higher prices, including oil shale.

Prospects for commercial oil shale production will depend on the private sector's perception of the relative profitability of oil shale versus competing resources. Factors that will determine economics are projected oil price trends, tax rates, cost of production, resource access, royalty payments, permitting requirements, cost of byproduct disposal, and the willingness of the State and local populations to host a new industry.

The size of the industry will be limited by existing distribution, pipeline capacity, water availability, power distribution, and refining capacity in this region of the

Rocky Mountains. If the oil shale industry develops to any appreciable size, investments will be required to expand the limited infrastructure.

Land Access and Usage: A major driver of shale oil extraction economics is the concentration of the resource. Movement of ore to the retort can be very expensive, because the ore is mostly rock with only a little oil (more than one ton of ore per barrel of oil). Therefore, the ore must be processed at or near the geologic formation where it is found. While the natural resource is very concentrated in Colorado, Utah and Wyoming, the ownership is not. The Federal Government owns 80 percent of the resource base, and the remaining tracts are broken up. At this time the Department of the Interior does not have a commercial leasing program, although it recently established a leasing process for small tracts to conduct research, development, and demonstration projects and is accepting nominations from industry for parcels to be leased.

Environmental Impact: The environmental impacts of shale oil development are significant. Like the resource, they will primarily be concentrated in small geographic locations. Because oil shale is mined, there are surface impacts. Oil shale production is water intensive, which is an important limited resource in the regions with oil shale deposits. Because the retorting processes are energy intensive, there are combustion emissions in areas where the air is currently very clean. The mining or in situ technologies may also disturb the local water tables. In the case of the in situ technology, the spent shale in place may contain toxins that need to be kept away from ground water. In the case of surface retorting, the spent shale, processing water, and other byproducts must be disposed of in a safe manner. How to do that on a massive scale has not been defined. To produce a million barrels of oil would require disposal of more than a million tons of byproducts.

The positive aspect of the resource is that its density is so great that most of the environmental impacts can be restricted to a relatively small area within two or three States. However, because shale oil production is energy intensive, the industry could add significantly to green house gas emissions during production. Similarly, greenhouse gas emissions will be released when the fuel is consumed.

Extraction Technology: Despite the significant research and development conducted 20-30 years ago, there is no accepted benchmark for the best technology to use. Furthermore, because of modern developments in environmental protection and resource conservation, it will be important for the existing technologies to improve from an efficiency, and environmental impacts perspective. Companies will have to advance extraction technologies through research, development, and demonstration.

Comparison with Alberta Oil Sand Commercialization

Commercial production from formerly uneconomical resources occurs as markets change and drive technology development. Oil from Alberta oil sand, once considered to be an unconventional resource, is being commercially produced today. Oil was first produced at a commercial scale from Alberta oil sand more than 35 years ago. Today, oil sand production is over one million barrels per day and is expected to exceed 2 million barrels per day within the next eight years. A strong partnership between government and industry stimulated more than $65 billion in private investment to accelerate development and achieve industry scale operations during this decade.

Like oil sands, U.S. oil shale is rich, accessible, geographically concentrated, and well defined. However, the technologies required for exploitation of oil shale are very different from those required for oil sands. The richness of the respective resources are similar, with oil sands yielding approximately 25 gallons per ton of bitumen while some oil shale deposits yield an average of about 30 gallons per ton. A comparison of the qualities of the two oils shows them to produce a similar product after processing. The Athabasca sand produces 34 degree API oil and the oil shale produces 38 degree API oil. However, there are important physical differences between oil sands and oil shale and the extraction technology for one cannot directly be transferred to the other.

Summary

In summary, we need to examine all of our resource bases if we are to do a credible job in protecting the United States' energy security interests. As part of its energy security goal, the Department is committed to improving energy security by developing technologies that foster a diverse supply of reliable, affordable, and environmentally sound energy and improve our mix of energy options. The Department will work to achieve this goal in support of the economic security of the United States, in line with our commitment to deliver results for the American taxpayer. Mr. Chairman, and members of the Subcommittee, this concludes my prepared statement. I will be happy to answer any questions you may have at this time.

Response to questions submitted for the record by Mark Maddox, Principal Deputy Assistant Secretary for Fossil Energy, U.S. Department of Energy

Ensuring Oil Shale Production

Question 1. What are the three most important things that the Federal Government can do to ensure timely production of large volumes of oil from oil shale?

Answer 1. It is most important to make land available for oil shale research and, eventually, the production of oil shale. The first step in this area is progressing as the Bureau of Land Management is currently accepting nominations of parcels for a potential research and development scale leasing program.

Economical Analysis

Question 2. Your written testimony stated that U.S. oil shale resources contain at least 300 billion barrels of recoverable oil IF ECONOMICAL. Has the Department of Energy performed an analysis of whether production of oil shale is ECONOMICAL at this time? If you have not performed such an analysis, when do you plan to do so?

Answer 2. We have performed an analysis of the economics of oil shale. As part of our analysis of the industry we have developed a model to evaluate project economics for the application of oil shale technologies to selected resource tracts, and the relative impact of various incentives on project economics.

As there are no commercial oil shale facilities operating in the United States, our analysis cannot be based on realized costs from any such current operations. Several oil shale projects were undertaken domestically in the 1970s and 1980s, most notably Unocal's operations in Parachute Creek, Colorado. However, we have no direct information on the costs these operations experienced. Some indirect evidence comes from the fact that Unocal ultimately determined its operations to be uneconomical, despite receiving a guaranteed price of $41.50 per barrel under a long-term supply contract reached in 1981 with the Department of Defense. Converting from 1981 dollars, this guaranteed price would correspond to more than $80 per barrel in 2005.

In the absence of data on realized costs, our analysis is based primarily on engineering models developed in the 1970s in conjunction with the 1974 Prototype Oil Shale Leasing Program (POSLP). These models provide capital cost and production cost estimates for various technologies, which we have escalated to 2004 dollars using Bureau of Labor Statistics data and have further validated with current vendor quotes. The analysis also applies resource characterization data from surveys conducted by the U.S. Geological Survey (USGS) in preparation for the POSLP. The economic analysis examined the USGS defined resource tracts to determine the most efficient technology for resource extraction at each location. The production cost estimates and resource characterization data were then used to calculate minimum economic prices.

We define the minimum economic price as the break even price for a mature industry, one that has already recovered substantial initial costs (associated with research and development, permitting and land access) and has achieved substantial cost reductions through learning-by-doing. If we were to include estimates of these initial costs and the likely inefficiency of early plants into our calculation of minimum economic prices, the figures listed in the table below could more than double.

Our model estimates cash flow for the various projects by evaluating plant capacity, development schedule, market prices for oil and natural gas, leasing royalty structure, operating costs, capital costs, and tax structure. The table below summarizes the model results for the four known extraction technologies. The average minimum economic cost shown in the table below represents the average of the break-even prices for a given technology across the resource tracts where it is being applied. Capital costs are the sum of investments needed per barrel of installed capacity. These costs include investments in mining, retorting, solid waste disposal, refining and upgrading, plant utilities, and other facilities. Operating costs include fuel, operating and maintenance personnel, consumable equipment and other non-capital costs for mining, retorting, refining and upgrading. The components of both capital and operating costs are different for various technologies used for mining, retorting, and upgrading.

Technology	Number of Tracts	Average Minimum Economic Price ($/Bbl)	Capital Costs (K$/SDB)	Operating Costs ($/Bbl)
Surface Mining	7	$44.24	40$ - 41$	12$ - 13$
Underground Mining	7	$61.81	41$ - 62$	16$ - 17$
Modified In-Situ	7	$65.21	27$ - 40$	18$ - 26$
True In-Siitu	4	$37.75	36$ - 56$	19$ - 20$

Reclassification of Proven Reserves

Question 3. Am I correct that when that analysis has been completed, and assuming that the analysis shows that production of oil from oil shale is economical, large quantities of domestic oil shale resources could be reclassified as proven reserves? Wasn't this confirmed by the Oil and Gas Journal in its August 9, 2004 issue?

Answer 3. No. The classification of proved oil and gas reserves is regulated by the Securities and Exchange Commission. Proved reserves are defined in Rule 4-10(a) of Regulation S-X of the Securities Exchange Act of 1934.

> "Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and 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, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided by contractual arrangements, but not on escalations based upon future conditions.
>
> "Existing economic and operating conditions are the product prices, operating costs, production methods, recovery techniques, transportation and marketing arrangements, ownership and/or entitlement terms and regulatory requirements that are extant on the date of the estimate."

As the rule indicates, the resource needs to be under development with commercially proven technologies to be classified as a proved reserve. In addition, Rule 4-10(d) of the same law explicitly prohibits oil from oil shale (along with coal and gilsonite) as being classified as a proved oil and gas reserve. This prohibition is based largely on economic uncertainties, including the lack of existing markets. The rule leaves open the possibility of classifying these types of resources as proved reserves if markets develop and companies demonstrate commitment to develop the necessary production. However, the SEC currently treats oil shale development as a mining activity. The classification of proved reserves of ore for mining activities is regulated by SEC Industry Guide 7 and it appears that the geologic analyses conducted by the USGS would be sufficient to recharacterize the oil shale resources as proved reserves, if they were developed.

As a comparison, the Alberta oil sands resource is estimated to total well over 1 trillion barrels. It was only in 2004, however, that 174 billion barrels were finally reclassified as proved reserves, this coming after over 40 years of work developing the resource. Again, this is because, as with U.S. law, Canadian law requires that the resources be developed, that commercially viable production be demonstrated, and that economic conditions support the long-term exploitation of the resource.

EIA Reserves Estimate

Question 4. On April 12, you testified before the Senate Committee on Energy and Natural Resources that "our domestic total oil shale resource is more than 1.8 trillion barrels, with perhaps 100 billion to 200 billion barrels commercially viable." Based on this position, when will the Energy Information Agency take action to recharacterize that amount of resource as reserves?

Answer 4. The Energy Information Administration (EIA) currently recognizes a very small part of the nation's oil shale resource as proved reserves as does the Securities and Exchange Commission (SEC). These oil shale reserves, unlike those discussed in my testimony, meet the definition of proved reserves—they are developed or are being developed and they are economic with current prices and existing technology.

While SEC rules state that oil shale (along with coal and gilsonite) should not generally be classified as a proved oil and gas reserve, it leaves open the possibility of doing so if markets develop and companies demonstrate commitment to develop

the necessary production. For example, the SEC and EIA have both recognized large amounts of coalbed methane as proved gas reserves. EIA will recognize a larger portion of the oil shale resource base as proved reserves when and if it is developed and meets the definition for proved reserves.

Environmental Impact

Question 5. Your testimony stated "it will be important for existing technologies to improve from an efficiency, and environmental impacts perspective." You also state that "the environmental impacts of shale oil development are significant." How can DOE make these statements if it has not performed an environmental impact statement on oil shale production? Isn't it possible that the impacts could be mitigated to a point where they might not be "significant"?

Answer 5. As there has never been a full-scale operational oil shale development in the United States, there need to be technological advances to improve the effectiveness and efficiency of the industry. The environmental impacts are no greater than other very large industrial developments, such coal mining and petroleum refining operations, but they are significant. These are very large mineral extraction and upgrading operations, with all of the environmental issues and problems associated with that kind of development. Due to the significant amount of energy currently required to extract a useful product from oil shale, it is also likely that net greenhouse gas emissions from oil shale production will exceed that of conventional fuels.

Greenhouse Gases

Question 6. You also stated that "greenhouse gas emissions will be released when the fuel (shale oil) is consumed." How would these emissions be different from consumption of conventional oil?

Answer 6. In assessing the overall greenhouse gas impact of oil shale, it is necessary to look at the complete production/consumption cycle. Oil shale production—whether through surface retorting or an in situ process—is substantially more energy-intensive than conventional oil production. Assuming fossil fuels are used to provide the energy input for oil shale production, the net greenhouse gas impact of developing oil shale resources is likely to be substantially higher than the per-unit impact of convention oil production. The production of greenhouse gasses will vary by the technology employed. The use of low temperature conversion in in situ processes will reduce greenhouse gas emissions.

For most surface retorting operations the level of green house gases released from the ground during development, will likely be very similar to emissions resulting from the production of conventional oil. It should be noted, however, that very high temperature retorting processes (i.e. direct combustion) could generate higher amounts of carbon dioxide. Western oil shales are rich in carbonate compounds, which when combusted will release carbon dioxide. It is likely the application of indirect heat and slower heating rates, as are currently being employed in small operations, will help minimize these increased carbon dioxide emissions. Elevated carbon dioxide emissions are not anticipated from in situ production. Again, the rate of heating and the low temperatures (relative to direct combustion) avoid conversion of carbonate compounds to carbon dioxide.

The liquid fuels produced from western shale oil will be low in sulfur and rich in hydrogen that when consumed will produce less carbon dioxide per unit of energy than conventional fuels.

Energy Requirements

Question 7. One of the issues sometimes raised is one of energy requirements for producing oil shale, which is central to sustainability. Does your agency have any analysis of energy requirements? What needs to be done to reduce the energy costs of production?

Answer 7. How much energy is consumed in the production of energy is usually described as the energy balance. The oil shale industry has often been criticized for consuming large amounts of energy in the manufacture of the output energy. Shell Oil reports that in their ICP In situ process they consume 1 Btu for every 3 Btu's of energy produced. This "energy balance" is substantially lower than for many other fuel sources. However, the utilization of natural gas produced during the ICP in situ process doubles the energy efficiency to 6 btu's of energy produced for each btu consumed. One of industry's primary goals is to increase this energy balance, which would both improve the economics of oil shale production and reduce its environmental impact, particularly in terms of net greenhouse gas emissions. There are

also opportunities to improve energy balances once pilot and demonstration plants are running.

Task Force

Question 8. How do you propose that DOE engage industry, local communities and other stakeholders in program planning efforts? Would you support the tri-agency Task Force concept advanced by Senator Hatch?

Answer 8. The Budget does not include funds for an oil shale program and the Administration isn't pursuing a new program promoting the development of oil shale.

Mr. GIBBONS. Thank you very much, Secretary Maddox. Again, your testimony is very helpful to the Committee, and we certainly appreciate your presence here before us today.

We will turn now to Mr. Chad Calvert, Deputy Assistant Secretary, Land and Minerals Management, U.S. Department of the Interior. Secretary Calvert, welcome back to the Committee once again. It is a pleasure to see you before us, and the floor is yours.

STATEMENT OF CHAD CALVERT, DEPUTY ASSISTANT SECRETARY, LAND AND MINERALS MANAGEMENT, U.S. DEPARTMENT OF THE INTERIOR

Mr. CALVERT. Thank you, Mr. Chairman. I appreciate having the opportunity to testify today on behalf of the Department of the Interior and the Bureau of Land Management, which is a part of Land and Minerals Management at the Department.

Let me start out by saying that the Secretary has taken a real interest in the issue, and she recognizes that we are at a very unique time, with oil around $60 a barrel and technology evolving across the world for development of oil shale. She recently visited eastern Utah and western Colorado and actually went out and looked at some of the development that is going on on private lands there; and was very encouraged by the technology and the development of it; and has encouraged BLM to move forward as quickly as they can to develop commercial leasing.

I will speak about BLM's role here as the land manager, the land and resource manager, and our responsibility to manage public lands for multiple use; which includes, of course, the development of oil shale.

On Federal lands in Wyoming, Utah, and Colorado, we have roughly 72 percent of the surface oil shale reserve, and as much as 82 percent of the Nation's reserve in those three states on Federal land.

The BLM currently has no commercial leasing regs. They developed drafted regs in the 1980s in response to high prices. And after the 1974 oil shale prototype program had begun, BLM decided, in roughly '83, not to complete those regs, because technology and prices just weren't keeping up with enabling development of oil shale, and they abandoned the regulatory process at that time. And there has been no industry interest in redeveloping regs since the early '80s, until now.

Currently, the President's national energy policy outlined recommendations for the BLM to diversify and increase energy supplies, which included development of oil shale. BLM developed a plan containing 54 discrete tasks designed to implement the

President's directives. And one of those was to establish an Oil Shale Task Force to develop recommendations for the BLM on how we should move forward.

The Oil Shale Task Force was designed to address four points: how to access unconventional resources on public lands; to identify impediments to oil shale development; to coordinate and combine for public land managers what industry interest was in research and development of commercial opportunities on public lands; and to provide Secretarial options to enable us to capitalize on the opportunities. The task force has a draft report which is being finalized and, hopefully, we can provide to this Committee expeditiously.

On November 22, 2004, BLM, on a recommendation from the task force, proposed an oil shale lease form and a request for information to solicit comments on an initial oil shale leasing program. Ninety percent of the comments were favorable to developing a research, development, and demonstration program.

On June 9th, just roughly three weeks ago, we finalized regulations in the "Federal Register," requesting nominations for RD&D—which is research, development, and demonstration activities—and requested industry to supply or to nominate potential research parcels within the next 90 days, until September 7th.

This program would allow tracts of land up to 160 acres to be used to demonstrate the feasibility of technologies. The lease terms would be ten years, with an option to extend for five years on a showing of diligence of research. Royalties would be waived during the lease, and rentals would be waived for the first five years.

Applicants would also at the time of the nomination be able to identify an additional 4,960 acres that they would have a preferential right to lease, on the showing of commercial development on the 160-acre lease.

One of the principal reasons we decided to move forward with the RD&D lease program was because we really lacked the ability to do more extensive or comprehensive NEPA on technologies that we didn't know would be utilized in areas that we didn't know would be located. And we decided that it was better to move forward with small scale; determine what could be done using an environmental assessment tiered to the land-use plan; and then, based on what was developed as part of that 160-acre lease, move forward with additional NEPA in the future that would enable commercial development in a way that was appropriately covered by the National Environmental Policy Act.

I will close by saying we are committed to developing a commercial leasing program, and we believe that what we have proposed is the best way to go about doing that. Thank you, Mr. Chairman.

[The prepared statement of Mr. Calvert follows:]

Statement of Chad Calvert, Deputy Assistant Secretary for Land and Minerals Management, United States Department of the Interior

Mr. Chairman and Members of the Committee, thank you for the opportunity to appear here today to discuss the Bureau of Land Management's (BLM) efforts to facilitate and promote oil shale research and development on public lands.

America faces an energy challenge. As recently as April 5, 2005, Federal Reserve Chairman Alan Greenspan commented extensively on this challenge. He stated,

> "Markets for oil and natural gas have been subject to a degree of strain over the past year not experienced for a generation. Increased demand and

lagging additions to productive capacity have combined to absorb a significant amount of the slack in energy markets that was essential in containing energy prices between 1985 and 2000."

For a considerable time, many have believed that oil shale, if economic, has the potential to be a major source of domestic energy production, especially since it is suited for refinement as jet fuel for the military and the airline industry. Recently, the BLM, which has the authority to issue leases for oil shale under the Mineral Leasing Act and to receive rental payments and royalties, has received expressions of interest from industry for conducting research and development projects on public lands in the Green River Formation in the tri-state area of Colorado, Utah and Wyoming. It is BLM's hope that renewed interest in oil shale research and development efforts will lead to environmentally responsible ways of unlocking the vast oil shale resources contained in the United States, and presents a potential means of helping to reduce the imbalance in domestic energy consumption and production that currently exists in this country.

Background

Oil shale is a type of rock formation that contains large concentrations of combustible organic matter. When processed, oil shale can yield significant quantities of shale oil. Various methods of processing oil shale to remove the oil have been developed. A common element among those methods is the use of heat to separate out the oil from the rock.

The United States has significant oil shale resources, primarily within the Green River Formation in Wyoming, Utah and Colorado. These oil shale resources underlie a total area of 16,000 square miles and represent the largest known concentration of oil shale in the world. Federal lands comprise roughly 72% of the total oil shale acreage in the Green River Formation.

In the latter years of World War II, several tests were conducted to determine the economic viability of oil shale extraction technologies. However, in the years following World War II, petroleum producers looked to more easily accessible and economically viable supplies and interest in oil shale extraction declined. More recently, during the mid 1970s through the late 1980s, the Department of the Interior and the BLM made oil shale resources on public lands available through the Oil Shale Prototype Program, which was designed to allow companies to develop and refine the technology for extracting oil from oil shale. Additionally, in the 1980's, the U.S. Geological Survey (USGS) had an active oil shale mapping program, which mapped the major oil shale fields of the United States and conducted geological research on the Green River deposits. The USGS also conducted mineralogical and geochemical studies aimed toward characterizing oil shale for the commercialization of this resource.

Precipitated by the oil price spikes of the early 1970s, companies showed significant interest in exploring domestic oil shale development. Previous oil shale research showed that it was possible to extract shale oil from the rock; however, despite government subsidies, the extraction process was energy-intensive and costly. Through a series of experiments, industry attempted to find more effective ways to extract shale oil from oil shale rock, but the easing and subsequent collapse in petroleum prices led the companies to conclude that production was not economically viable. The participants in the Oil Shale Prototype Program withdrew from their research efforts before the BLM could promulgate permanent regulations for oil shale leasing and operation.

Most USGS activities related to this commodity have also diminished significantly. However, since the latter half of the 1980s, the USGS has maintained a small effort in oil shale studies, both domestically and abroad, which included evaluation of world oil shale resources and a cooperative effort funded by the Department of Energy to create a National Oil Shale Database, in which shale oil analyses and other data were entered and compiled. With the recognition that oil shale is a potentially important domestic fossil energy resource, the USGS has continued in these efforts to the present day. Although no comprehensive oil shale assessment has been done, the USGS has completed oil shale resource studies on some of the most promising areas. One example of this is "Thickness, oil-yield, and kriged resource estimates for the Eocene Green River Formation, Piceance Creek basin, Colorado" USGS Oil and Gas Investigations Chart OC-132. Another example is USGS Open-File Report 91-0285 "Oil-Shale Resources of the Mahogany Zone in eastern Uinta Basin, Uintah County, Utah." USGS is currently working with the State of Utah to evaluate all oil shale lands in the eastern Uinta Basin, compiling, among other things, geologic maps, cross sections, geophysical and lithologic logs, and drill hole information.

Elsewhere in the world, efforts continue to harness oil shale resources. For example, in Gladstone, Queensland, Australia, there is a large-scale demonstration project where, from June 2001 through March 2003, 703,000 barrels of oil, 62,860 barrels of light fuel oil, and 88,040 barrels of ultra-low sulphur naphtha were produced from oil shale. In January 2003 alone, the operation produced 79,000 barrels of oil. Significant oil shale reserves also exist in the Republic of Estonia, where active oil shale deposits amount to about 9.2 billion barrels of oil.

Current BLM Efforts

The President's National Energy Policy outlined a number of recommendations to diversify and increase energy supplies, encourage conservation, and ensure environmentally responsible production and distribution of energy. In response, the BLM developed a plan containing 54 tasks designed to implement the President's directives, including efforts to promote the development of oil shale resources on the public lands. To carry out this task in an environmentally responsible manner, and in keeping with our multiple-use mandate, the BLM established its own Oil Shale Task Force.

The Oil Shale Task Force was established to address: 1) access to unconventional resources (such as oil shale) on public lands; 2) impediments to oil shale development on public lands; 3) industry interest in research and development and commercial development opportunities on the public lands; and; 4) Secretarial options to capitalize on the opportunities. The Task Force has prepared a report concerning the development of oil shale resources on Federal lands in order to determine whether technological advances have reached the point where it is possible to develop those resources economically and in an environmentally responsible manner.

On November 22, 2004, the BLM published a proposed oil shale lease form and request for information in the Federal Register to solicit comments and suggestions from interested parties about the design of the oil shale leasing program. The report recommendations and BLM's analysis of the responsive comments to the Federal Register notice led to the design of an Oil Shale Research, Development and Demonstration (RD&D) program.

BLM published a new, final oil shale lease form in the Federal Register on June 9, 2005, and invited interested parties, from June 9, 2005 through September 7, 2005, to nominate public lands for oil shale RD&D activities. The nominations must be accompanied by a non-refundable application fee of $2,000. The RD&D lease program design allows tracts of land up to 160 acres to be used to demonstrate the economic feasibility of today's technologies over a lease term of ten years, with the option for an extension of up to five years. The payment of royalties will be waived during the RD&D lease, payment of rental will be waived for the first 5 years of the RD&D lease, and an applicant may identify up to an additional contiguous 4960 acres that it requests be reserved for a preference right commercial lease should RD&D efforts prove successful in demonstrating the economic feasibility of oil shale production.

One of the principal reasons to offer small RD&D leases before issuing commercial leases for oil shale is to obtain a better understanding of the environmental effects of the new technologies and the effectiveness of various mitigation measures. Consequently, given the small scale of the RD&D leases, BLM has determined that for environmental review under NEPA, site-specific environmental assessments (EAs) would be more appropriate than a programmatic environmental impact statement (EIS) document. The complexity of the analysis required for the RD&D lease will depend on the location, the type of project proposed, and the type of technology to be used.

Conclusion

Thank you for the opportunity to testify today about the BLM's Oil Shale Development efforts. I would be happy to answer any questions you have.

Response to questions submitted for the record by the Bureau of Land Management, U.S. Department of the Interior

1. *Question: What are the three most important things that the Federal Government can do to ensure timely production of large volumes of oil from oil shale?*

Answer: The Department of the Interior believes three things must happen before commercial oil shale production will take place: 1) oil shale resources must be made available for research and development of extractive technologies; 2) extractive technology must be improved to increase efficiencies while minimizing environmental impacts, and 3) a market for oil shale end products must develop.

The Department of the Interior's Bureau of Land Management (BLM) has taken the first step by making Federal oil shale resources available through the BLM's recently-created Research, Development and Demonstration (R,D&D) leasing program. In addition, the BLM will promulgate permanent leasing regulations in accordance with the recently-signed energy bill.

The BLM's R,D&D leasing program makes it possible for interested parties to proceed with the second step of improving extractive technologies. In light of current market prices for crude oil, private companies should have ample incentive to conduct R,D&D and improve their oil shale technology.

The final step, development of a market for the end products, will ultimately depend on the economic viability of oil shale.

2. *Question: On April 12, 2005, Mr. Tom Lonnie from the BLM testified before the Senate Committee on Energy and Natural Resources that BLM has not examined the Canadian program that has led to the production of large quantities of oil from oil sands. When will the Department conduct an analysis to learn the significant features that made their program a success?*

Answer: The BLM intends to examine and evaluate the Canadian experience and process to see if there are lessons we can learn and apply to our unconventional resource development efforts. However, it is important to note that oil sands and oil shale are distant resource cousins and there are vastly different economic and technological challenges associated with developing these resources. Any formal analysis of the Canadian oil sands program is beyond the mission of DOI.

3. *Question: Your testimony mentioned the June 9 Federal Register notice on RD&D leasing. The Subcommittee will present questions to you about this leasing proposal to be answered as part of the record. Generally, we have some concern about the lack of specificity about several very important aspects such as the price for companies to receive a commercial lease on the preference right acreage, the royalty and regulatory schemes that will apply to production and activities on the leases, and other important provisions. Could you provide more details NOW on these items?*

Answer: The BLM expects to develop a methodology for determining fair market value for bonus bids to convert a R,D&D lease to a commercial lease, including any preference right acreage. However, the data currently available on oil shale that could be used to determine fair market value is very limited and unreliable. Also, the R,D&D program is designed to allow the demonstration of new technology where the economics are not fully understood at this time. What is known at this time is that conversion would be based on the ability of the lessee to produce commercial quantities of shale oil from the lease, documentation of consultation with state and local governments on the mitigation of socio-economic impacts, and the BLM's determination, following NEPA analysis, that the environmental consequences of developing the preference right area are acceptable.

The BLM expects to gather more reliable data from the R,D&D leases. The Secretary has the authority under the Mineral Leasing Act to establish royalty rates, and plans to do so prior to the commencement of commercial production. The goal of the BLM is to promulgate final commercial leasing regulations prior to the conversion of R,D&D leases to commercial leases, incorporating the establishment of royalty rates as an integral aspect of the final rulemaking

4. *Question: Would you agree that the 5120 acre limit and the one lease per lessee restriction of the Mineral Lease Act of 1920 are impediments to commercialization of oil shale? Would you agree that removing these restrictions would be an important step toward commercialization?*

Answer: The BLM is aware of assertions that the 5120 acre limit could constitute an impediment to commercial oil shale development. However, with the enactment of H.R. 6, the Energy Policy Act of 2005, the per 5120 acre limit has been increased to 5760 acres and the number of acres a lessee may hold in any one state has been increased from 7680 acres to 50,000 acres. These changes should have a positive impact on commercialization efforts. However, until oil shale development proves to be economic and moves beyond the RD&D phase, these limitations should have little practical impact on commercialization efforts.

5. *Question: In Utah, and possibly Wyoming, prospective developers now need to deal with more than one agency to put together a logical development unit? Would land exchanges designed to block up logical development units help solve this impediment?*

Answer: Oil shale deposits, like other natural resources, occur on Federal, State, Indian, and private lands. As a result, developers may need to deal with more than

one agency to assemble a logical development unit It should be noted, however, that through Section 369(n) of the recently-enacted Energy Policy Act of 2005, Congress has directed the Secretary to consider using land exchanges where appropriate and feasible to consolidate land ownership and mineral interests into manageable areas. This provision directs the Secretary to identify public lands containing oil shale or tar sands deposits within the Green River, Piceance Creek, Uintah and Washakie geologic basins and to give priority to implementing land exchanges within these basins.

6. *Question: You testified that the BLM owns about 72% of the Resource acreage, with the remaining acreage is held by non-federal interests. Holders of these other 28% may wish to nominate federal lands under your recent Call for Nominations—Oil Shale Research, Development and Demonstration (R, D, and D) Program contiguous to their non-federal holdings. Is there anything in your process that would prohibit a holder of non-federal lands from conducting their R, D and D activities on non-federal lands and qualify the nominated BLM property for conversion (subject to the conversion requirements in your regulations) at a later date? It would appear that cases like this would improve the likelihood of commercialization, which is the goal. Do you agree?*

Answer: The process established by the BLM does not prohibit those conducting oil shale research and development on private lands from applying for a Federal lease. The criteria for nominating and qualifying for a preference right lease are set forth in the June 9, 2005, Federal Register notice. In order to qualify for conversion, the applicant would need to produce shale oil in commercial quantities from the Federal lease before its expiration.

7. *Question: You testified that NEPA requirements are a reason why progress has been slowed in preparing lease regulations. Uncertain permitting timelines also put investment at risk, and are an impediment to investment. Do you have any suggestions for Congress to mitigate these impediments? For example, if Congress were to supply the financial resources for BLM to work with applicants to assure that applications are complete upon first submittal, would that help? Can Congress help eliminate indefinite delays by placing limitations on timeframes for protests? What about reducing or eliminating NEPA requirements below a certain impact level?*

Answer: Conducting NEPA analysis does take time. In complicated projects, Federal law also brings into play numerous other environmental statutes, such as the Endangered Species Act, the Clean Air Act, the National Historic Preservation Act, etc. We note that the Energy Bill contains a provision in Section 369(k) that designates the Department of the Interior as the lead Federal agency for coordinating applicable Federal authorizations and environmental reviews and directs the Secretary to issue regulations necessary to implement this provision within six months of enactment.

The immediate challenge for the oil shale program is that it is unclear what the proposed actions of commercial leasing would be, given that we do not yet have proposals for commercial projects. For this reason, and at this time, BLM would prefer to conduct site-specific NEPA analysis instead of doing a regional programmatic environmental impact statement (EIS) document.

One of the principal reasons to offer small research and development leases before issuing commercial leases for oil shale is to obtain a better understanding of the environmental effects of the new technologies and the effectiveness of various mitigation measures. As stated in the call for nominations, the complexity of the analysis required for the R,D&D lease will depend on the location, the type of project proposed, and the type of technology to be used. It is anticipated that more intensive NEPA analysis will be performed before the award of a preference right lease, using information generated during the R,D&D phase. Approval of conversion to a commercial lease would then also depend on a determination that a commercial operation on the acreage selected could be conducted in an environmentally acceptable manner.

The BLM works closely with industry to ensure that the required information is provided prior to the submittal of any application for a use authorization. This helps to eliminate potential delays due to incomplete applications. In addition, the BLM is performing full and meaningful consultation with the public, particularly with local individuals through the land use planning process and other project-specific NEPA analysis. The BLM is also working on creating more effective governmental partnerships, through the lead agency-cooperating agency relationship and its application to the planning and associated environmental assessment responsibilities. This will help the BLM to work together and foster a commitment by local, tribal,

and state governments and other Federal agencies to recognize common goals and achieve balanced resource management.

The BLM has existing authority to limit protest periods, and this is among the options the BLM will be considering in drafting the final commercial leasing regulations. However, there are pros and cons to limiting protest periods, and BLM will need to weigh both in making any final decision to impose such limitations.

8. *Question: Mr. Calvert, it is my understanding that Shell's in situ conversion process, even though based on heating the ore underground, involves nearly 100% surface disturbance, removing all vegetation and disturbing the soil. If BLM approves a plan to allow this, how would DOI ensure that the inevitable and significant damage to the land be reduced so that others would be able to use the land after mining is through?*

Answer: The BLM anticipates that the proposed R,D&D program will include some level of surface disturbance, regardless of the methodology employed. The in situ conversion process involves drilling vertical holes, as is done in oil and gas recovery, but does not have any mining component. The in situ process, like any other major operation, is expected to disturb a portion of the surface of the lease parcel at any given time. As with many oil and gas technologies, one might expect a reduced surface impact over time as in situ evolves into second and third generation technology. The R,D&D program is designed to require a phased reclamation approach. First, there will be intermediate reclamation of disturbed areas when those areas are no longer needed in the ongoing operations. As the operation terminates, the disturbed area of the lease is to be fully reclaimed before the lease bonds are released.

The BLM recognizes that the complexity of the NEPA analysis will depend on the site selected, the type of project proposed, and the type of technology to be used. The BLM will use the NEPA process to analyze the impacts to the land surface, vegetation, soil, underground water, air, surface water and fisheries and identify mitigation strategies to minimize adverse impacts. Additionally, as shown in the June 9th Federal Register notice, prior to conducting operations on the leased land, a lessee must submit a plan of operations that will include a description of best management practices for interim environmental mitigation and reclamation.

9. *Question: Although industry is touting some new innovations, their approaches to oil shale production still involve a major mining operation. What specific techniques and precautions will DOI require to ensure protection of surface water and ground water from depletion and contamination, to protect topsoil stability, and to control air pollution from that mining?*

Answer: Prior to the award of any lease, the BLM will conduct a NEPA analysis to determine that this protection is possible at the site using the proposed technology. Under the R,D&D program, a lessee will be required to submit a bond sufficient to cover actual expenses associated with total reclamation and abandonment prior to the issuance of a lease. The amount of the bond will be estimated based on the technology to be used and projected disturbance associated with such technology. Also, a lessee must submit an annual plan of operation to be reviewed and approved by an appropriate BLM official, subject to reasonable modifications to assure protection of the environment. Furthermore, a lessee will be required to provide an interim reclamation plan under which the lessee will be required to continuously reclaim disturbed portions of the lease as soon as such areas are no longer needed for operation.

Mr. GIBBONS. Thank you very much, Secretary Calvert. Again, the Committee appreciates your presence and the testimony here today.

Before we turn to questioning and answering of the Committee and interaction with the panel, a couple of housekeeping requirements. What I would like to do is ask unanimous consent to submit for the record the opening statement of Mr. Grijalva, the Ranking Minority Member, which will be done without objection.

[The prepared statement of Mr. Grijalva follows:]

Statement of The Honorable Raúl M. Grijalva, Ranking Democrat, Subcommittee on Energy and Mineral Resources

Today's hearing again focuses on a potentially untapped, domestic energy resource—oil shale and oil sands.

As I noted last week, while industry experts say oil shale holds great potential with an estimated 2 to 4 trillion barrels of oil locked in the Green River formation out west, it has a history in the western United States that is shaky at best. Many bold promises have been made in the past about oil shale's potential and about the affordability of its production but few of them have been realized so far.

It is important that we get clear facts about oil shale's fuel potential and about new methods for its production and that we are honest about analyzing and discussing those facts. We often hear, for example, that the United States currently consumes almost 20 million barrels of oil a day. Saudi Arabia now produces roughly 11 million barrels a day. If, as Chairman Gibbons suggested last week, this country could produce 60 percent of its oil needs from oil shale and tar sands, that would essentially mean equaling the current Saudi production figures, with much of it coming from Western Colorado.

However, as the Colorado newspaper, the Grand Junction's Daily Sentinel, editorialized on June 26, "No one who values the West's open spaces, wildlife and natural landscapes—in short, most Coloradans—would want to see a major swath of northwestern Colorado turned into a vast industrial zone that would make the likes of Gary, Indiana, look like a garden spot. To build the sort of oil-shale industry [Chairman] Gibbons envisions, the Rocky Mountain West as we know it today would have to be torched along with the shale itself."

So, we need to be careful about claims and projections and keep them in perspective.

Research phases need to examine not only ways to improve the technical aspects of oil shale production, but also the environmental consequences that could come from commercial operations. We need to know what damage an expanded industry could do to the water, air, scenic beauty, and recreation opportunities of the West and put in place the technical refinements and restrictions that reduce that damage.

Finally, as I stressed last week, with oil trading at $50 to $60 a barrel, and as evidenced by Shell's success in developing oil shale, Congress should not underwrite domestic oil shale development. The BLM proposal to lease tracts of public land for research and development is unobjectionable. But, American taxpayers do not need to subsidize oil shale development.

Mr. GIBBONS. And we also want to ask unanimous consent to submit for the record two publications from the Department of Energy: Volume One, dated March 2004, and Volume Two, dated March 2004; titled "Assessment of Strategic Issues," for Volume One, and Volume Two is "Oil Shale Resources Technology and Economics," for the record. That will be done, without objection, as well.

[NOTE: The information submitted for the record has been retained in the Committee's official files.]

Mr. GIBBONS. Let me begin, perhaps, with Dr. Barna over there. The issue of the Department of Defense and its role in assisting with or encouraging the development of oil shale products is primarily restricted not to technology, but to assessment of the product that is produced from whatever technology or whatever source of that.

Will there be interaction between DOD and our research and development and demonstration programs that the Department of Interior is proposing, as we go through the next ten years, to find the best or most suitable, not just product, but process by which we get product to the commercial? Will there be coordination?

Dr. BARNA. Absolutely. We intend to work with the Department of Interior, the Department of Energy. As you say, our primary role is to certify, to categorize, to help in the setting of specifications.

But this has to be done as a group process. It's just not going to be done in isolation; because our overall goal is to provide the catalyst for them to then develop an industry.

Mr. GIBBONS. Describe your process. What is it that you actually do when you get a product into your lab?

Dr. BARNA. Well, what we do is we actually run it on jet engines; we run it on diesel engines. We carefully monitor the energy inputs and outputs, and the particulate matter—NOXs and LXs, and when appropriate, SOXs. And we grade it.

And then we look at ways that we can change or improve specifications. One good example is—this is a recent experience with Fischer Tropsch fields. We may be able to change the specifications so that we get one fuel that does both jet and diesel. This helps industry, as well as helps us, because now we have one less fuel on the battlefield that we have to manage.

Mr. GIBBONS. Sure.

Dr. BARNA. So it is in the area of specifications, as well. So that is, I think, the area where we will have the best impact.

Mr. GIBBONS. Hopefully, we have provided a sample of what was provided to us from Oil-Tech, of products that come from oil shale, and the production of fuels. I presume that each of these products that you see up there, except for the waste rock after the oil has been removed, is a product that comes to you for that sort of testing.

Dr. BARNA. We would get the finished—we are interested in the finished fuel products. So we would be interested in the JP-8-like product or the——

Mr. GIBBONS. Diesel.

Dr. BARNA. Or the diesel product, exactly. And so sometimes we forget that there is a difference between what comes out of the ground and the finished product that goes into the machine. And our interest there is in that machine.

But we are very interested that they are all fit for use. So the jet fuel is jet fuel to the user. He doesn't really care if it comes from shale, biomass, oil, whatever; it's fit for his use. So that is where we would get very heavily involved.

Mr. GIBBONS. Secretary Maddox, has the Department of Energy performed an analysis of whether production of oil shale is economic?

Mr. MADDOX. That is part of the construction economics. We have looked at the numbers. And I think one of the things we have looked at is understanding the difference between profit versus competing investment alternatives. Right now, in this price range, yes, I would say oil shale is economic.

Mr. GIBBONS. Well, my question was, you are giving me your opinion.

Mr. MADDOX. Yes.

Mr. GIBBONS. Has the Department officially analyzed it and reported on the economics of it?

Mr. MADDOX. We have analyzed it. I don't know whether we have published those analyses. We will be happy to supply them to the Committee. But we have looked at the comparative costs of oil shale with other products in the market.

Mr. GIBBONS. And I assume this analysis would be with current technology?

Mr. MADDOX. Yes.

Mr. GIBBONS. Secretary Calvert, what are the three most important things that your Department and the Federal Government can do to assist in expediting the development of oil shale, or oil sands, or unconventional oil sources in this country?

Mr. CALVERT. I can speak on behalf of the Department of Interior. And as far as the rest of the Government goes, I'm not sure that I am qualified to say what DOD or DOE can best be doing to help.

But for the Department of the Interior, I feel, as the land managers here, it is our duty and responsibility to provide adequate NEPA coverage for development; to ensure that our land use plans under FLPMA are properly amended or supplemented; and then to process permits in a timely way and ensure that there is monitoring that goes along with it, so that we don't get snagged in legal battles.

Mr. GIBBONS. My time has expired. We will turn to Mr. Pearce for questioning. Mr. Pearce?

Mr. PEARCE. Thank you, Mr. Chairman. Mr. Maddox, we had a witness last week who said he could withdraw oil from shale for $18 to $24 a barrel. Do you believe that is possible?

Mr. MADDOX. That is probably an optimistic number. I would probably guess a little bit higher. Probably, at the $20 range would probably be fair, out of the ground.

Mr. PEARCE. And at the $20 range, why are we not doing it? Oil is at a $60 range.

Mr. MADDOX. Well, the fundamental economics are that you can get a lot of other oil out of the ground cheaper. And if you look at most corporate planning numbers, they look at a market price of $18 to $20 as kind of what most people are using for a planning number.

Most investment decisions are based on an historical average price, which I think now is just moving to $20 for a lot of companies. And so while people say, "OK, we can get it out of the ground for 20," that means a market price closer to 25, high 20s. And that does not work on an internal planning number for most corporations when they decide where to expend the money.

Mr. PEARCE. Do you think we don't have any entrepreneurs out there willing to risk? Right now, the margin is 40 bucks. You risk 20, and you make 60. From a business perspective, you don't find those kinds of rates of return. Why don't we have any takers?

Mr. MADDOX. Well, to compare the capital costs, you have a $70,000-per-barrel capital cost for oil shale, versus about a $33,000-per-barrel cost in oil sands, for instance. So there is a significant capital barrier. And so now you need an option in order to take a risk.

Mr. PEARCE. Does your estimate of cost—20, 25, or something in that range—include capital costs?

Mr. MADDOX. That's production cost.

Mr. PEARCE. Just production cost?

Mr. MADDOX. Yes.

Mr. PEARCE. So you mentioned in your written testimony that we should be able to squeeze out 2 to 3 million barrels a day, if we were able to access our resource and use it properly. How many acres would it take to get that kind of production?

Mr. MADDOX. I'm trying to remember that number. Basically, we are looking at 10,000 square miles.

Mr. PEARCE. Ten thousand square miles?

Mr. MADDOX. Yes.

Mr. PEARCE. To get that kind of production? And is that at 30 gallons per ton? How many tons do you get off of an acre?

Mr. MADDOX. At maximum concentration, we can get approximately 2-1/2 million barrels per acre.

Mr. PEARCE. So 2-1/2 million?

Mr. MADDOX. Barrels of oil.

Mr. PEARCE. Say that again?

Mr. MADDOX. Two and a half million barrels of oil per acre, per day.

Mr. PEARCE. Per what?

Mr. MADDOX. Per day.

Mr. PEARCE. No, I was asking about the number of tons of material per acre. In other words, you are saying you can get 2 to 3 million barrels a day out of shale oil. And I wonder how many acres it is going to take to get that done. How many acres?

Mr. MADDOX. Yes, one acre.

Mr. PEARCE. You said 10,000. I am trying to verify that with the number of——

Mr. MADDOX. Oh, for the——

Mr. PEARCE. Go ahead.

Mr. MADDOX. Well, we are looking to sustain this development long term.

Mr. PEARCE. That is what I am looking at, too.

Mr. MADDOX. Yes. Yes.

Mr. PEARCE. We are not talking about——

Mr. MADDOX. Yes, we are looking at approximately a 300-million-barrel—billion-barrel resource. So, I will have to, you know—let me clarify those numbers. I will be happy to submit them for the record.

Mr. PEARCE. I would like to find out the number. I would like two or three approaches. You say it is going to take 10,000 acres, and I would like some verification of that number. It is all I am trying to get.

Mr. MADDOX. Yes. I will be happy to supply those.

Mr. PEARCE. It will require us to consider the number of tons per acre of material that we are going to move. And to me, if we get 30 gallons per ton, that is not even yet a barrel per ton of material. And we will kind of come back to that, if you could help give us some documentation.

Mr. Chairman, I have other questions, but I will wait until the next round. I see that my time has about expired.

Mr. GIBBONS. Mr. Pearce, let me explain from an engineering standpoint that a ton of rock is literally pretty close to a cubic meter worth of rock. So one cubic meter, you could get about a ton of rock out of it. So that is probably this shale that is sitting right in front of us.

So a ton of material being that size, you would have to calculate the depth, thickness of the formation, the extent, the length, all of that. In an acre, if it is a 1,000-foot thickness, you can understand how many tons you are going to get off that real quickly.

Mr. PEARCE. I can work with the rock——

Mr. GIBBONS. That is why I gave it to you, so you could have something to do with that bright mind of yours besides sit here and ask questions.

Mr. Cannon?

Mr. CANNON. Thank you, Mr. Chairman. The other interesting thing about the size of a ton is that it equals about a barrel of oil, I understand. So it is interesting calculations.

But let me ask you this question, Dr. Barna. Are you familiar with the two technologies that have been presented? You have the Shell in-situ process, where they heat the shale and draw off the liquid; and then the, I don't know, we call it the "Savage process," essentially the old process but with some technical—do you happen to know how much water is required in either of those processes industrially? Are we talking about a significant amount of water?

Dr. BARNA. I do not, I am sorry to say. I am familiar with the process of how Shell Oil is going to use the in-situ and the above-ground retorting. But I am not a process expert. I am more at the consumer end of it.

Mr. CANNON. Thank you. Mr. Calvert or Mr. Maddox, do either of you have a sense about how much water either of these processes is going to take, on a per-barrel or other basis?

Mr. MADDOX. I am sure I have this here in my notes, if you give me a second to dig through this. When we are looking for oil shale, our production is probably 1 or 2 barrels of water for every barrel of oil we produce. About two-thirds of that water, though, is dedicated to human resources, supporting people and infrastructure around it. That is compared to oil sand production, which is about 2 to 4 barrels of water per barrel produced.

Mr. CANNON. Does that analysis distinguish between the in-situ Shell process and the "Savage process"?

Mr. MADDOX. It is generally considered approximately the same.

Mr. CANNON. OK.

Mr. MADDOX. From a planning standpoint. Somewhat, it is geared to the offsite support mechanisms; not necessarily the process.

Mr. CANNON. Do you have some documentation that analyzes that, that utilization?

Mr. MADDOX. We will be happy to——

Mr. CANNON. If you have something, I would really very much appreciate that.

Mr. MADDOX.—yes, submit it, in some form, either a question for the record, it would be great, and we can just submit it through there.

Mr. CANNON. Thank you. That would be perfect. Thank you very much.

Dr. Barna, you were talking about coming up with a fuel, a single fuel that would meet two purposes. Can you just elaborate a little bit on what it would take for a diesel fuel to be equivalent to—

I think you were talking about jet fuel—for those two? Is that a technically hard thing to do?

Dr. BARNA. We think it is possible. We have put out a draft specification to industry, and they are taking a hard look at that. We have an excellent opportunity with the Fischer Tropsch type fuels, because when they are recombined over a catalyst you can almost do it boutiquely. You can add the number of carbons that you want and the amount of branching.

So this just gives us the opportunity to look at what is available and then, rather than using specifications or certifications that go back to quite some time and tend to be patchwork, to look at the possibility of issuing new specifications that could cover this.

Mr. CANNON. Would that be specifications for the engines or motors, or would that be specifications for the fuel itself?

Dr. BARNA. It would be for the fuel itself. Our goal is, we don't want an 18-year-old on the battlefield to have to make a decision on—you know, if it is fuel for his vehicle, or her vehicle, it is going to work, it is going to be fit for that purpose. But it may be the same fuel that they are putting into a ship or an aircraft as well as a tank.

Mr. CANNON. Well, you are familiar with the fractions that come off naturally in the two processes. Are those fractions in the ballpark of the kinds of fuels that you are thinking in terms of?

Dr. BARNA. Well, I did that more of an illustration, sir, of, you know, sort of looking forward to see if we can make this process even better. We really haven't got our hands on enough of the fuel right now to do the testing we need to do. So as soon as that starts coming off the line, we will do that. And just as in the case of coal, we will look at reducing the number of fuels that the Department of Defense has to use.

Mr. CANNON. How much fuel do you need coming out of this testing process, to get a sense of that?

Dr. BARNA. Well, we are getting very little right now. Just on the Fischer Tropsch side, to do all the evaluation that we need, we are talking somewhere in terms totally of about 20 million gallons.

Mr. CANNON. OK.

Dr. BARNA. And that is the bottom.

Mr. CANNON. Thank you, Mr. Chairman. I see my time is about up. I yield back.

Mr. GIBBONS. Thank you very much, Mr. Cannon.

Let me also ask Secretary Calvert, with regard to the research, development, and demonstration project acreage, the 160-acre limit that you have out there, who decides on which acreage, or chooses the acreage? I am sure that there is a variation in terms of quality of oil shale that is out there, to make a determination. Who makes the decision on which 160-acre parcel you get?

Mr. CALVERT. Well, that is correct, Mr. Chairman. There is a big difference in the quality of the oil shale from place to place. And what we have asked is for companies to come in and nominate the 160-acre parcels. We leave it to them to identify where the best prospects are and to come in and nominate them.

Mr. GIBBONS. Is there a process by which they can go out and evaluate these oil shale deposits, in terms of vertical thickness or

quality, without having to go through a long, torturous EIS process?

Mr. CALVERT. Well, let me just check this, because what I am assuming is that they will be relying on previous USGS assessments of what was out there. If you will give me just a moment, please.

[Pause.]

Mr. CALVERT. Yes. The assessment was done in the mid-'80s, and they will be relying on that, is our assumption, to identify the high-quality locations.

Mr. GIBBONS. Those were mostly surface examinations of the deposit; were they not?

Mr. CALVERT. They were done with core samples, maps, surface identification, yes.

Mr. GIBBONS. OK. Where are you with regard to your commercial leasing regulation of oil shale? Where is the process right now? What is the expectation in terms of time to finish producing a regulation which will allow for commercial leasing of oil shale?

Mr. CALVERT. Congressman, we haven't actually begun the rulemaking process for that. But the BLM is prepared, once we got this rule out three weeks ago, to start this process. We estimate 18 months to two years for commercial leasing regs. The Department has the authority, under the Mineral Leasing Act, to issue such regulations, and we intend to move forward with that.

Mr. GIBBONS. When do you intend to move forward with it?

Mr. CALVERT. I can't give you an exact date, but we would like to move forward with it as soon as possible.

Mr. GIBBONS. Mr. Maddox, let me ask, if you in the Department of Energy do your economic analysis of oil shale using current technologies, using current economic pricing index, and find that oil shale is an economic resource, will that change the definition of the resource to a proven reserve, once you have done your economic analysis?

Mr. MADDOX. The definition of "proven reserves" actually is a Securities and Exchange Commission term. And that would have to imply commercial development plans and expenditures are being done on the property, and does not move to that point until production has actually started or the work toward production is started.

So from an SEC standpoint, it would take someone actually doing work and committing resources to bring it into production. From our standpoint, that's a reserve that exists; it is there; it is available. And the only thing preventing its development is the decision by someone to develop that resource.

Mr. GIBBONS. So if some company—say, Shell Oil Company—decides that its process is economically recoverable and that it wants to engage in that, and you make an economic determination in your publications—or you make that economic determination somehow—you would then see that if Shell is doing it economically, then according to SEC—the Securities and Exchange Commission—terminology, that it would change——

Mr. MADDOX. Right.

Mr. GIBBONS.—the resource to a proven reserve oil base in this country?

Mr. MADDOX. Correct. And that is one of the reasons why there was a shift a year or two ago on the oil sands; that it was deemed

as being developed and an appropriate level of private-sector development. So it was moved from an unproved reserve; which is why such a huge jump in the reserves in Canada.

Mr. GIBBONS. You don't see any obstacles with regard to environmental mitigation for development of this, do you, at this time?

Mr. MADDOX. Everyone understands that environmental issues need to be addressed. And I have complete confidence that they can be addressed.

Mr. GIBBONS. Now, getting back to my previous question, if I may take just a minute beyond my time, because I think I want to fully develop this idea about proven reserves, isn't this exactly what happened in the Canadian oil sands?

Mr. MADDOX. Exactly. It was not recognized as proven reserves until about two years ago, when you kind of had critical mass of investment.

Mr. GIBBONS. And did you have any involvement as the DOE with regard to designating them as proven reserves once this process took place?

Mr. MADDOX. No, we did not.

Mr. GIBBONS. So it was simply an industry regulation.

Mr. MADDOX. Right.

Mr. GIBBONS. Or an industry determination.

Mr. MADDOX. Uh-huh.

Mr. GIBBONS. All right. Mr. Pearce?

Mr. PEARCE. Thank you, Mr. Chairman.

Secretary Calvert, how long has your task force been going on? When did it start?

Mr. CALVERT. I believe it was convened in 1993.

Mr. PEARCE. 1993?

Mr. CALVERT. Yes, sir.

Mr. PEARCE. In 1993, the price was about 18 bucks; and in 1999, it eased down to 6 bucks. Now it is up to 60 bucks——

Mr. CALVERT. I'm sorry, 2003.

Mr. PEARCE. Oh, 2003?

Mr. CALVERT. Yes, sir.

Mr. PEARCE. In 2003, what was the price of oil?

Mr. CALVERT. Somewhere in the 20s, as I recall.

Mr. PEARCE. Now we are somewhere in the 60s. Do you have a department in your agency that says, "You know, the price just went from 20 to 60; can we accelerate this process?" Do you have a department that does that?

Mr. CALVERT. Accelerate the task force?

Mr. PEARCE. Accelerate the concept that we are becoming every day more dependent on oil; that the price of oil has the potential to break the economy; and that you have a resource there that is possibly—maybe not, but possibly—a source of great production. And do you ever get a little more, "Pick up your feet just a little, troops; let's move a little bit more fast, because the price could be 100 as easily as it could be back to 20"? Do you do that kind of discussion?

Mr. CALVERT. Well, of course, we do that kind of discussion. I have no doubt in my mind that there is commercially developable oil shale that not only can be produced, but can be transported in an economical way.

Mr. PEARCE. Why do you not have a doubt about that? Because right now, it appears you are even unwilling to take on the NEPA process for the 4,900-acre tract, or whatever, on top of the 160. You prefer to stay on the 160s.

Mr. CALVERT. Well, the problem with that is that we don't have any proposals. We have several different technologies out there, and it is hard to do the NEPA without the proposals.

Mr. PEARCE. You don't have any proposals right now to lease?

Mr. CALVERT. No, sir.

Mr. PEARCE. Lease land? Dr. Barna, does the fact that you are investigating alternative sources for DOD—because I am sure you are worried about national security and the availability. And in your report you say you have 1.4 trillion barrels of oil available; and yet you see the BLM doesn't even have a request out there. Does that make you wonder in the middle of the night if you really have correctly evaluated how much oil is really available to us?

Dr. BARNA. Well, I think that it is available as a resource, sir.

Mr. PEARCE. No, no, but if it is an available resource, that means we could go out and tap it. And yet, you see the process started in 2003, and the price has gone from 20 to 60, and the process hasn't picked its pace up at all. It is going to continue wandering on through this bureaucratic maze. And you say it is available, and I am not sure it is.

Dr. BARNA. When I say it is available; potentially available. You know, as soon as we can get it out of the ground. We have the processes to do it. We have the resources, but——

Mr. PEARCE. No, you only have the resources when you have the resources.

Dr. BARNA. When we have them. Right.

Mr. PEARCE. I have a desire to put a lot of money in the bank; but until I get it there, the banker is not going to loan me a house on it.

Secretary Calvert, you feel certain that when you get through this 18 months to two years that the Chairman talked about, that you will start leasing, if the plans were available?

Mr. CALVERT. Well, what we have is, we have land-use plans. And we would like to be able to do environmental assessments to those land-use plans for these 160 acres. They are much easier to do. We don't have to do full-scale EIS's on something that we don't actually know at this point——

Mr. PEARCE. Now then, we go over to Mr. Maddox's discussion about the number of tons per acre.

Mr. CALVERT. Well, we don't know. It could be the retort technology, it could be in-situ——

Mr. PEARCE. Is a 160-acre block economically viable?

Mr. CALVERT. Well, the economic viability is a commercial quantity of the available area, so it is a——

Mr. PEARCE. No, no, no, the economic viability—if I am drilling an oil well, the economic viability is the cost of that oil well and the amount of oil I can get out of it. And I am asking, is a 160-acre tract, if that is what you are going to lease because the NEPAs are a little bit difficult on the larger tracts, is a 160-acre tract an economically viable number?

Mr. CALVERT. [No response.]

Mr. PEARCE. I think we probably should have an answer to that at some point. And I guess my last question would be on this. So we are going to go 18 months to two years, and we are going to get this process for leasing. Why would I believe that this shale oil is going to be any more available than natural gas, when the BLM refuses to give leases in areas that have been previously drilled?

Again, I am trying to address the question of Dr. Barna there of: Do we have enough fuel; do we have enough energy for our own DOD requirements, our own defense? And I see the BLM unwilling to give leases on natural gas. What makes me think that in a process that is far more invasive, that we are ever going to even lease one acre? Can you give me an answer to that?

Mr. CALVERT. I think that is a legitimate concern. I am not sure exactly which BLM leases you are talking about, but the NEPA—I hold no illusions. NEPA on oil shale will not be a simple process. Depending on the technology, it could be very invasive, and depending on the location and the process that you go through. I don't anticipate it is going to be painless.

This is why, in order to expedite at least getting people onto BLM land, we decided to use EAs, instead of going straight for a full lease and have to do EIS's; because then we would be in a two-year process before they could ever even go out and start designing their plans. And I share your concern. We intend to proceed as aggressively as possible.

Mr. PEARCE. My time has expired, but I want to get my staff to give you exactly leases where the BLM in the Rocky Mountains is not issuing APDs so that people can drill, in areas that have been previously drilled. It is not like it is pristine. I will get you that information.

In the meantime, Dr. Barna, you might look at powering those airplanes and tanks with something else.

Mr. GIBBONS. Mr. Pearce, let me try to clarify your question about the 160-acre and economic viability. The 160-acre is simply for a research and demonstration project. It is not necessarily a determination. That 160-acre would be a limited amount for a commercial operation. It is there to determine whether or not the process by which they are trying to develop under the RD&D principle is suitable. So you are right, 160 acres would not——

Mr. PEARCE. I think that, in effect, this is something that we have to be aware of downstream. If the agency has got some concerns right now about NEPA processes, why are we saying this stuff is available? It may not ever be touched. And we need to be honest with ourselves if we are in this Committee hearing.

Mr. GIBBONS. I was only answering the question about the economic side of it before that. And there is an opportunity for extending the 160 acres.

Did you say 140, Mr. Calvert?

Mr. CALVERT. Up to the statutory maximum, which is 5,120.

Mr. GIBBONS. Five thousand, one hundred and twenty acres. All right. Mr. Cannon?

Mr. CANNON. Thank you. First of all, let me just point out that I love the idea of a "Department of Acceleration." That actually makes a lot of sense.

Following up on this, with the RD&D lease starting at 160 acres, the cost of developing that, depending upon the depth and lots of other things, could be very great. I mean, the operation in eastern Utah, as I recall, was 200 or 300 million dollars, just to develop the mine site. And you can hardly do that unless you are pretty sure you are going to go way, way beyond 160 acres.

Mr. Calvert, does that 160 acres relate also to the Shell process, where they are looking at a section of land? And with the resources they are dealing with, they are looking at a billion barrels of oil out of one section, but it is a terrifically expensive process to do; and yet, there is a certain minimum. And 160 acres is probably, I would think, in that situation too little acreage to really get an economically viable test, especially when you have two or three years.

Is that 160 acres going to be limiting for them? Or are you going to do an EIS process to make that a larger test?

Mr. CALVERT. Well, if they were to exercise their right to expand up to the 5,120 acres, it is our anticipation that, unless there were a programmatic EIS in place to cover it, we would have to do site-specific EIS's on those 5,000-acre developments.

Whether or not they can show commercial quantities on 160 acres, the reg that we issued in June is a little vague, because it is new territory what commercial quantities are and what commercial viability is; and essentially, put the burden on the company to show to the authorized officer that they can produce.

It is an equation that we exercise in coal leasing, for example, about diligence on commercial coal operations. These are functions that the BLM can do, I am certain. It is just not something that they have done before.

Mr. CANNON. You know, as each of the western states was brought into the Union, each state passed, or the Federal Government passed an organic act for each state, which were almost—or for the western states, public land states—were uniform in the obligation to do several things: set aside school trust lands; there was an obligation to sell the public lands and give a percentage of the proceeds of those sales, typically 5 percent, to the various states, and that would move, of course, Federal lands into productivity, and frankly into taxpaying status.

As Mr. Pearce has pursued this concept of how long it would take to get this resource into production, does it make sense for the Federal Government to be thinking in terms of getting the heck out of the business of controlling public lands and turning it over to states?

In particular, Mr. Bishop is about to introduce a bill that would require the Federal Government—which has not sold these public lands, as they are mandated to do by law—to take 5 percent of the Federal lands and turn them over to the states, probably to the school trust lands organizations.

Does it make sense to let the states choose lands, especially in Utah, Colorado, Wyoming, these shale oil lands, so that we can move them into production faster than it appears that the Department is able to do?

Mr. CALVERT. Well, this is kind of a trick question.

Mr. CANNON. Oh, it's a very straightforward question. For the Federal Government, it may be tricky.

Mr. CALVERT. If a bill were to pass to convey 5 percent of the lands to the states, then it would make sense for the states to choose lands that were productive for oil shale, and for oil and gas, and coal and everything else. It depends on how the bill were written.

Mr. CANNON. But of course, this is tricky because you don't have a departmental position on this thing yet.

Mr. CALVERT. Right.

Mr. CANNON. But I was asking your opinion. Does it make sense for America to get these lands in a context that is a state-owned context, so they could be developed more quickly?

Mr. CALVERT. It makes sense for America to get these lands into a context where they can be developed, yes, sir. Whether the states or the Federal Government can do it faster, I am not sure.

Mr. CANNON. Maybe not all states can do it faster than the Federal Government, but I can assure you that some would.

Mr. CALVERT. The State of Utah probably can.

Mr. CANNON. And with that, Mr. Chairman, I am going to yield back. My time is almost gone, but that is a great point to turn my time back, so I will do that.

Mr. GIBBONS. Thank you, Mr. Cannon. And we have been joined now by Mrs. Drake. Thelma, do you have any questions that you want to ask at this time? The floor is yours.

Mrs. DRAKE. Thank you, Mr. Chairman. I would just like to thank all of you for being here. I truly apologize for being so late today. But I was in the first meeting that we had on this issue; found it very, very informative. I think what I came away with on that one the most is that our friends in Canada have found a way to do this, to do it efficiently, to cut through the permitting process. My concerns are about where we are in the U.S.

You have probably already answered all of those questions, but I think that this is a national security issue. I think that we need to be certain that we are energy independent. I think this plays a major part in it. And I look forward to working with you.

And if any of you have comments, that is fine. You don't need to comment, because I know you have already answered a lot of questions from a lot of other people, and I am walking in right at the last minute. Mr. Chairman, thank you for pursuing this issue.

Mr. GIBBONS. You are welcome. And Mrs. Drake does raise a very valuable question for our Committee. I would turn to Dr. Barna, and ask how important is it to DOD, for example, to have a secure and reliable source of oil outside of a foreign source of oil dependency that we are in today?

Dr. BARNA. Well, I think it is very important. If we are importing half of our oil—and it is going to go close to 70 percent here by 2025, I believe are the estimates—we could be relying on people that don't necessarily have the same interests that we do and could cause a cut. And we certainly don't want to get where there is another limited supply, where then there have to be determinations made on how you use that supply.

So it is very important to us. And having an indigenous, secure supply of energy I think is certainly in the interests of the Department of Defense.

Mr. GIBBONS. Well, when you talk about the military, how much oil, and its products of oil, on a daily or annual basis, does the Department of Defense consume?

Dr. BARNA. We use approximately 4 percent of the energy, the jet fuel and the diesel that are used in the United States. So we are really not the big dogs on the porch there. But we use enough that we can perhaps influence——

Mr. GIBBONS. What, in terms of gallons or barrels, is that a day?

Dr. BARNA. I believe that is—let me check. About 300 to 350 thousand barrels a day, right now.

Mr. GIBBONS. That sounds like a whole lot more impressive than just saying 4 percent; although many people out there, if they knew the total amount of our consumption, could calculate that. Very important for you to say 350,000 barrels a day.

Dr. BARNA. And just to clarify, three-quarters of that is jet fuel. So that is really where our impact is made in this JP-8.

Mr. GIBBONS. And do you have an estimate of how much of that 350,000-barrels-per-day consumption is produced from foreign sources?

Dr. BARNA. I don't. Let me see.

[Pause.]

Dr. BARNA. We buy oil worldwide. And since we import about half of it, I assume it to be about half. But I really don't have the hard numbers to back that up.

Mrs. DRAKE. Mr. Chairman?

Mr. GIBBONS. Mrs. Drake.

Mrs. DRAKE. Wouldn't he be doing what we are doing as a nation, which is about 60, 62 percent, would be foreign oil? I mean, he doesn't have his own source.

Dr. BARNA. Right, exactly. I would assume that since we do a worldwide supply, that we are going to be importing—or our domestic resources would be somewhere around 50 percent, and the other half would come from outside America.

Mr. GIBBONS. We do have a strategic defense oil reserve; do we not?

Dr. BARNA. Yes, we do. That is under the Department of Energy, by the way.

Mr. GIBBONS. And today, are we filling that, or drawing oil out of it?

Mr. MADDOX. We are filling it at this point, I think.

Mr. GIBBONS. With $60-a-barrel oil?

Mr. MADDOX. That is actually royalty-in-kind oil, so it is oil coming in from the Gulf that is part of our lease payments.

Mr. GIBBONS. OK. Let me ask Mr. Maddox, in some of your publications from the Department of Energy, and indeed in some of your comments here, you talk about the greenhouse gas emission from the production of oil shale. Is not there a greenhouse gas emission from the production of oil from standard oil fields?

Mr. MADDOX. Yes, there is.

Mr. GIBBONS. So in essence, what we are saying is that regardless of how we get oil out of the ground, there will be a greenhouse gas emission?

Mr. MADDOX. That is correct.

Mr. GIBBONS. So it really isn't something that ought to prevent us from stopping production of oil shale because, as you say, there is a similar or like emission of greenhouse gases from production of an oil well in Texas or any place, Oklahoma, or the Gulf of Mexico?

Mr. MADDOX. Yes. Emissions are a fact of life in production. In fact, that is one of the issues Saudis are very interested in, in fact, is trying to learn how to capture some of that for EOR and other——

Mr. GIBBONS. Well, and also, if you look at the consumption of unconventional oils versus conventional oil—conventional oil being what we are talking about, Texas crude, Gulf of Mexico crude—is there a difference in the emissions that would come from oil produced from shale, versus conventional oil?

Mr. MADDOX. I just want to confirm that, actually. It is possible in the retort process, because of the high temperatures, you could have a higher level of emissions than you would under conventional oil.

Mr. GIBBONS. Doesn't a retort keep completely enclosed the environment in which the material is being heated?

Mr. MADDOX. My understanding is there are emissions; that it does not completely enclose; that there is a certain foaming and everything else, but there is a release point.

Mr. GIBBONS. Well, because one of the things they produce right here from this oil shale is propane. So if you had a release of propane, you have a real serious fire out there.

Mr. MADDOX. Yes.

Mr. GIBBONS. So they do control——

Mr. MADDOX. Capture, yes.

Mr. GIBBONS. They do control or capture the gases coming off of a retort.

Mr. MADDOX. As much as they can. But traditionally, CO2 is not captured. And that would be the issue. Now, there are uses. Again, you know, most of these are located near gas fields and other areas, and there is potential enhanced oil recovery use for that CO2; which is what we are doing in a number of demonstration projects right now.

Mr. GIBBONS. How about the in-situ recovery of oil, where it is a down-the-hole heating of the environment? What difference would there be from an in-situ versus a retort, with regard to greenhouse gas emission?

Mr. MADDOX. In-situ would actually have a lower level, because the heat and power that is generated is essentially created from an associated gas stream that powers the local generation. So essentially, you have something more similar to a low-emission natural gas generation facility. So you actually have a pretty low emission level coming in an in-situ process.

Mr. GIBBONS. So somehow, they recover the CO2, then, from the heating of the elements, or whatever power generation is required to heat the element that is down-hole?

Mr. MADDOX. The carbon is created above the hole in the generation of electricity, which is used to heat down-hole. So there is actually no CO2, or minimal CO2 produced from in-situ.

Mr. GIBBONS. Well, gentlemen, I commend each of you for your testimony here today, your presence, and the interest you have shown in what I believe is probably one of the most encouraging oil resources that we have seen or looked at in a long time to meet the energy needs of America.

As we know, the energy of our economy runs on oil. And the oil shales, oil sands of this country have all of the earmarkings of an enormously important product or process for assisting in the oil consumption of our economy, and one which I don't think we can either ignore; nor do I believe we can wait long to have it developed.

I think when the American public sees $100-per-barrel oil, they will be asking their government, "What did you do? What did you not do, knowing that it was coming, that could have expedited the production of oil, that could have mitigated or suppressed the per-barrel cost of oil in this country?"

We say it is ten years off from this point, down the road. I say it is ten years off because we lack the will power to do what is necessary to make sure that it is onboard, that it is being developed in a commercially expedited fashion.

And I think Mr. Pearce and Mr. Cannon are right. We need a government that looks down the road and says, "How can we make this happen quicker?" We have an obstacle mentality in government, for some reason. We look at this and say, "There are so many obstacles that we can't overcome them quickly."

I think we ought to be looking at how the industry faces these challenges. And the industry faces them from saying, "These are obstacles that we can overcome, and we can overcome them if we work together as a team."

I am pleased that the Department of Defense, the Department of Energy, and the Department of Interior, all have a related role in this. And every one of us, from the legislative branch to the administrative branch of government, have an obligation to see to it that we assist in the determination of this resource as to its viability in producing the energy sources to relieve the dependence of this country on foreign sources of energy.

That is an obligation that you have, as well as I do. And it is one which I take very seriously; and I hope you do, too. So I hope that the information we have gained from this allows for us to start thinking about: How do we expedite the process? How do we get this to the public? So that we can avoid the $100-per-barrel catastrophe that this is going to have on the U.S. economy.

With that, Mrs. Drake, do you have any additional questions?

Mrs. DRAKE. No, thank you, Mr. Chairman.

Mr. GIBBONS. Again, I want to thank our witnesses. You have been very good. We had planned to have us here for a little longer, but the good luck of the Irish got you out a little early.

We will submit written questions to each of our witnesses here today that we would like you to review and respond back to this Committee within ten days. The record will remain open for a period of about ten days, for members to submit written questions as well as opening statements.

With that, again, I hope you can see the interest that we have in developing alternative and unconventional sources of energy for

this country. And this appears to be one of the very promising resources that we have.

And let's hope for America that we do it right, and that we do it expeditiously; that we do it efficiently; that we do it environmentally soundly; and that we can answer the American public's demand for energy in this country in a timely and economic process.

With that, the hearing is adjourned.

[Whereupon, at 11:12 a.m., the Subcommittee was adjourned.]

[A statement submitted for the record by Dr. Robert Trent, Former Dean, School of Mineral Engineering, University of Alaska-Fairbanks, follows:]

Statement of Dr. Robert Trent, Former Dean, School of Mineral Engineering, University of Alaska-Fairbanks

While $60.00 per barrel crude oil has generated panic-driven calls for an "alternative Energy industry," hydrocarbons have begun the transition from conventional to Non-conventional oil. The historic inclusion of oil sands in Alberta as proven reserves Of bitumen deposits assessed at 178 billion barrels is the transformative bench-mark Between conventional and non-conventional. Expectations of a million barrels oil Per day from Alberta's tar sands has launched exploratory extractive and technology Interest in other sources from China to Venezuela to Utah.

The estimated oil sand resources in the United States are in excess of 60 billion barrels of proven and estimated reserves. In the lower 48, the majority of these reserves occur in four states: Utah, Alabama, Texas and California. Utah contains the largest of these reserves with estimates by the U.S. Geological Survey of approximately 11.3 billion barrels. Utah contains in excess of 40% of the United States estimated reserves and approximately 60% of the measured reserves. Utah has identified 54 oil sand deposits of which 10 are considered as major.

Two of the largest Utah deposits near an infrastructure that will be required for a timely production of the sands are Sunnyside and Asphalt Ridge. There are other large deposits in Utah, however they are remote and will require major capital for roads, power and pipelines. Sunnyside is the largest single oil sand deposit in the United States and is located in the southern portion of the Unita Basin. The Sunnyside deposit was estimated by the United States Geological Survey to contain 728 million barrels of 10 to 12 API gravity oil. Asphalt Ridge is estimated by Covington and others to contain 250 million barrels of oil.

The oil sands of the Sunnyside deposit lie on the southern flank of the Unita Basin. Elevation of the deposit ranges from 8,500 to 10,000 feet. The oil sands are in the upper part of the Wasatch formation and the lower part of the Green River formation. The most significant of oil occur in the Wasatch portion of the deposit. The saturated beds range in thickness from a few inches to more than 350 feet. Regional dip of the formation is north and east at 6 to 8 degrees. Much of the Sunnyside deposit can be surface mined and therefore offers an excellent target for economic development. The deposit is approximately eight miles from the Denver and Rio Grand Western Railroad and about six miles north of the coal mining area of Sunnyside. The United States Geological Survey estimates the deposit contains 1,600 million cubic yards of sands of which over 50% is commercial. Commercial grade is considered to contain in excess of 9% bitumen. As noted above, the Geological Survey estimates the deposit to contain 728 million barrels which is described as 450 million yards of measured and indicated material and 350 million yards as inferred material.

Asphalt Ridge runs Northwest/Southeast for approximately 10 miles. The ridge is approximately 3 miles from the town of Vernal Utah and is cut by highway 40. The more erosion resistant portions of the formation form the ridge for which it is named. The ridge is made from the Mesaverde sandstones and shales. The formation dips 8 to12 degrees to the southwest. The major bitumen saturation is in the Tertiary and Cretaceous age beds.

The bitumen is 12 degree API gravity and extremely low in sulfur. Vernal is a town where mining and conventional oil production is a large part of the economy and therefore the infrastructure to support an oil sand facility is present. Although the Asphalt Ridge deposit is not as large as Sunnyside it has received the most attention and research due to its location and infrastructure. Over the years several

projects have tried to produce the oil and currently there is a new 1,500 barrel/day refinery on the north edge of Vernal that is mothballed because the operator was not able produce enough crude using their process.

Prior research includes various compounds that act a diluents. These include diesel, hydrogen, hot water, centrifuges and solvents. In almost all cases the processes required heat. With the current cost of natural gas the economics of many of these processes is questionable. There have been bench scale tests of new products that do not require heat. These bench scale tests need to be expanded to demonstrations and pilot phases to prove the economics are favorable.

We do not believe the processes and methods used to produce bitumen in Canada can be economical in Utah. They require large amounts of energy in the form of natural gas and water. However, U.S. tar sands (Utah) recovery could begin with less capital "intensive and more energy-efficient recovery systems appropriate to smaller reserve Sites. This could take place with an efficient modular reconfigurable designed recovery System approach which, with demonstrated economics, will introduce Utah tar sands As an unconventional source of oil (hydrocarbons) in diminishing American dependence On imported fuels.

○