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Subcommittee of Jurisdiction: Energy & Power

One-page Summary of Harry Vidas Testimony
Before the Subcommittee of Energy & Power of the
U.S. House of Representatives Committee on Energy and Commerce

Due to technology advancements, the U.S. natural gas and oil resource base now is seen as extremely robust and diverse. Lower-48 production of shale gas, tight oil, and associated natural gas liquids has been an engine of economic growth in recent years. Our analysis of the remaining resource base indicates that this “unconventional” resource base is large and that this production activity is in the early stages of the resource development cycle with growing production and increased jobs expected for many years into the future.

In recent years, ICF has extensively evaluated shale gas and tight oil resources, both in terms of technical and economic recovery. This work has been sponsored by private companies, industry associations and government agencies. We have evaluated the geology, historic production and costs of all major U.S. and Canadian plays. This analysis shows that these resources are geographically widespread, and are economic to develop at moderate wellhead prices. The ICF analysis of these emerging natural gas and oil resources is done using a geographical information system (GIS) process that evaluates the resource at a highly granular level, accounting for variations in geologic factors, resource quality and economics within plays.

The assessed remaining recoverable U.S. natural gas resource base of 3,850 trillion cubic feet (Tcf) represents about 155 years of current annual consumption. The shale gas resource of 2,000 Tcf represents 52 percent of the total. This assessment should be viewed as conservative in that it assumes current technology and no major new plays. A very large portion of this resource base is economic at relatively low wellhead prices, and industry continues to make strides in reducing development costs.

U.S. oil production is increasing for the first time since 1984 and there is the potential for the U.S. to become a much larger oil producer in coming decades. The currently assessed U.S. oil resource base of 264 billion barrels represents 110 years of current annual production.

Crude oil and condensate production are surging as a result of tight oil plays such as the Bakken in North Dakota and the Eagle Ford in Texas. Tight oil production in the Permian Basin of West Texas is increasing and rig activity is very high. Future U.S. tight oil potential is excellent due to the wide range of potential producing plays and diverse geologic settings in numerous basins.

Relatively low cost and abundant gas and liquids resources are creating an upsurge in domestic manufacturing and chemicals industries. Chemical manufacturers in the U.S. have a large advantage over international firms whose energy and feedstock costs are higher. In addition, natural gas is increasingly displacing coal for power generation, resulting in reductions in greenhouse gas emissions. There is also a potential for natural gas to play a larger role as a transportation fuel.

The shale gas revolution has created a large demand for new and expanded mid-stream infrastructure, including gathering systems and processing plants. Liquids production from tight oil is driving the need to expand long-distance crude oil pipelines and will allow the expanded and more economic utilization of U.S. refineries.

U.S. Oil and Gas Resources

Harry Vidas
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February 5, 2013

Introduction

Chairman Whitfield, Ranking Member Rush, and members of the Subcommittee, I appreciate the opportunity to discuss my work in estimating the U.S. endowment of oil and natural gas resources.

Due to technology advancements, the U.S. natural gas and oil resource base now is seen as extremely robust and diverse. Lower-48 production of shale gas, tight oil, and associated natural gas liquids has been an engine of economic growth in recent years. Our analysis of the remaining resource base indicates that this "unconventional" resource base is large and that this production activity is in the early stages of the resource development cycle with growing production and increased jobs expected for many years into the future.

In recent years, ICF has extensively evaluated shale gas and tight oil resources, both in terms of technical and economic recovery. This work has been sponsored by private companies, industry associations and government agencies. We have evaluated the geology, historic production and costs of all major U.S. and Canadian plays. This analysis shows that these resources are geographically widespread, and are economic to develop at moderate wellhead prices. The ICF analysis of these emerging natural gas and oil resources is done using a geographical information system (GIS) process that evaluates the resource at a highly granular level, accounting for variations in geologic factors, resource quality and economics within plays.

This ICF analysis reflects recent upstream technology advances including those in the following areas:

- Horizontal drilling and steering
- Multi-stage hydraulic fracturing
- Fracturing fluids and techniques
- Seismic and other geophysical analyses of drilling locations
- Reductions in environmental impacts (multi-well pads, water conservation and recycling, reformulation of additives, reduced emission completions (RECs), etc.)

These upstream technology advances have enlarged the U.S. economic resource base by expanding areas where drilling can take place, increasing recovery factors and reducing capital and operating costs per unit of production.

ICF's estimate for the remaining technically recoverable U.S. natural gas resource base is 3,850 trillion cubic feet (Tcf), representing about 155 years of current annual consumption. Our total assessed remaining recoverable natural gas resource base for the U.S. plus Canada is 4,990 trillion cubic feet (Tcf), representing about 180 years of current consumption in the two counties. The North American shale gas resource of 2,600 Tcf makes up 52 percent of the total, with the U.S. assessed shale resources being almost 2,000 Tcf and Canada's portion being 600 Tcf. This assessment should be viewed as conservative in that it assumes current technology and no major new plays. A very large portion of this resource base is economic at relatively low wellhead prices, and industry continues to make strides in lowering development costs.

U.S. oil production is increasing for the first time since 1984 and there is the potential for the U.S. to become a much larger oil producer in coming decades. The currently assessed U.S. oil technically recoverable resource base of 264 billion barrels represents 110 years of current annual production and is roughly equivalent to the proved reserves of Saudi Arabia.

Crude oil and lease condensate production are surging as a result of tight oil[1] plays such as the Bakken in North Dakota and portions of the Eagle Ford in Texas. Tight oil production in the Permian Basin of West Texas is increasing and rig activity is very high. Future U.S. tight oil potential is excellent due to the wide range of potential producing plays and diverse geologic settings in numerous basins. Canadian tight oil production is also increasing rapidly across a wide area. The success of tight oil across such a wide spectrum of geologic settings indicates at a general level that most, if not all, historic oil producing areas will eventually see horizontal drilling. In most onshore areas, tight oil will likely ultimately dominate activity and production.

So called "wet gas" production is surging in shale gas plays such as the Eagle Ford in South Texas and the Marcellus in Pennsylvania. This wet gas exists in a transition zone between crude oil and dry gas. Wet gas contains natural gas liquids such as ethane, propane and butane that are key feedstocks in the petrochemical industry.

Relatively low cost and abundant gas and natural gas liquids resources are creating an upsurge in domestic manufacturing and chemicals industries. Chemical manufacturers in the U.S. have a large advantage over international firms whose energy and feedstock costs are higher. In addition, natural gas is increasingly displacing coal for power generation, resulting in a large reduction in greenhouse gas emissions. There is also a potential for natural gas to play a much larger role in the transportation sector as a vehicle fuel.

The shale gas revolution has created a large demand for new and expanded mid-stream infrastructure, including gathering systems and processing plants. Liquids production from tight

[1] Tight oil is defined as light-to-medium weight crude oil contained in petroleum-bearing formations of relatively low porosity and permeability such as shales and low permeability carbonates and sandstones. Extraction of the oil usually takes place through hydraulically fractured horizontal wells using natural reservoir drive mechanisms, that is, without the application of external heat or energy to change the characteristics of the oil or to "push" the oil out.

oil is driving the need to expand long-distance crude oil pipelines and will allow the expanded and more economic utilization of U.S. refineries.

There remains the potential for major new plays to emerge in both existing and frontier areas. For example, the Monterey tight oil play in Southern California has the potential to grow into a major supply in that region, with implications for infrastructure, refining, and economic activity.

Internationally, many countries are actively attempting to replicate the North American success with shale gas. ICF estimates that world shale gas technically recoverable resources are in the range of 12,000 Tcf. However, after several years of effort, it has become apparent that this effort will take longer than previously thought. Reasons cited in various countries include lack of industry expertise, lack of infrastructure, regulatory hurdles, poor economic incentives and problematic geology or economic factors. Well costs are generally much higher than in the U.S. and resource access is sometimes an issue in densely populated areas within Europe, India and China.

Analytic Framework and Assessment Summary

Over several decades, ICF has evaluated and assessed North American oil and gas resources. The assessments combine elements of the assessments by the U.S. Geological Survey, [2] the Bureau of Ocean Energy Management,[3] industry assessments such as that of the National Petroleum Council,[4] and in-house research.

In recent years, ICF has done extensive work to evaluate shale gas, tight gas, and coalbed methane in the U.S. and Canada using engineering and geology-based geographic information

[2] U.S. Geological Survey National Oil and Gas Assessment website http://energy.usgs.gov/OilGas/AssessmentsData/NationalOilGasAssessment.aspx

[3] BOEMRE 2006 OCS resource assessment http://www.boemre.gov/revaldiv/RedNatAssessment.htm

[4] National Petroleum Council, 2003, "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy," Washington, D.C.

system (GIS) approaches. This has resulted in one of the most comprehensive and detailed assessments of North American unconventional gas and oil resources available. It includes the analysis of all major unconventional gas plays and the most active tight oil plays.

The following resource categories have been evaluated:

> **Proven reserves** – the quantities of oil and gas that are expected to be recoverable from the developed portions of known reservoirs under existing economic and operating conditions and with existing technology. (Volumes shown are as of year-end 2010, and include conventional, tight gas, coalbed methane (CBM), and shale gas proven reserves).
>
> **Reserve appreciation** – the quantities of oil and gas that that are expected to be proven in the future through additional drilling in existing (producing) fields. Does not include growth in CBM or shale gas.
>
> **Enhanced oil recovery (EOR) –** recoverable oil volumes related to tertiary oil recovery operations, primarily CO_2 EOR**.**
>
> **New fields –** future new conventional field discoveries. Conventional fields are those with higher permeability reservoirs, typically with distinct oil, gas, and water contacts.
>
> **Shale gas and tight oil** – recoverable volumes of gas, condensate, and crude oil from future development of shale plays. Shale plays are defined as those in which the source and reservoir are the same (self-sourced). Tight oil plays are those shale plays that are dominated by oil and associated gas, such as the Bakken in North Dakota.
>
> **Tight gas –** recoverable volumes of gas and condensate from future development of very low permeability sandstones.
>
> **Coalbed methane** – recoverable volumes of gas from future development of coal seams.

Exhibit 1 summarizes the current ICF gas and crude oil assessments of the U.S. and Canada. Resources shown are “technically recoverable resources.” This is defined as the volume of oil or gas that could technically be recovered through vertical or horizontal wells under existing technology and stated well spacing assumptions without regard to price.

The assessment of remaining technically recoverable gas resources in the Lower-48, including proven reserves, is 3,545 Tcf and Alaska is assessed at 303 Tcf. The estimate for Canada is 1,142 Tcf. Shale gas in the Lower-48 is assessed at 1,964 Tcf and Canadian shale gas is assessed at 601 Tcf. The combined 2,565 Tcf of shale gas represents about 52 percent of the assessed gas resource base. The total resource base of 4,990 Tcf represents approximately 180 years of production and consumption at the current rate of about 28 Tcf per year for the U.S. plus Canada.

The estimate for remaining crude and condensate resources in the Lower-48 is 214 billion barrels, of which 56 billion barrels is from gas-prone or oil-prone shale and tight oil plays. Alaska resources are assessed at 50 billion barrels and do not yet include estimates of tight oil. The combined U.S. resource of 264 billion barrels can be compared to current U.S. annual production of 2.4 billion barrels and proven reserves of 23 billion barrels. North American crude and condensate resources total 307 billion barrels, of which 45 billion barrels is tight oil. The ICF resource assessment method results in a single point estimate of resources, rather than a probability range. However, the assessment inherently includes risk factors that are applied for individual plays, based upon geologic factors and the maturity of the play. Thus, the results represent a risked mean assessment.

Exhibit 1: ICF North America Oil and Gas Resource Base Assessment

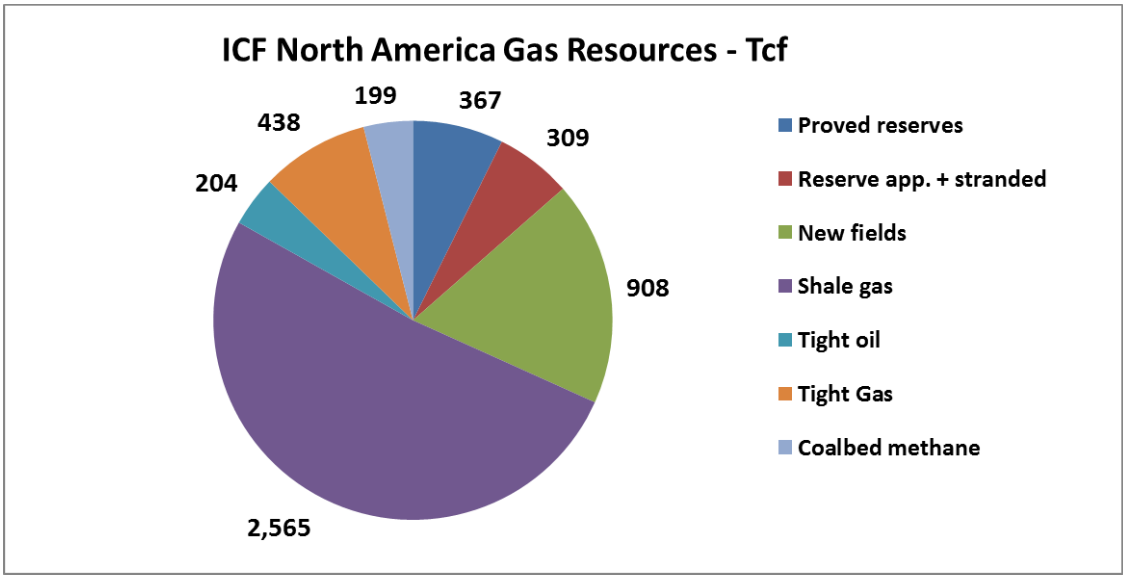
(excludes Canadian and U.S. oil sands)

Technically Recoverable Resources; Proved as of year end 2010
ICF Feb 2013

Lower-48	Dry Total Gas Tcf	Crude and Cond. Bn. Bbls
Proved reserves	297	21
Reserve appreciation	204	23
Stranded frontier	0	0
Enhanced oil recovery	0	42
New fields	488	68
Shale gas and condensate	1,964	31
Tight oil	88	25
Tight gas	438	4
Coalbed methane	66	0
Lower-48 Total	**3,545**	**214**

Alaska	Dry Total Gas Tcf	Crude and Cond. Bn. Bbls
Proved reserves	8.8	3.7
Reserve appreciation	22.0	3.5
Stranded frontier	14.0	0.0
Enhanced oil recovery	0	12.4
New fields	201	30.2
Shale gas and condensate	not assessed	not assessed
Tight oil	not assessed	not assessed
Tight gas	0	0
Coalbed methane	57	0
Alaska Total	**303**	**50**

Canada	Dry Total Gas Tcf	Crude and Cond. Bn. Bbls
Proved reserves	61	4.3
Reserve appreciation	29	3.0
Stranded frontier	40	0.0
Enhanced oil recovery	0	3.0
New fields	219	12.0
Shale gas and condensate	601	0.3
Tight oil	116	20.4
Tight gas (with conventional)	0	0.0
Coalbed methane	76	0.0
Canada Total	**1,142**	**43**
U.S. Totals	**3,848**	**264**
North America Totals	**4,990**	**307**



Sources: ICF, EIA (proved reserves)

Conventional Oil and Gas

The remaining conventional oil and gas resource consists of proven reserves, reserve appreciation in existing conventional fields, and undiscovered conventional fields. Conventional fields are higher permeability fields, typically with oil, gas and water contacts within a structural or stratigraphic trap.

Proven reserve estimates are published by the U.S. Energy Information Administration each year, at the state and district level. This series is based upon a large scale survey of operators. By definition, proven reserves are those quantities in existing fields that are recoverable under current economic conditions with existing technology. Production from proved reserves provides a base deliverability that can be projected into the future as part of future production. All of the volumes of proved reserves should be produced in future years, unless market and price conditions deteriorate, in which wells could be shut in earlier than anticipated.

Reserve appreciation in existing conventional fields represents a major component of future available resources. For many decades, operators have explored producing fields to add reserves through the discovery of new pools or through infill or extension activity. The advent of new technology that reduces costs or increases recovery per well can also result in the addition of new reserves. There are numerous methods used to estimate reserve appreciation, the most prevalent being “year of discovery” data series in which historical growth is evaluated, and factors are developed to be applied to recent discoveries. ICF also uses an analytic approach based upon trends in well recovery within a group of older fields.

For over 25 years, ICF has used a computerized modeling framework to evaluate remaining conventional undiscovered North American gas resources. This model contains a characterization of reserve appreciation, new conventional fields, and unconventional gas. Undiscovered fields are evaluated by drilling depth interval, water depth, and field size class.

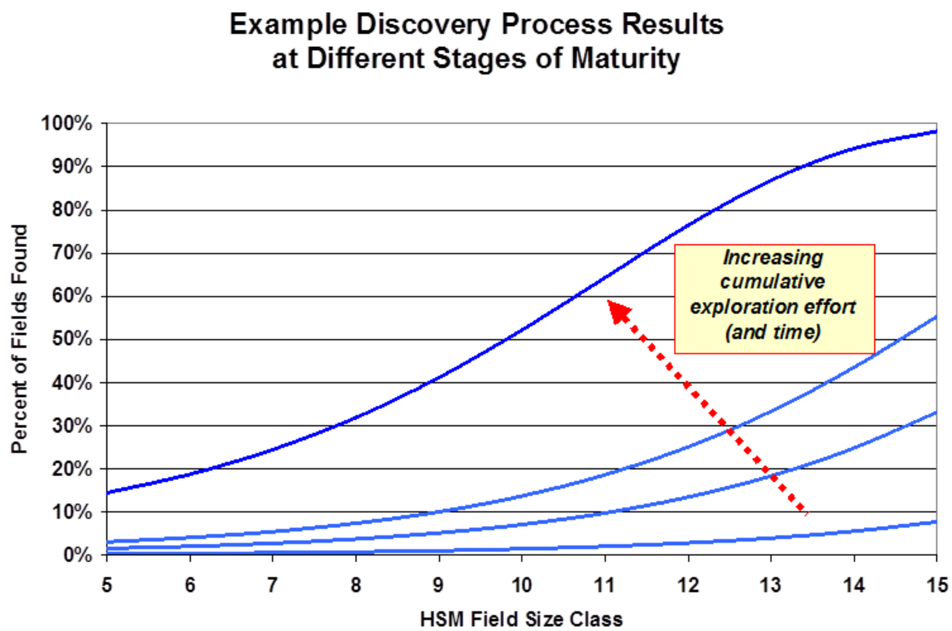
U.S. and Canada conventional resources are based largely on USGS and MMS (and other agencies in Canada) assessments made over the past 15 years or so. These assessments were extensively reviewed by industry representatives in the U.S. and Canada as part of the 2003 National Petroleum Council study, and recommended changes were implemented.[5] The model includes representations of oil, gas and natural gas liquids by play and depth interval. Costs are based upon actual drilling and completion costs and various scenarios for offshore fields as a function of water depth.

The model uses a discovery process algorithm to simulate the drilling of new field wildcats in a play. It estimates what is “discovered” by each increment of new field wildcat drilling. Some of the simulated discoveries are economic and many are not. The ones that are not economic are “banked” for future development. There is a procedure to add these undeveloped fields to the curve when the average cost of an exploration step reaches their development cost. **Exhibit 2**

[5] U.S. National Petroleum Council, 2003, “Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy,” http://www.npc.org/

illustrates the discovery process model. The upper blue curve illustrates the late stages of exploration in which all of the large fields in the play have been found.

Exhibit 2: ICF Discovery Process Model – Conventional Undiscovered Fields



Unconventional Oil and Gas

ICF has assessed future North America unconventional gas potential, represented by shale gas, tight sands, and coalbed methane. This work incorporates information on the geologic, engineering, and economic aspects of the resource. Evaluation with a geographic information system (GIS) allows a wide range of studies to better understand future trends in supply and infrastructure needs.

In recent years ICF has prepared various studies of U.S. and Canadian natural gas and oil supplies. For example, ICF produced reports on U.S. oil and gas resource endowment and future activity levels for the American Petroleum Institute (API)[6], the National Petroleum Council natural gas studies[7], the INGAA Foundation[8] and America's Natural Gas Alliance. We have also produced midstream infrastructure assessments for the NPC and the INGAA Foundation. ICF recently completed a study for the INGAA Foundation and other sponsors to project oil and gas resource development and infrastructure needs for the U.S. over the next 25 years.[9] The study included play level analysis of past and future drilling activity, estimated ultimate recovery (EUR) per well, and production for both gas and oil plays.

Shale Gas and Other Unconventional Gas Well Gas

ICF developed a GIS-based analysis system covering 32 major North American unconventional gas plays. Proprietary models were developed to work with GIS data on a 36-square-mile unit basis to estimate unrisked and risked gas-in-place, recoverable resources, EUR per well and wellhead and Henry Hub resource costs at a specified rate of return. The GIS analysis focused on gas and NGLs and addressed the issue of lease condensate and plant liquids, both in terms of recoverable resources and their impact on economics. Recently, ICF has developed assessments of several U.S. and Canadian tight oil plays, which also contain natural gas resources.

The ICF unconventional gas GIS model was originally developed in 2010 with the emergence of U.S. horizontal shale plays. The resource assessment component is based upon mapped parameters of depth, thickness, organic content, and thermal maturity, and assumptions about

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[6] ICF, "Strengthening Our Economy: The Untapped US Oil and Gas Resources," prepared for API, December 2008. http://www.api.org/aboutoilgas/upload/Access_Study_Final_Report_12_8_08.pdf

[7] National Petroleum Council, 2003, "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy." NPC. Washington, D.C. http://www.npc.org/. Also available at: http://www.fossil.energy.gov/programs/oilgas/publications/npc/03gasstudy/NG_Vol1_9-25.pdf

[8] INGAA Foundation, 2008, "Availability, Economics, and Production Potential of North American Unconventional Gas Supplies," prepared by ICF for Interstate Natural Gas Association of America, Washington, DC. http://www.ingaa.org/cms/31/7306/7628/7833.aspx

[9] INGAA Foundation, 2011, "North American Midstream Infrastructure Through 2035 – A Secure Energy Future, INGAA, Washington, DC http://www.ingaa.org/Foundation/Studies/14904/14889.aspx

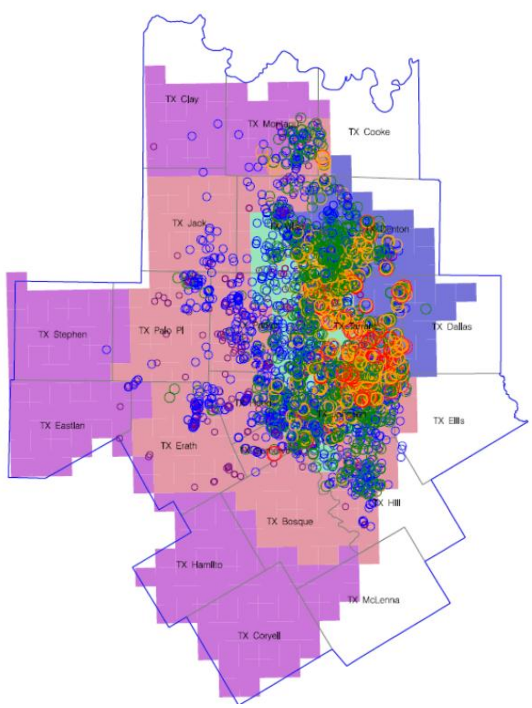
porosity, pressure gradient, and other information. The unit of analysis for gas -in-place and recoverable resources is a 6 by 6 mile or 36 square mile grid unit. Gas-in-place is determined for free gas, adsorbed gas and gas dissolved in liquids and well recovery is modeled using a reservoir simulator. Well recovery is estimated as a function of well spacing. **Exhibit 3** is a map of Lower-48 shale gas plays, most of which are included in the model.

Economic analysis is also performed on a 36-square-mile unit and is based upon discounted cash flow analysis of a typical well within that area. Model outputs include risked and unrisked gas-in-place, recoverable resources as a function of spacing, and supply versus cost curves.

One of the key aspects of the analysis is the calibration of the model with actual well recoveries in each play. **Exhibit 4** shows Fort Worth Basin Barnett shale play well recoveries. These data are derived from ICF analysis of a commercial well level production database. The actual well recoveries are compared with the model results in each 36 square mile model cell to calibrate the model. Thus, our results are not just theoretical, but are ground-truthed to actual well results.

Exhibit 3: North America Shale Gas Plays (EIA)

Exhibit 4: ICF Map of Fort Worth Barnett Shale Well Recoveries



Tight Oil

Tight oil production is black oil production from shale and other low permeability formations including sandstone, siltstone, and carbonates. The tight oil resource has emerged as a result of horizontal drilling and multi-stage fracturing technology. Tight oil production in both the U.S. and Canada is surging. Production in January of 2013 is approximately 1.4 million barrels per day (b/d) in the U.S., up from almost zero in 2007, and 250,000 b/d in Canada.

Tight oil includes the development of previously undrilled plays, such as the Bakken shale, and in other cases concentrates on the fringes of old oil fields, which is occurring in Canada.

Exhibit 5 lists the tight oil plays that have been assessed by ICF. The assessment of each play is based upon map areas or “cells” with averaged values of depth, thickness, maturity, and organics. The model takes this information, along with assumptions about porosity, pressure, oil gravity, and other factors to estimate original oil and gas-in-place, recovery per well, and risked recoverable resources of oil and gas. The results are compared to actual well recovery estimates. A discounted cash flow model is used to develop a cost of supply curve for each play. Well recoveries in the model are compared with actual drilling results where such data are available.

As presented previously, the ICF estimate for remaining crude and condensate resources in the Lower-48 is 214 billion barrels. The resource can be compared to current Lower-48 annual production of 1.8 billion barrels and proven reserves of 21 billion barrels and U.S. oil production of 2.4 billion barrels. North American crude and condensate resources total 307 billion barrels, of which 45 billion barrels is tight oil. Currently assessed tight oil resources alone represent about 20 years of current annual production.

Exhibit 5: Tight Oil Plays Assessed by ICF

Play	Unrisked Square Miles	Play	Unrisked Square Miles
US			
US Bakken Shale - Williston Basin	21,852	Monterey - San Joaquin Basin, CA	1,530
Niobrara Shale - Denver Basin	8,900	Kreyenhagen - San Joaquin Basin, CA	1,845
Niobrara Shale - Powder R. Basin	6,300	**Canada ***	
		Canada Bakken Shale - Williston Basin	1,944
Niobrara Shale - Green River Basin	2,088		
		Montney-Doig	2,800
Niobrara Shale - Piceance Basin	3,528		
		Duvernay - WCSB	31,896
Avalon Shale - W. Texas	7,900		
		Cardium - WCSB	11,011
Bone Springs Clastics - W. Texas	4,400		
		Viking - WCSB	8,715
Wolfberry Clastics - W. Texas	5,100		

* Additional preliminary studies of Shaunavon, Ameranth, Exshaw, Slave Point, and Beaverhill Lake fms.

Technology Assumptions

An important aspect of resource assessment is the underlying assumption about technology. The ICF resource assessment is based upon the assumption of existing technology. This is a conservative assumption, as has been demonstrated by the very rapid technology growth in shale gas and tight oil development in just five years. Technology improvements may result in higher well recoveries, lower costs, and less environmental impact.

Comparison with Other Assessments

The ICF gas resource assessment, especially for shale gas, is higher than other published assessments. The difference results from the inclusion of more plays and from our more inclusive and extensive geological and engineering approach to resource assessment.

Several groups in the U.S. and Canada publish oil and gas resource assessments. These include the following:

- The U.S. Energy Information Administration (Annual Energy Outlook). This assessment is revised each year and is primarily based upon USGS and BOEM assessments, with a recent EIA evaluation of shale gas. [10] The USGS assessment is an ongoing assessment being carried out basin by basin.
- The U.S. Potential Gas Committee. This is a group of U.S. gas supply experts from industry and academia that put out an assessment of the Lower-48 and Alaska every two years. [11]
- Canadian Society for Unconventional Gas (industry group) [12]
- MIT Energy Initiative. This is an academic group that published a study in 2011.[13]
- Advanced Resources International. ARI is a private firm that has done oil and gas assessment work for DOE and others. [14]
- INTEK shale assessment for EIA. This is a private firm that has developed a new shale assessment under contract to EIA [15]

A comparison of various recently published assessments is shown in **Exhibit 6**. Most of the difference is with the shale gas assessment. [16]

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[10] EIA assumptions of the 2011 Annual Energy Outlook http://www.eia.gov/forecasts/aeo/

[11] U.S. Potential Gas Agency, 2011, "Potential Supply of Natural Gas in the United States," Potential Gas Committee, Colorado School of Mines, Golden Colorado. http://www.potentialgas.org/

[12] Canadian Society for Unconventional Gas (CSUG), 2011, http://www.csug.ca/

[13] MIT Energy Initiative, 2011, "The Future of Natural Gas," http://web.mit.edu/mitei/research/studies/report-natural-gas.pdf

[14] Advanced Resources International, 2010, "U.S. Natural Gas Resources and Productive Capacity," prepared for Chenier Energy LNG export application, August 26, 2010. http://www.chenierenergypartners.com/lng_documents/application_exhibits.pdf (pages 234-349)

[15] INTEK, 2010, "Review of Emerging Resources – U.S. Shale Gas and Shale Oil Plays," included with EIA AEO documentation materials; http://www.eia.gov/analysis/studies/usshalegas/

[16] In some cases these may not be the most recent assessment.

Exhibit 6: Comparison of Lower-48 Natural Gas Assessments

ICF, January 14, 2013
TCF of technically recoverable gas; excludes proved reserves

Group	Shale Gas and Tight Oil	Tight Gas	Coalbed	Conventional	Unproved Total
ICF, 2013	2,052	438	66	707	3,263
EIA AEO, 2011	827	369	117	703	2,016
PGC, 2011	687	(with conv.)	102	858	1,647
MIT, 2011	631	173	115	951	1,870
ARI, 2010	660	471	85	831	2,047

Notes:
ICF shale gas includes tight oil associated gas.
PGC assessment does not break out tight and conventional.
MIT assessment of conventional gas shown here includes Alaska

There are several reasons why the ICF shale gas assessment is higher than other published assessments:

- More plays are included by ICF. ICF includes all major shale plays that have significant activity or industry interest.
- ICF includes the entire shale play, including the oil portion. Several plays such as the Eagle Ford have a large liquids area. The oil portion of the play may contain large volumes of associated gas.
- ICF employs a bottom-up engineering evaluation of gas-in-place, original oil-in-place (OOIP), and recoverable hydrocarbons. This analysis is based upon mapped geological parameters and well accepted reservoir simulation and modeling methods.
- ICF estimate incorporates infill drilling and the latest current technologies that increase the volume of reservoir contacted and recovery factors.
- ICF includes conventional gas in the areas of the outer continental shelf (OCS) that are currently off-limits, such as the Atlantic OCS. Some of this resource may be made available, but it is not a large part of our resource base.

- ICF evaluates all hydrocarbons at the same time (dry gas, NGLs, crude, and condensate). The inclusion of liquids is a critical aspect of prospect economics and has a large impact on the supply curve.
- The ICF resource is a "risked" resource. ICF employs an explicit risking algorithm based upon the proximity to nearby production and factors such as thermal maturity or thickness.

The ICF assessment is based upon extensive geologic, engineering, and economic analysis. ICF believes that other shale assessments are low because they are not as inclusive or comprehensive in their approach and may not include the most recent data. The ICF well recovery estimates and development and production forecasts are supported by actual production and EUR per well results where historical data are available.

Gas Resource Costs

ICF has developed supply cost curves for the U.S. and Canada. These curves represent the aggregation of discounted cash flow analyses at a highly granular level. Resources included in the curve are all of the resources discussed above – proven reserves, growth, new fields, and unconventional gas. The unconventional GIS plays are represented in the curves by thousands of individual DCF analyses.

Conventional and unconventional gas resources are determined using different approaches due to the nature of each resource. For example, conventional new fields require new field wildcat exploration while shale gas is almost all development drilling. Offshore undiscovered conventional resources require special analysis related to production facilities as a function of water depth.

The basic ICF resource costs are determined "at the wellhead" prior to gathering, processing, and transportation. However, cost estimates have been developed to allow costing at points farther downstream of the wellhead. In addition, costs can be adjusted to a “Henry Hub” basis for certain type of analysis that consider the remoteness of the resource.

Supply Costs of Conventional Oil and Gas

Conventional undiscovered fields are represented by a field size distribution. Such distributions are typically compiled at the “play” level. Typically, there are a few large fields and many small fields remaining in a play. In the model, these play level distributions are aggregated into 5,000 foot drilling depth intervals onshore and by water depth interval offshore. Fields are evaluated in terms of barrels of oil equivalent, but the hydrocarbon breakout of crude oil, associated gas, non-associated gas, and gas liquids is determined. All areas of the Lower-48, Canada, and Alaska are evaluated.

Costs involved in discovering and developing new conventional oil and gas fields include the cost of seismic exploration, new field wildcat drilling, delineation and development drilling, and the cost of offshore production facilities. The model includes algorithms to estimate the cost of exploration in terms of the number and size of discoveries that would be expected from an increment of new field wildcat drilling.

Supply Costs of Unconventional Oil and Gas

ICF has developed models to assess the technical and economic recovery from shale gas and other types of unconventional gas plays. These models were developed during a large-scale study of North America gas resources conducted for a group of gas producing companies, and have been subsequently refined and expanded. North American plays include all of the major shale gas plays that are currently active. Each play was gridded into 36 square mile units of analysis. For example, the Marcellus Shale play contains approximately 1,100 such units covering a surface area of almost 40,000 square miles.

The resource assessment is based upon volumetric methods combined with geologic factors such as organic richness and thermal maturity. An engineering based model is used to simulate the production from typical wells within an analytic cell. This model is calibrated using actual historical well recovery and production profiles.

The wellhead resource cost for each 36-square-mile cell is the total required wellhead price in dollars per MMBtu needed for capital expenditures, cost of capital, operating costs, royalties, severance taxes, and income taxes.

Wellhead economics are based upon discounted cash flow analysis for a typical well that is used to characterize each cell. Costs include drilling and completion, operating, geological and geophysical (G&G), and lease costs. Completion costs include hydraulic fracturing, and such costs are based upon cost per stage and number of stages. Per-foot drilling costs were based upon analysis of industry and published data. The API Joint Association of Drilling Costs and Petroleum Services Association of Canada (PSAC) are sources of drilling and completion cost data, and the EIA is a source for operating and equipment costs.[17,18,19] Lateral length, number of fracturing stages, and cost per fracturing stage assumptions were based upon investor slides and other sources.

In developing the aggregate North American supply curve, the play supply curves were adjusted to a Henry Hub, Louisiana basis by adding or subtracting an estimated differential to Henry Hub. This has the effect of adding costs to more remote plays and subtracting costs from plays closer to demand markets than Henry Hub.

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[17] American Petroleum Institute, various years, "Joint Association Survey of Drilling Costs," API, Washington, DC.

[18] Petroleum Services Assn. of Canada, 2009, "2009 Well Cost Study." http://www.psac.ca/

[19] U.S. Energy Information Administration, 2011, "Oil and Gas Lease Equipment and Operating Costs," http://www.eia.gov/petroleum/reports.cfm

The cost of supply curves developed for each play include the cost of supply for each development well spacing. Thus, there may be one curve for an initial 80-acre-per-well development, one for 40-acre-per-well. This approach was used because the amount of assessed recoverable and economic resource is a function of well spacing. In some plays, down-spacing may be economic at a relatively low wellhead price, while in other plays, economics may dictate that the play would likely not be developed on closer spacing. The factors that determine the economics of infill development are complex because of varying geology and engineering characteristics and the cost of drilling and operating the wells.

The analysis is based on current practices and costs and therefore does not include the potential for either upstream technology advances or drilling and completion cost reductions in the future. Throughout the history of the gas industry, technology improvements have resulted in increased recovery and improved economics. In oil and gas resource assessment and forecasting, assumptions are typically made that well recovery improvements and drilling cost reductions will continue in the future and will have the effect of reducing supply costs. Thus, the current study may be considered a conservative representation of the resource base.

Aggregate Cost of Supply Curves

North America supply cost curves on a "Henry Hub" price basis are presented in **Exhibits 7 and 8**. The costs in each basin have been adjusted to account for basis differential to Henry Hub, Louisiana. The supply curves were developed on an "oil-derived" basis. That is to say that the liquids prices are fixed in the model (crude oil at $95 per barrel) and the gas prices in the curve represent the revenue that is needed to cover those costs that were not covered by the liquids in the DCF analysis. The rate of return criterion is 10 percent, in real terms. Current technology is assumed.

For the Lower-48, 2,300 Tcf of gas resource is available at $10.00 per MMBtu or less.   For Canada there is 650 Tcf at at $10.00 per MMBtu or less. At $5.00 per MMBtu, over 1,200 Tcf is available in the Lower-48 and approximately 300 Tcf is available in Canada.

This analysis shows that a very large component of the technically recoverable resource is economic at relatively low wellhead prices. This assessment could well be conservative in that it assumes no improvement in drilling and completion technology and cost reduction, while in fact, large improvements in these areas are being made.

Exhibit 7: ICF U.S. Natural Gas Supply Curve – Henry Hub Basis

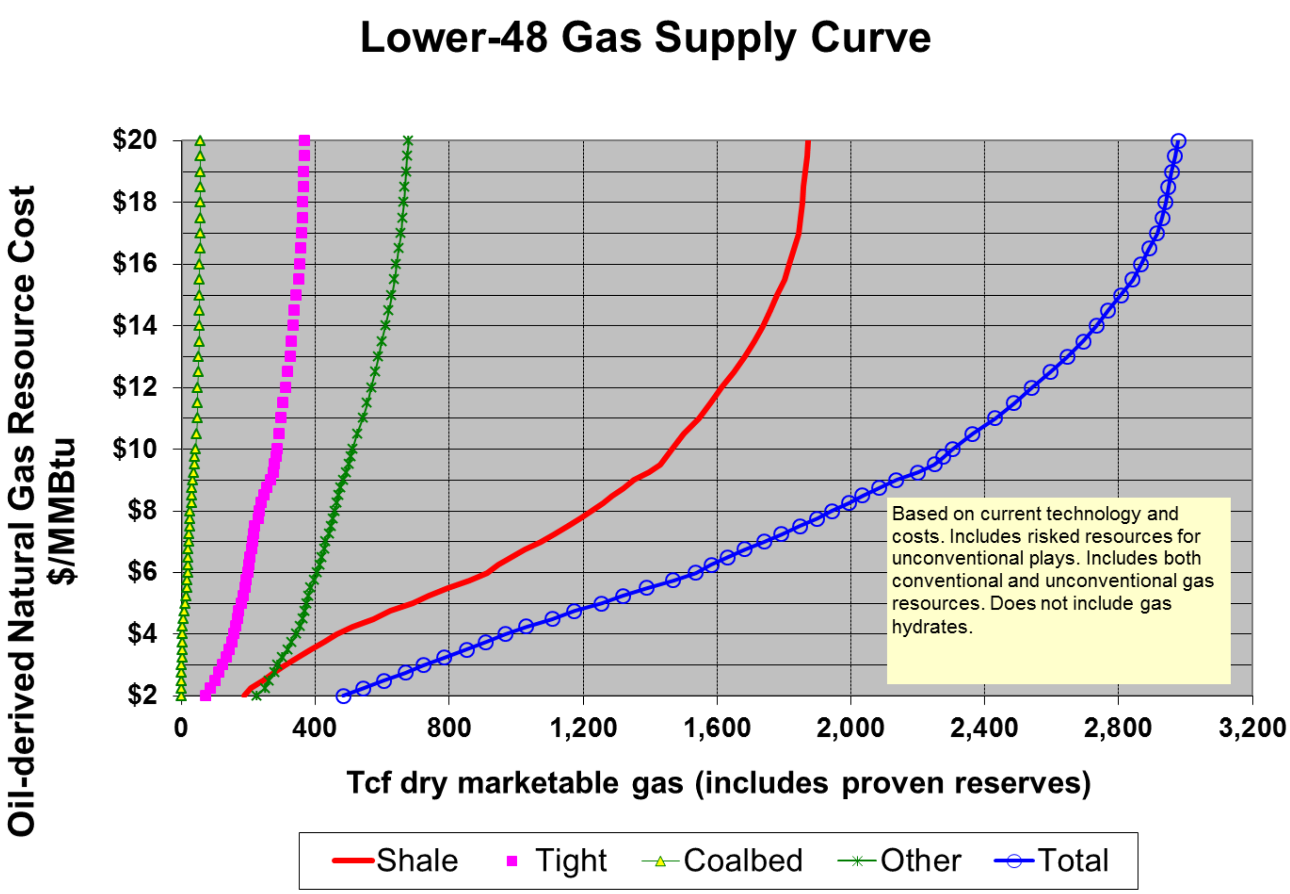
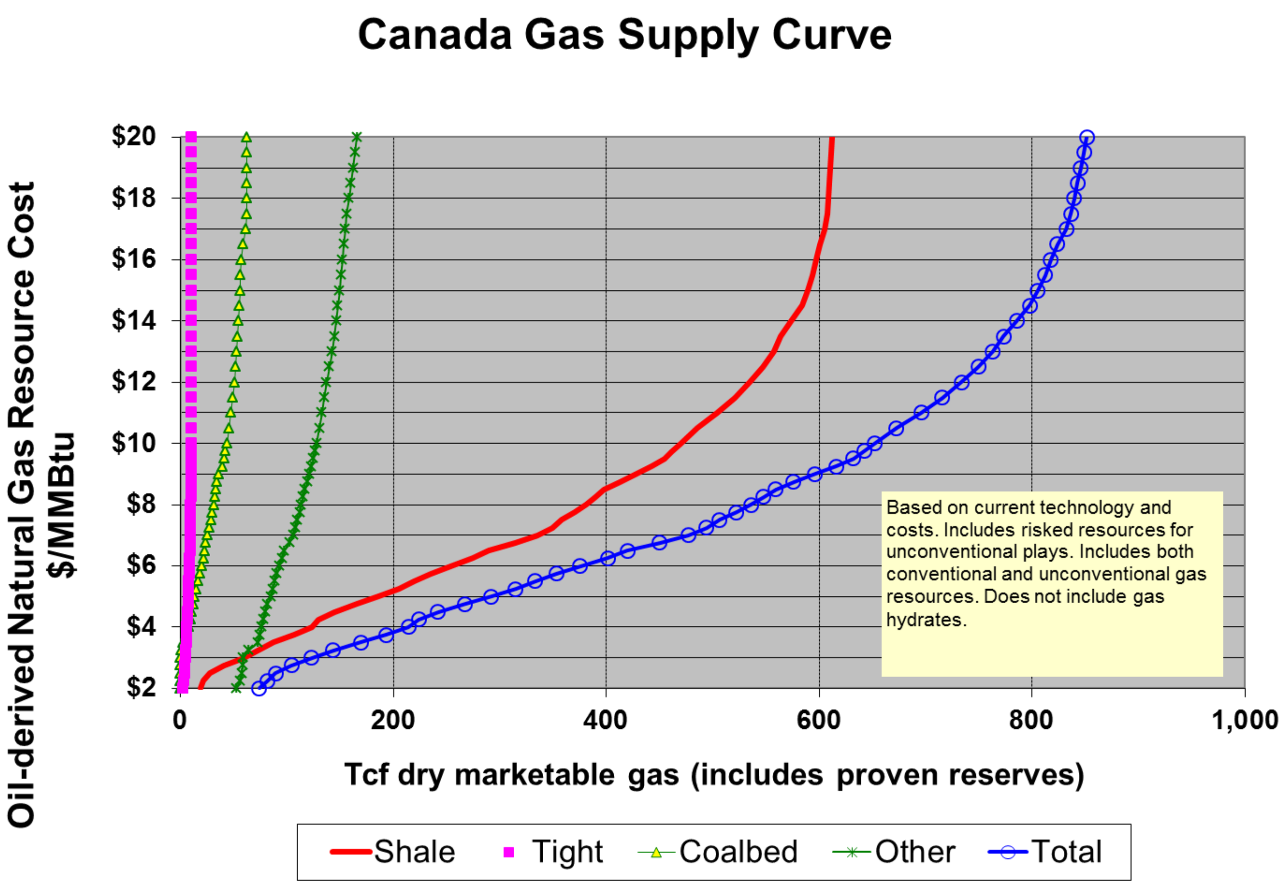


Exhibit 8: Canada Natural Gas Supply Curve – Henry Hub Basis



Source: ICF