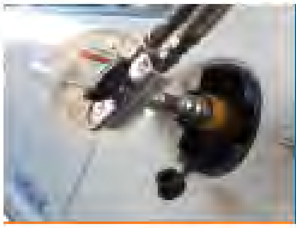


Investor day 2010

ENCANA CORPORATION
Investor Day: March 16 & 18, 2010

Legal Advisories:

Agenda:

Future Oriented Information

In the interest of providing Encana Corporation ("Encana" or the "Company") shareholders and potential investors with information regarding the Company, its subsidiaries, including management's assessment of the Company's future plans and operations, certain statements and graphs throughout these presentations contain "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 or "forward-looking information" within the meaning of applicable Canadian securities legislation. Forward-looking statements in these presentations include, but are not limited to, statements and tables with respect to: total and per resource play's estimates of reserves and economic contingent resources and the future economic opportunities that they may provide to Encana; the Company's goal to double the size of Encana over the next five years, including doubling its daily production; the expected development of low estimate economic contingent resources after development of proved reserves once the contingencies relating to the same are removed; estimated number of net drilling locations available; projected and additional capital to be invested in 2010 including in various resource plays; projections contained in the Company's guidance forecasts and the anticipated ability to meet the Company's guidance forecasts; anticipated producing life of reserves and resources; anticipated growth, production and success of resource and emerging plays and the expected characteristics of resource plays; estimates of recoverable quantities of reserves and resources of natural gas and liquids; expected returns at different price ranges; potential increases in demand for natural gas for use in transportation and power generation; targeted financial metrics for 2010; estimates for natural gas prices for 2010 and beyond; capital appreciation and dividend expectations; and projected share purchases under Encana's NCIB program.

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These assumptions, risks and uncertainties include, among other things: volatility of and assumptions regarding commodity prices; assumptions based upon the Company's current guidance; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in the Company's marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of natural gas and liquids from resource plays and other sources not currently classified as proved, probable or possible reserves or economic contingent resources; marketing margins; unexpected cost increases or technical difficulties in constructing or modifying processing facilities; risks associated with technology; land expiration risks; the Company's ability to replace and expand gas reserves; its ability to generate sufficient cash flow from operations to meet its current and future obligations; its ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company's ability to secure adequate product transportation; changes in royalty, tax, environmental, greenhouse gas, carbon, accounting and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which the Company operates; terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the Company; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by Encana. Although Encana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Forward-looking statements with respect to anticipated production, reserves and Company size growth, including over the next five years, is based upon numerous facts and assumptions which are discussed in further detail in these presentations, including Encana's current net

Back to Agenda

drilling location inventory, natural gas price expectations over the next few years, production expectations made in light of advancements in horizontal drilling, multi-stage fracture stimulation and multi-well pad drilling, the current and expected productive characteristics of various existing and emerging resource plays, Encana's estimates of proved, probable and possible reserves and economic contingent resources, expectations for rates of return which may be available at various prices for natural gas and current and expected cost trends. In addition, assumptions relating to such forward-looking statements generally include Encana's current expectations and projections made in light of, and generally consistent with, its historical experience and its perception of historical trends, including the conversion of resources into proved reserves and production as well as expectations regarding rates of advancement and innovation, are generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in these presentations.

Forward-looking information respecting anticipated 2010 cash flow for Encana (post transaction) is based upon achieving average production of oil and gas for 2010 of between 3.2 and 3.3 Bcfe/d, commodity prices for natural gas of NYMEX $5.75/Mcf, crude oil (WTI) $75, U.S./Canadian dollar foreign exchange rate at $0.94 and an average number of outstanding shares for Encana of approximately 750 million. Furthermore, the forward-looking statements contained in these presentations are made as of the date of these presentations, and, except as required by law, Encana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in these presentations are expressly qualified by this cautionary statement.

Advisory Regarding Reserves Data & Other Oil & Gas Information Disclosure Protocols

Encana's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to Encana by Canadian securities regulatory authorities which permits it to provide certain of such disclosure in accordance with the relevant legal requirements of the U.S. Securities and Exchange Commission (the "SEC"). Some of the information provided by Encana may differ from the corresponding information prepared in accordance with Canadian disclosure standards under National Instrument 51-101 (NI 51-101). Information about the differences between the U.S. requirements and the NI 51- 101 requirements is set forth under the heading "Note Regarding Reserves Data and Other Oil and Gas Information" in Encana's Annual Information Form dated February 18, 2010.
The reserves numbers contained in these presentations represent estimates of Encana's reserves prepared using SEC definitions and standards, applying forecast prices. Encana has used Henry Hub forecast prices of $5.50 per MMbtu for 2010 and $6.50 per MMbtu for 2011 and beyond.
The estimates of economic contingent resources contained in these presentations are based on definitions contained in the Canadian Oil and Gas Evaluation Handbook. Contingent resources do not constitute, and should not be confused with, reserves. Contingent resources are defined as those quantities of petroleum estimated, on a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Economic contingent resources are those contingent resources that are currently economically recoverable. In examining economic viability, the same fiscal conditions have been applied as in the estimation of reserves. There is a range of uncertainty of estimated recoverable volumes. A low estimate is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate, which under probabilistic methodology reflects a 90% confidence level. A best estimate is considered to be a realistic estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, which under probabilistic methodology reflects a 50% confidence level. A high estimate is considered to be an

Back to Agenda

optimistic estimate. It is unlikely that the actual remaining quantities recovered will exceed the high estimate, which under probabilistic methodology reflects a 10% confidence level.

There is no certainty that it will be economically viable or technically feasible to produce any portion of the volumes currently classified as economic contingent resources. The primary contingencies which currently prevent the classification of Encana's disclosed economic contingent resources as reserves are the lack of a reasonable expectation that all internal and external approvals will be forthcoming and the lack of a documented intent to develop the resources within a reasonable time frame.

The estimates of various classes of reserves (proved, probable, possible) and of contingent resources (low, best, high) in these presentations represent arithmetic sums of multiple estimates of such classes for different properties, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of reserves and contingent resources and appreciate the differing probabilities of recovery associated with each class.

In these presentations, certain crude oil and NGLs volumes have been converted to cubic feet equivalent (cfe) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). Cfe may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head.

Encana uses the terms resource play and estimated ultimate recovery, total petroleum initially-in-place, original gas-in-place, natural gas-in-place, and crude oil-in-place. Resource play is a term used by Encana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate. Total petroleum initially-in-place ("PIIP") is defined by the Society of Petroleum Engineers - Petroleum Resources Management System ("SPE-PRMS") as that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources"). Original gas-in-place ("OGIP"), natural gas-in-place ("NGIP") and crude oil-in-place ("COIP") are defined in the same manner, with the substitution of "original", "natural gas" and "crude oil" where appropriate for the word "petroleum". As used by Encana, estimated ultimate recovery ("EUR") has the meaning set out jointly by the Society of Petroleum Engineers and World Petroleum Congress in the year 2000, being those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom.

In these presentations, Encana has provided information with respect to certain of its Key Resource Plays and emerging opportunities which is "analogous information" as defined in NI 51-101. This analogous information includes estimates of PIIP, OGIP, NGIP or COIP and/or EUR, all as defined in the Canadian Oil & Gas Evaluation Handbook ("COGEH") or by the SPE-PRMS, and/or production type curves. This analogous information is presented on a basin, sub-basin or area basis utilizing data derived from Encana's internal sources, as well as from a variety of publicly available information sources which are predominantly independent in nature. Some of this data may not have been prepared by qualified reserves evaluators or auditors and the preparation of any estimates may not be in strict accordance with COGEH. Regardless, estimates by engineering and geo-technical practitioners may vary and the differences may be significant. Encana believes that the provision of this analogous information is relevant to Encana's oil and gas activities, given its acreage position and operations (either ongoing or planned) in the areas in question.

Finding, development and acquisition cost is calculated by dividing total capital invested in finding, development and acquisition activities by additions to proved reserves, before divestitures, which is the sum of revisions, extensions, discoveries and acquisitions. Proved reserves added in 2009 included both developed and undeveloped quantities. Encana's finding and development costs per Mcfe for (i) its most recent financial year (ended December 31, 2009) was $1.62; (ii) its second most recent financial year

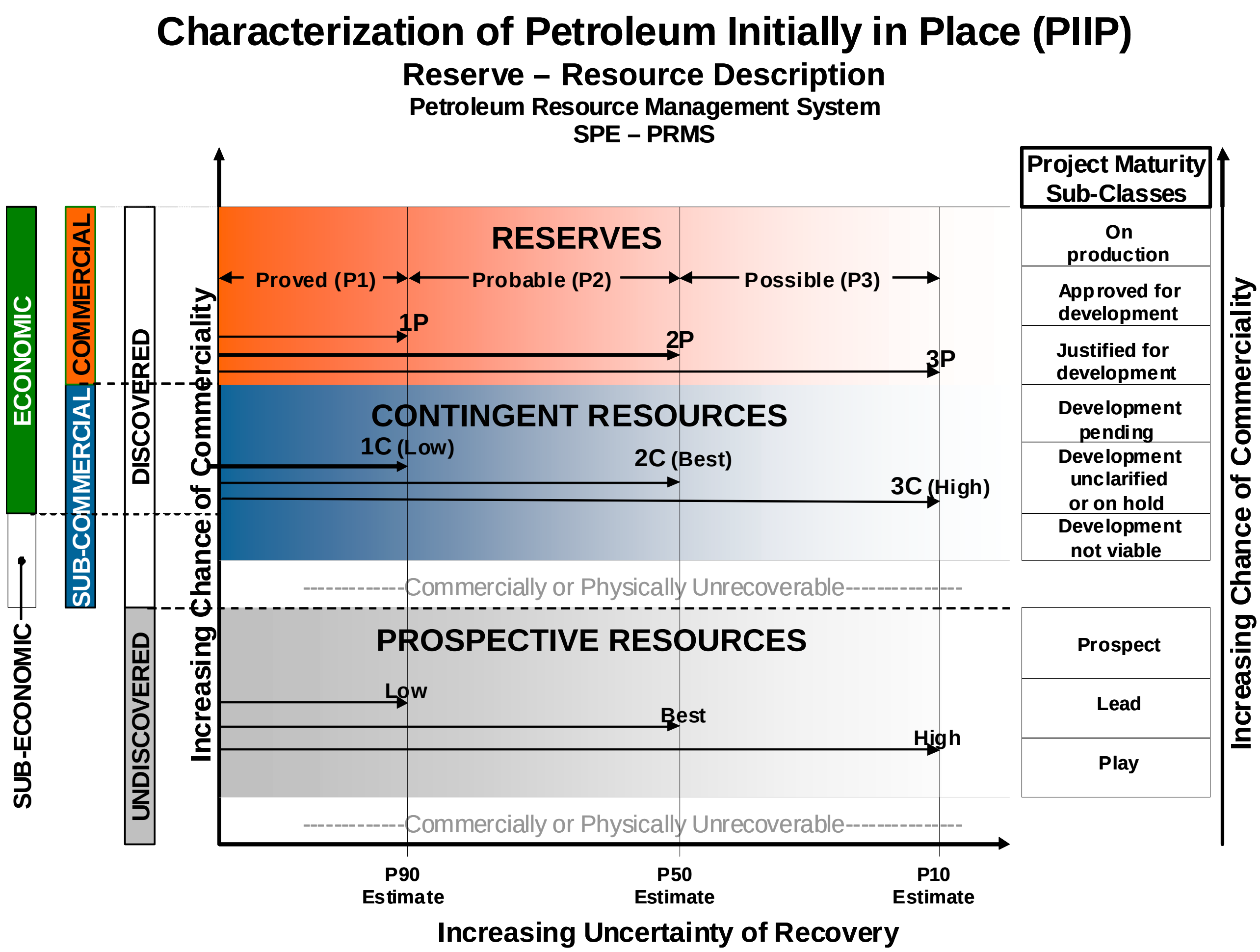
Back to Agenda

(ended December 31, 2008) was $2.50; and (iii) the average of its three most recent financial years was $1.92.

For certain prospects, the Company calculates and discloses a full cycle F & D cost, which is defined to be the estimated total capital investment required over the full economic life of the prospect divided by the estimated ultimate recovery (EUR) of the prospect.

For convenience, references in these presentations to “Encana”, the “Company”, “we”, “us” and “our” may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships (“Subsidiaries”) of Encana Corporation, and the assets, activities and initiatives of such Subsidiaries.

All information included in these presentations is shown on a US dollar, after royalties basis unless otherwise noted. Sales forecasts reflect the mid-point of current public guidance on an after royalties basis.



Back to Agenda

Reserves and Contingent Resources Definitions

The following definitions and cautionary notes are provided to assist investors in their understanding of EnCana's disclosure of reserves and contingent resources. The definitions relating to reserves are those prescribed under the rules of the U.S. Securities and Exchange Commission, which broadly align with the comparable definitions under National Instrument 51-101 of the Canadian Securities Administrators. The definitions relating to contingent resources are those set forth in the Canadian Oil and Gas Evaluation Handbook.

Reserves

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Reserves are further categorized according to the level of certainty associated with the estimates and may be sub-classified based on development status.

Proved (1P or P1)
Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with a reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Probable (P2)
Probable reserves are those additional reserves that are less certain to be recovered than proved reserves, but which, together with proved reserves, are as likely as not to be recovered.

Possible (P3)
Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

Developed Reserves
Developed oil and gas reserves are reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

Undeveloped Reserves
Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Back to Agenda

Reasonable Certainty
If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at lest 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not.

Contingent Resources

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

Contingent resources are further categorized according to the level of certainty associated with the estimates and may be sub-classified based on economic viability.

Low Estimate (1C)
This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

Best Estimate (2C)
This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

High Estimate (3C)
This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

Economic Status
Economic contingent resources are those contingent resources that are currently economically recoverable. In examining economic viability, the same fiscal conditions should be applied as in the estimation of reserves.

Other Definitions:

Natural Gas In Place (NGIP)
That quantity of petroleum (in a gaseous or gas equivalent state) which is estimated to exist originally in naturally occurring accumulations, commonly referred to as original gas in place.

Estimated Ultimate Recovery (EUR)
EUR is those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom.

Back to Agenda

Resource Play
Contained in unconventional reservoirs, resource plays are large contiguous accumulations of hydrocarbons, located in thick or areally extensive deposits, that typically have lower geological and commercial development risk, lower average decline rates and longer producing lives than conventional plays.

Prospective Resources
Prospective resources are those quantities of petroleum estimated, as of a given date to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development.

Cautionary Notes:

Possible Reserves
Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is only a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Particular Property Reserves
The estimates of reserves for an individual property may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.

Arithmetic Aggregation
Where estimates of various categories of reserves or resources for multiple properties have been arithmetically aggregated, statistical principles indicate that these estimates may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual categories of reserves and resources and appreciate the differing probabilities of recovery associated with each category.

Contingent Resources
There is no certainty that it will be economically viable or technically feasible to produce any portion of the contingent resources.

Links

Canadian Oil and Gas Evaluation Handbook (COGEH) – Definitions
http://www.spee.org/images/PDFs/ReferencesResources/Defininitions%20O&G%20Resources%20and%20Reserves%20per%20COGEH%20Vol%201.pdf

Petroleum Resources Management System (PRMS) - Definitions
http://www.spe.org/industry/reserves/prms.php

Back to Agenda

Welcome & Opening Remarks

BILL OLIVER (Executive Vice-President and Chief Corporate Officer, Encana Corporation): Good morning, everyone. My name is Bill Oliver, and on behalf of the entire Encana team, we really want to welcome you all to our 2010 Investor Day. As you can tell from the agenda we have a very full and informative day, and I know when I speak to you on behalf of all the presenters, we are really excited to tell you about North America's newest pure play natural gas company, the new Encana.

We'll begin the morning with a presentation from our President and CEO, Randy Eresman, who will provide a strategic overview of the company, and highlight the strength of our position as a leader in the North American natural gas industry.

Renee Zemljak will then update us on natural gas fundamentals, and we'll follow that with Mike Graham and Jeff Wojahn and their leadership teams, who will tell us about their tremendous assets within the Canadian and the US divisions. Eric Marsh will then wrap up the presentation and the program with his thoughts on the North American natural gas economy.

In addition to our speakers, I'd like to introduce two members of our Executive Team who are joining us today, but will not be presenting. Bill Stevenson, Executive Vice-President and Chief Accounting Officer, and Bob Grant, Executive Vice-President, Corporate Development, EH&S and Reserves.

I'd also like to draw your attention to the back of the room, where you see Ryder McRitchie and his Investor Relations Team, which consists of Lorna Klose, Iska Kolackovsky, Patti Posadowski, and Laurie Urszulan. If you have any questions throughout the day, please see one of the IR team members.

In addition, we've handed out this morning the news release, so if you need copies, Alan Boras at the back would be pleased to provide those to you.

At the end of each of the divison’s sessions will be a question and answer period. We'll have members from our IR Team available with microphones, and so for those who are listening on webcast, please wait until you get a microphone and then ask your question. At the end of the session we'll have

Back to Agenda

the final panel Q&As with Randy, Sherri Brillon, our CFO and Executive-Vice President, Eric Marsh, and Renee Zemljak.

I'll also have to refer you, of course, to the legal advisories at the front of your book. I'd like to draw your attention in particular to the material factors and assumptions in those advisories. In addition, I want to remind everyone that Encana reports its financial results in US dollars, and operating results according to US protocols, which means that production volumes and reserve amounts are reported on an after royalties basis. Accordingly, any reference to dollars, reserves or production information in these presentations will be in US dollars and US protocols unless otherwise noted.

At this point, I want to turn the podium over to Randy Eresman, our President and CEO.

Corporate Strategy

RANDY ERESMAN (President and Chief Executive Officer, Encana Corporation): Thank you, Bill, and good morning, everyone. Thank you all for joining us today. My team and I have been looking forward to this event, and the opportunity to more fully describe our new company to you for what feels like a very long time to us. And it has been. We have been working towards this for the last three years. So I'm very pleased today to be able to finally roll out the new Encana, North America's newest pure play natural gas company with a sharpened focus on what we do best, and that's finding and developing giant resource plays.

The new Encana begins its life with a large and geographically diversified base of low cost producing assets, a huge inventory of low cost drilling opportunities, a value-focused track record, and an opening balance sheet with tremendous financial strength and flexibility. And it's because of the significant increases we've achieved in the size and of the quality of these assets over the last couple of years, that it's become increasingly obvious to us that the greatest value proposition we can make for our shareholders is to accelerate recognition of the value of these assets by delivering a sustainably higher growth rate than we have in the past. And, in fact, we're so convinced of our potential that earlier this morning we announced that we've set a goal to double the production of Encana over the next five years.

Back to Agenda

Our goal today, however, is to help you understand why we've come to this conclusion, and how exactly we plan to execute upon it. So in a snapshot today, Encana is North America's largest pure play natural gas company, with amongst the largest portfolio of low cost undeveloped resources. We're an industry leader in finding new unconventional resource plays, generally at the forefront of identifying and acquiring large land positions before others are aware of their value. We're one of the industry's leaders in creating today's manufacturing approach to the development of unconventional natural gas resources, an approach that has allowed us to consistently be amongst the lowest cost producers. And I'll show you in a few minutes our undeveloped resource base that's easily capable that's of supporting our new growth objective.

In combination with our history of having a disciplined approach of capital spending and financial stewardship, our huge inventory of low-cost drilling opportunities positions us extremely well to achieve strong growth at attractive margins, and to prosper in almost any sustainable long-term price environment.

And so the obvious question is how is it that Encana can be accelerating its growth objectives, while so many others are lamenting over low prices? The short answer is it's all about maintaining margins in any sustainable price environment. We recognized before most others that the natural gas game was about to change in North America. And we believe it has. In the last three years we've seen technological advancements and operating practice innovations applied so successfully in the harvesting of unconventional resources, that these once high cost supply sources have rapidly emerged as mid to low cost in the North American supply portfolio, and Encana has a lot of them.

Encana has been a leader driving many of these changes; changes that target increasing production rates and reserve recoveries, while at the same time increasing capital efficiencies. Technological advancements combining horizontal drilling and hydraulic fracturing have been the key to unlocking these huge concentrated accumulations of shale gas and other accumulations of unconventional sources that respond to the same technologies. The result is abundant, low cost North American natural gas: a major paradigm shift from where we were just a few years ago when most energy analysts were

Back to Agenda

convinced that North America faced unstoppable shrinking supplies, ever-rising prices, and a need to balance the market with large amounts of imported liquefied natural gas. And this paradigm shift has occurred in a very short period of time.

The emergence of these new, abundant, lower cost supplies of natural gas are at the heart of why we believe the natural gas game has permanently changed in North America. We believe that these changes have already had a significant impact on the marginal supply cost to North American natural gas supply, and will result in lower, long-term NYMEX prices in the range of $6 to $7, with short-term prices constrained in a range of about $4.50 to $8.50, based on 2010 cost structures.

As such, we also believe that the best players at this new game will be those companies that can achieve the highest growth rate while being the lowest cost, highest margin producers. At Encana, we're positioned to win at this new game with our huge inventory of low cost assets, and the skill and experience required to play this new game well.

So how do we expect to achieve this new high growth target? It all starts with the size and the quality of our asset base. Encana's built one of the largest natural gas resource portfolios in North America, specifically targeting unconventional resources. Because we entered these plays early, we have amassed large, low cost contiguous land positions in the core of many of North America's best resource plays. Our portfolio also includes large positions at various stages of development in many of the most prospective emerging plays in North America; from plays that we're not ready to talk about, to plays like the Marcellus or Niobrara, where we're in the very early days of evaluating their commerciality, to plays with demonstrated strong growth potential like the Haynesville, Horn River, and Montney, to more developed ones like our CBM, Jonah, and Jean Marie play in the Greater Sierra area.

And very important to our growth objectives, we do not have a single major play on terminal decline. In 2009, we produced 3 billion cubic of natural gas equivalent per day on just 4.8 million net acres of our land base. At a year end 2009, Independent Qualified Reserve Evaluators, or IQREs, I think I should repeat this because I'm going to say it quite a few times, Independent Qualified Reserve

Back to Agenda

Evaluators, or IQREs, estimated that we have approved reserves of 12.8 trillion cubic feet of natural gas equivalent.

And very importantly, we have been increasingly efficient in developing these reserves. Encana's pro forma, finding and development costs was $1.62 per Mfce in 2009, a decrease of approximately 25 percent from 2008, and our expectation is that our finding and development costs are likely to continue to fall in future years as new efficiencies are applied to our large, undeveloped resource plays.

Above and beyond these proved reserves, we have decided to expand our disclosure of our resources in accordance with the frameworks established with the Society of Petroleum Engineers, and in the *Canadian Oil and Gas Evaluation Handbook*. These frameworks provide for consistent methodology for signing economic contingent resources using the same probabilities, forecast price assumptions, and economic conditions as are used for assigning our reserves. It is our view that this expanded disclosure is necessary so that the underlying value of our company can be more fully appreciated. Encana is once again leading the way with a more consistent and comprehensive disclosure than any of our peers.

Now using these frameworks, the IQREs have estimated that our reserves range from 12.8 to 23.7 trillion cubic feet equivalent, and are economic contingent resources range from 16 trillion cubic feet to 58 trillion cubic feet equivalent. And most of this, as you know, is natural gas, I think, in the order of 95 percent.

Focusing in on the low case estimate only, you can see that these high probability contingent resources actually exceed our proved reserves. So assuming a similar reserves to production ratio, which I'm convinced you can, because their decline characteristics are similar to the rest of our producing assets, then we clearly have enough resource base to support our goal to double production.

Also note that this is the second year we've conducted this more comprehensive evaluation with the same IQREs that also evaluate 100 percent of our reserves annually. This, we believe, is the gold standard in reserves and resources reporting. As such, we have a high degree of confidence in the reserves and economic contingent resources assignments that we're now disclosing.

Back to Agenda

On this graph, we focus in on just the highest probability of proved reserves and economic contingent resources. Although these are all really big plays, the Haynesville stands out as having incredible growth potential, but Cutbank Ridge, Piceance, Horn River, East Texas, CBM, Big Horn, and Fort Worth all have a large proportion of contingent resources relative to their proved reserves. These are all areas where you should expect future growth.

I'd also like to highlight for you what differentiates our proved reserves from the low end estimate case for economic contingent resources, and why we think they're estimated size still has a long way to grow before they're fully recognized.

This cartoon map illustrates how the assignments of proved producing, proved undeveloped, and economic contingent resources are made within an unconventional play fairway. The solid orange lines represent, or illustrate the currently producing horizontal wells. The dashed orange lines represent the associated PUD, proven undeveloped locations, and the blue lines represent economic contingent resource locations as would be assigned by our IQREs.

The 1C economic contingent resources meet most of the same criteria as proved reserves. They're economic, and they have the same degree of technical certainty. The major factor that prevents them from being included as proved reserves is that they exceed what is considered to be a reasonable timeframe before they're scheduled to be drilled. As you can see, there is still a considerable amount of land both within and beyond the established fairway, which may, in the future, also be added to these estimates of high probability reserves and economic contingent resources.

What this comes down to for us is that we have a tremendous amount of confidence in our ability to continue to grow our production and reserves at Encana. And as I previously said, we're so confident in our potential that we've set a goal to double the size of Encana over the next five years. Although production in plays like Jonah and Greater Sierra will likely be fairly flat, they're expected to contribute a significant stream of free cash flow over a very long period of time.

Back to Agenda

Within our current plans, we expect some of our more established resource plays, like the Deep Bossier in East Texas, the Alberta Deep Basin, coalbed and methane in Alberta, and the Piceance in Colorado to achieve moderate rates of growth well into the future.

Now our strongest production growth will be achieved from three main plays: the Haynesville, Montney, and Horn River, each of which have the potential to eventually achieve production rates in the range of 1 billion cubic feet per day from our existing land base.

The IQREs have estimated in their highest probability case that our inventory of horizontal drilling locations is at least 1,600 in the Haynesville, 1,100 in the Montney, and 300 in the Horn River. Already a huge inventory, keep in mind that the Horn River wells are longer-reaching, and at an earlier stage of development, and only a small amount of the mid-Bossier has been assigned at Haynesville to date. So there are very likely much more resources to be added at all three of these plays through further delineation and production performance.

Beyond our land and our identified resource base, another major element that gives us confidence that we can achieve our growth objectives is the experience of our people. Over the last several years we've developed and industry-leading, innovative, value-driven corporate culture, focused on leveraging technology and maximizing margins by increasing operational efficiencies every year. Last year, when we faced considerable uncertainty in our business, I challenged our staff to reduce capital, operating, and G&A expenditures by 10 percent, and that was off a total capital, operating, and G&A budget of about $9 billion, and to attempt to achieve that reduction without sacrificing our production in either 2009, or as it sets itself up for 2010. By year end they delivered an amazing 22 percent cost reduction from approved budget, and exceeded our production goal. This achievement, in part, allowed us to strategically redeploy about half a billion dollars to retain additional Haynesville lands, as well as increase cash on hand by about $1.5 billion, putting us in a very strong position to execute on our split transaction, which we did.

This, I believe, is a highly engaged workforce, and our employees have actually requested that the 10 percent challenge be a permanent part of our corporate culture.

Back to Agenda

Now this slide is an example we've shown quite a few times in the past to illustrate just how much improvements in efficiencies our teams have achieved in the last three years alone. A vertical well drilled in the Montney formation and completed with the two-stage fracture treatments, and back in 2006 had initial production rate of about one million cubic feet per day, and the all-in cost of a well back then was about $6 million, and it would've been uneconomic even under the most aggressive price forecast. But at the end of last year, after three years of continuously optimizing all facets of the development processes, and effectively building one of our first gas factories, we began multi-well pad drilling of long-reach horizontal wells, and completed them with 14-stage hydraulic fracture treatments. Their initial production rate averaged over 10 million cubic feet per day, and they cost less than $8 million. That's a 10 times productivity improvement for just one and a half times the cost, or over a seven times increase in capital efficiency over that time period. Encana's Montney wells now meet our economic criteria at long-term NYMEX natural gas prices below $5.

You'll see in here today how these kind of efficiency changes are being employed right across our huge portfolio of unconventional resources.

Encana has also been at the forefront of taking a manufacturing approach to the development of its highly concentrated deposits of unconventional resources. Some of the highest levels of capital and operating efficiency are achieved when we create what we have coined as our gas factories. And a gas factory is created when multiple horizontal wells are drilled, completed, tied in and produced from a single surface location or pad, where we, along with our service providers, can optimize every part of the process. We are at the forefront of employing fit-for-purpose drilling rigs, and 24/7 hydraulic fracturing operations.

Although we believe this is still in the infancy of optimizing the equipment and processes, we've already seen significant efficiency enhancements, and we strongly believe there's a tremendous opportunity for further improvements well into the future. This gas factory approach is a strategy that we eventually expect to employ across almost all of our resource plays, and we're very excited about how this will ultimately play out in lowering costs.

Back to Agenda

And finally, one of Encana's greatest assets is the breadth of our portfolio across North America. This geographically diverse portfolio provides us with tremendous insights into natural gas market fundamentals, which has guided our investment strategy, as well as our commodity and basis hedge strategy. It's one of our greatest competitive advantages.

It is this depth of understanding which has shaped our view that long-term natural gas prices are likely to remain lower and less volatile than previously forecast. And it's also what has enabled us to be at the forefront of many new plays, advancing technologies and techniques quickly and effectively from Texas and Louisiana, to Northeast British Columbia, and back again, finding and deploying the most effective ways to expand and to extract the most value from our resources.

The effect of all these elements is already evident in the robustness of the economics of our portfolio of capital projects, represented by the blue line on this graph, which compared rates of returns for our portfolio versus flat NYMEX natural gas prices.

Our 2010 portfolio of capital projects is expected to deliver attractive returns at long-term natural gas prices well below today's NYMEX Strip Price of about $6 – from a cost to capital return at approximately $4, to a very robust 40 plus percent rate of return at the midpoint of our expected future rice range.

We fully expect that this price range will likely fall over time as lower cost shale gas plays force out more higher cost marginal supplies, and as increased capital efficiencies are deployed. However, industry inflation, or US dollar devaluation could force it the other way. Further, the impact of major government actions could also ultimately impact the price by increasing or decreasing the marginal supply costs.

Our goal will be to maintain or improve upon the margin we receive relative the capital we employ in all price and cost environments. Despite our higher growth objectives, efforts will continue to be focused on being a low cost producer in any price environment. Our target is to achieve a minimum recycle ratio, and that's our netback divided by our finding and development costs of 2.5 times. This is

Back to Agenda

also the recycle ratio target we've set as the midpoint for achieving our performance-based incentive compensation. As such, we believe we are clearly aligned with our investors.

Now back to the basic question of how this growth will be achieved. We expect to build up over time from a capital program of about $4.5 to $5 billion this year, increasing each year as production grows. We expect to achieve the growth in a more capital efficient way than ever before, further leveraging our manufacturing approach to the business. As we grow our production, we expect to take market share from those that are unable to compete. From time to time, we will also continue to sell assets that are not meaningful in our portfolio, and generally, our share buyback program will be used to keep us whole on a per share basis when cash flow delivering assets are sold. What remains constant with our new company and our new strategy is a continued focus on growing value on a per share basis.

And so what does that translate to for future years? Based on 2010 cost structures, and a natural gas price at the lower end of our $6 to $7 long-term NYMEX price range, we expect to steadily build up our capacity to fund and efficiently execute a capital program, which averages about $6 billion per year, by drilling about 2,500 wells per year. Depending on realized prices and expected increases in efficiency, our cash flow generation is, on average, expected to meet or exceed our capital programs.

We'll also be pursuing further enhancements to our long-term growth by attracting and leveraging more third party capital. You can expect to see steady growth from these three areas currently identified as the highest growth drivers of our production in the Haynesville, Montney, and Horn River plays, and we've already started down our new path.

We've updated our 2010 guidance, increasing capital, excluding the impact of changes to foreign exchange, by about $750 million. About $450 million of that is to accelerate our land retention program in the Haynesville. The remaining $300 million is primarily targeted to ramping up development activity. There is also a small amount dedicated to finding new resource plays. The benefit of this additional capital will be more evident by year end when we expect to be producing between 3.4 and 3.5 billion cubic feet equivalent per day.

Back to Agenda

And should our teams deliver as expected, we plan to add in the order of another $500 million to our capital program as the year progresses, and plans are already being put in place for this additional capital, but we've not yet given it our final approval.

We're also on track to divest about $500 million worth of producing non-core assets, and correspondingly, we intend to repurchase about $500 million in shares, or about 2 percent, and we're already well underway. I think we had announced that we had repurchased 0.8 of a percent recently.

While this might sound aggressive if we're trying to exactly balance annual cash inflows and outflows, I'll remind you that last year we held back on our share repurchase program despite selling a net $900 million worth of assets, as we wanted to preserve our financial flexibility while executing our split transaction, and because of the uncertainties related to the recession.

Renee Zemljak, who is up on stage with me, our new EVP of Midstream, Marketing, and Fundamentals, will update you shortly as to where we stand with our hedge book.

As I mentioned earlier, we have a tremendous financial strength. Our balance sheet, credit facilities, and cash flow generation capability will provide us with considerable flexibility to opportunistically accelerate our capital spending in our key growth areas.

Today, our cash on hand and unused lines of credit total more than $7 billion. For the next two years our mandatory debt repayments are only $200 million in 2010, and $500 million in 2011, and the average maturity of our debt is about 13 years.

Despite having such a large amount of financial capability, we will continue to apply our well-established processes and economic hurdles to ensure a high degree of capital discipline in our investment decisions.

Sherri Brillon, our Chief Financial Officer, will join me on the panel at the end of the day. In addition to her role as the CFO, Sherri is also responsible for strategic planning, risk management, and portfolio management; many of the roles she's had for several years. As such, she has a very strong appreciation for the business, and she's learned the value of keeping a pretty tight hold on the chequebook.

Back to Agenda

Our growth plans are based on NYMEX natural gas prices of $5.75 for 2010, and as I said earlier, a range of $6 to $7 longer-term. We've begun stewarding the company based on the bottom end of this range.

Now we have other means of accelerating value recognition from our portfolio. Our Canadian Division President, Mike Graham, and our US Division President, Jeff Wojahn, will highlight for you the success we've had recently in attracting outside investment by farm-in arrangements or joint venture style deals to accelerate value recognition and to leverage returns. We believe that there is a considerable amount of opportunity for us to do more of these development accelerators in the future.

Another part of our capital discipline is that we intend to target a dividend that continues to differentiate our company from our peer group.

And as we look to grow our company, we will also pursue a strategy to grow North American demand for natural gas. We formed a new group under Eric Marsh called the Natural Gas Economy, to look at opportunities where Encana Can be an advocate for increased natural gas use. We realize that there is a huge amount of education of the public that needs to be undertaken before everyone understands the natural gas story in North America as we do at Encana, where we live with it every day.

In this new area of abundant clean burning natural gas, we believe it should play in increasing role as a reliable supply of domestic energy and meeting increasing environmental mandates. Natural gas is cleaner than all of the hydrocarbons. It has a quarter fewer greenhouse gas emissions compared to gasoline and diesel, and about half the greenhouse gas emissions as compared to coal when it's used for electrical generation. But more importantly, natural gas has far less of the toxic pollutants that yellow our skies and affect our breathing. Eric Marsh will go into much more detail on the Natural Gas Economy later this morning.

So I trust I've set the stage for a very exciting story, and the story that Mike, Jeff and their teams will build on as the morning progresses. With a huge resource base in many of the key North America natural gas resource plays, we have the ability to examine and compare project economics, strategically invest in assets with the potential for the highest growth potential and the greatest value creation. Infusing

Back to Agenda

every element of our growth plans is an innovative value-driven corporate culture, focused on maximizing margins by increasing operational efficiencies, and continually striving to be one of the lowest cost producers in our industry. We're expanding demand for natural gas in the Encana tradition of being a first mover, and recognizing opportunities before they become to others. I believe this to be a very exciting time for the new Encana, its employees, our contractors, and for our shareholders. Thank you very much, and enjoy the rest of the morning. I'll see you a little bit later today to wrap things up.

BILL OLIVER: Thank you very much, Randy. Our next presenter is Renee Zemljak, Executive Vice-President, Midstream, Marketing and Fundamentals, and she will give us an update on the North American natural gas market. Renee?

Natural Gas Fundamentals

RENEE ZEMLJAK (Executive Vice-President, Midstream, Marketing and Fundamentals, Encana Corporation): Good morning, and thank you, Bill. Welcome, everybody, to Encana's Investor Day. My goal this morning is that when you leave you have a clearer understanding of Encana's market view of the North American market fundamentals.

Today I'd like to start off the session by commenting on how the North American natural gas market has entered a new chapter. The shale gas mega plays are truly transforming our global energy markets. Over the past decade, the energy markets have been looking for a technological breakthrough in the renewable energy space. Although a technological breakthrough has occurred, it did not occur in the renewables. As Randy mentioned, it has occurred in the unexpected area of the natural gas industry. This technological breakthrough has had a tremendous impact on our natural gas market. We are seeing the cost of natural gas supplies continuing to drop. At the same time, the amount of gas that can be produced is growing dramatically. Most of today's higher cost plays will simply not compete against the mega gas shale plays that will be coming on at a much lower cost.

A tremendous amount of new infrastructure has been added across North America over the past several years, and there is more scheduled to come on line in the next few years to come. The bottom line

Back to Agenda

is this: North American natural gas is abundant, clean, secure and very affordable. Due to these factors, as we go forward, natural gas is very well-positioned to serve a growing share of both North American and global energy demands. Eric Marsh, our Executive Vice-President of Encana's new Energy Gas Economy team will speak to this in much more detail later this afternoon.

Next, we'd like to share with you what our view is on productive capacity in the US and in Canada. This slide shows the amount of gas that could theoretically be produced if the NYMEX prices held steady around $6.50 per MMBtu. This $6.50 price is the midpoint of our expected long-term price range. Please keep in mind that this outlook does assume current cost structures, and it ignores the demand side of the equation.

We have chosen to show our productive capacity growth at a $6.50 price, because we believe that there is an abundant supply available at $6.50, and it also represents an affordable cost for consumers that will ultimately lend towards demand growth in the natural gas sector.

The key messages from this slide are this: the gas supply could grow by about 25 Bcf per day above the current levels by 2020 if the NYMEX price averages somewhere near $6.50 per MMBtu; due to its relatively low cost, gas supply growth will be dominated by the gas shale mega plays that are coming online. Our analysis suggests that the shale gas share of total production will increase from 16 percent in 2009 to a total of 50 percent by 2020. The abundance of relatively low cost resource in North America means that natural gas is very well-positioned to serve a larger share of global energy demand as we go forward.

Due to the resource potential of the shale gas mega plays, we believe that the large scale demand capture in North America is achievable without contributions from Arctic supplies, or significant LNG imports. In fact, we believe that the North American prices will generally be lower than global prices. This will reduce the risk of any large LNG imports entering our market space.

It is our view that natural gas demand capture and growth could be driven from a combination of areas: adopting natural gas as the preferred fuel for power generation, or embracing natural gas as a viable transportation fuel. And furthermore, with these lower, stable prices, we think it is reasonable to assume

Back to Agenda

that North America should be able to re-attract some of the industrial demand that has left overseas over the past decade.

So now I'd like to take an opportunity to focus on North American regional markets. The change in the location of supply growth has had a dramatic affect on the regional markets. The industry's focus has shifted from supply growth in the western plays, to developing the shale gas mega plays in the east. There has been a massive wave of infrastructure investment in the natural gas sector over the last few years. All of the new pipelines and storage fields have caused price spreads to tighten across North America. Encana's portfolio has benefitted greatly from this levelization of pricing spreads.

Due to the industry's focus on eastern shale plays, we currently do not expect the Rockies region to become constrained in the near future. And similarly, we do not expect Western Canadian prices to become constrained either. We expect them to stay well-connected to their neighbouring markets - the Pacific Northwest and the Chicago regions.

We also believe that the Gulf region is very well piped, and poses very little flow or price risk, even in the face of very strong growth from the Haynesville play.

And finally, we believe that the Northeast prices will continue to provide a premium, even with significant growth from the Marcellus play.

This slide summarizes the massive investment in infrastructure that has occurred in North America in the natural gas sector over the past few years. This infrastructure includes long haul pipelines, storage capacity additions and the new emerging shale plays. Due to the infrastructure boom, we expect that roughly 33 Bcf per day of new pipeline capacity, and over 700 Bcf of incremental storage capacity will be added to the pipeline grid between 2007 and 2012. In fact, the majority of this new infrastructure is in service today.

Since 2002, Encana has supported over 10.6 Bcf per day of new downstream pipeline projects. Our commitment to industry infrastructure development serves two primary purposes for Encana. First, our infrastructure commitments ensure that our production will flow even in constrained environments.

Back to Agenda

Secondly, our volumes that are not transported benefit from the price uplift that removing constraints and providing connectivity affords.

To call out one project that is near and dear to Encana is the Rockies Express Pipeline Project that went into service back in 2009. This was the largest pipeline that had been built in North America over the past 20 years. As many of you probably know, this is a project that was initiated by Encana, and we currently have approximately half a Bcf of firm capacity on that pipeline. This project has provided tremendous uplift to Rockies' pricing.

The key message from this slide is that all the new infrastructure has had the primary effect of flattening out price spreads from west to east across North America. Encana has played a major role in facilitating the connectivity of the pipeline grid by committing to firm capacity commitments in a timely manner.

So let's take a look at regional prices. As discussed on the previous slide, over the last few years there's been a massive wave of investment in the North American natural gas infrastructure. All of this new infrastructure, combined with growing supply on the eastern side of North America has had an effect of tightening price spreads across the North American pipeline grid. This slide indicates the regional pricing relationships as a percentage of the benchmark price, NYMEX. The Old Basis World, which is indicated in orange, represents the time period from 2004 to 2008. The New Basis World is represented in the blue boxes and represents the time period from 2010 to 2012. So as an example, if you take a look at the Gulf region, during the Old Basis World, Gulf prices were approximately 96 percent of NYMEX prices. As we transition into the New Basis World, you can see the expectation is for Gulf prices to be approximately 98 percent of NYMEX.

This slide shows that the western supply basins are benefitting greatly by this tremendous price uplift. Most noteworthy is the 19 percent price uplift that the Rockies region has captured as it transitioned from the Old Basis World to the New Basis World.

Through a mix of our equity production, a portfolio of financial basis swaps and our physical transportation commitments, we have diversified our price exposure from our traditional production

Back to Agenda

regions to many markets across North America. In fact, Encana has some level of price exposure to every pricing point noted on the map today.

So the key message is that Encana is extremely well-diversified with respect to the regional price exposures. Encana's portfolio of assets in the Rockies and Western Canada have benefitted greatly from the tightening of west to east pricing.

Now I'd like to take a moment to share with you the status of our most current NYMEX hedge programs. For the balance of 2010, our net revenue and interest volumes are approximately 60 percent hedged at an average price of $6. For the first quarter of 2010, we have realized $165 million in net hedge gains.

In addition, we have a mark-to-market gain for the balance of 2010 of nearly $650 million. We have also hedged approximately 1 Bcf per day for 2011 and 2012 at an average price of $6.50. The 2011 and 2012 hedge programs currently have a mark-to-market value of approximately $500 million. So at current prices, the NYMEX hedge programs for 2010, '11 and '12 are expected to contribute over $1.3 billion to Encana.

So the key message is this, Encana has secured a significant amount of price protection. We will continue to study the market fundamentals and act accordingly.

I'll finish up with some final remarks. Encana relies on studying market fundamentals to enhance our netbacks and shareholder returns. We believe that our size, geographical diversity and upstream institutional knowledge gives us a competitive advantage over many of our peers in understanding market fundamentals. This edge allows us to see market changes years before they materialize so that we can put into place strategies to mitigate our market risk. Mitigating market risk has many advantages for Encana: increasing the degree of certainty of short-term and long-term targeted free cash flow, protecting Encana from downward price pressures resulting from regional constraints, managing capital markets by maintaining certain financial metrics, and finally, these programs allow us to protect Encana's project economics, which are funded by our capital programs.

Back to Agenda

In an effort to mitigate market risk, since 2002, Encana has supported over 10.6 Bcf per day of new downstream pipeline projects. In addition, our hedge programs have realized, on a pre-tax basis, gains of over $6 billion. Approximately $3.6 billion was related to our NYMEX hedge programs, and the remainder of $2.4 billion was associated with our basis hedge programs. We believe that we will be able to maintain our market edge, and continue to provide significant enhancements to shareholder returns for the upcoming years. Encana's approach to price risk management, and our track record of success has served to improve the netback for our entire portfolio.

That's all I have for today. I look forward to your questions this afternoon, and I'll turn the podium back over to Bill Oliver. Thank you.

BILL OLIVER: Thank you, Renee. Now I'd like to call Mike Graham and his team up to the stage, please. I'll just introduce you. I think most of you know Mike. Mike's the Executive Vice-President of the Canadian Division, and joining him today is Stacy Knull, who is the Vice-President of the Clearwater Business Unit, Kevin Smith, the Vice-President of the Fort Nelson Business Unit, and Mike McAllister, who is the Vice-President of the Canadian Deep Basin Business Unit. Mike, over to you.

Canadian Division Overview

MIKE GRAHAM (Executive Vice-President, and President, Canadian Division, Encana Corporation): Great. Thanks, Bill. Great to be here.

Anyways, I'm Mike Graham, like Bill Oliver said, President of the Canadian Division. Just, anybody who doesn't know, the Canadian Division essentially was the Canadian Foothills Division, plus we have the East Coast of Canada as well. So really it kind of entails the Deep Basin of Alberta and British Columbia, CBM and Fort Nelson as well.

And I'd like to say, you know, to me the Canadian Division is running pretty well. We do have relatively low declines, and for us, I always like to say that growth comes fairly easy to us, and it really does. We've been very, very focused around our key resource plays; I'll show you a bit of that, and we do

Back to Agenda

a tremendous amount of portfolio management, and I'll show you some of that as well, as well as the teams.

I'd like to also say that nobody's better positioned for growth in western Canada, and we'll show you that with our big portfolio. So we think we're going to have, you know, strong growth 2010 and beyond, if you will.

Okay, some of our strategic focus, some of the keys for us, you know, safety really is job one, and we talk a lot about that. Mike McAllister here, he always likes to say if you can't do it safely then don't do it, and it really is our mantra. We've been putting a lot of people through safety courses, you know, in the field, in the office. We put something like 750 people through over the last year, so we're trying to change the culture throughout.

Technology is also moving very quickly; you'll see that today. We've been quick to embrace it, and you know, really want to ensure that we do have the lowest supply costs. Our wells are getting longer, we're going to show you that, and our fracs are getting bigger, if you will.

Also, continuous improvement; it keeps costs moving down. And essentially where we can, we have load levelled our programs. Like Randy said, we're drilling 365 days a year now, we're fracing our wells now 24/7, and you know, it really does provide for some great efficiencies if you're doing it that much.

Also, supply management is a key part of our business. We like to say we've got competitive tension in every dollar we spend, and we have been locking in more services, services around drilling, completions, snubbing, cementing. Right now in western Canada things are pretty quiet, and we've been locking them in over the last several months at pretty good rates, if you will.

We do have a big land position; an enormous land position, something like 9.3 million net acres, and we do have - you can see sort of from this slide - big contiguous blocks. And really, Renee alluded to it, but we did enter these things before the masses arrived, so our entry cost was very, very cheap on those.

Back to Agenda

We do a lot of farm-outs, we do a lot of dispositions, we've done a lot of swaps, and like I say, we're very, very focused around our care of the key resource plays.

Okay, Stacy's going to talk to about CBM and the Horn—or sorry, and the Horseshoe Canyon as well shortly here. Kevin Smith's next, and is going to talk on Greater Sierra and really focus around the Horn River, and then Mike McAllister - we did a switch here a couple years ago and Mike now has all of the Deep Basin of Alberta, and the Deep Basin of British Columbia, so what we kind of call Bighorn and Cutbank Ridge, if you will.

Okay, this is the lifecycle. We've used this quite a bit in the past, and it really does show that we've got assets kind of across the entire spectrum of the lifecycle, if you will. Mostly, you know, relatively early life plays, if you will. The one that is in sort of maintenance mode, a little bit mature, is the Jean Marie. We do, you know, Kevin produces about 200 million cubic feet a day there, and we think we can kind of keep that flat over the next 10 years by drilling about 50 wells a year.

Stacy thinks he can double the CBM now from about 300 to 600. Mike's going to show you Cutbank Ridge, you know, where we're presently producing about 350, and we think we can go over a Bcf a day, and Randy talked about that. As well, Bighorn, you know, that's the Deep Basin of Alberta where we're a little over 150 million cubic feet a day there, and we're going to go up to over 500 there. As well, the Horn River, and we think, you know, we hardly have any production today in Horn River. I think Kevin's going to show you about 15 million a day. We're going to exit 2010 at about 100, and we think we can take that right up to over a Bcf a day as well.

And some of these plays are still very early. If you look at the Mannville, and as well, parts of the Horn River and the Montney, we've got big land positions there and we don't have a lot of wells there. We do have tremendous resources on our lands. We think we've got natural gas in place on Encana lands of about 300 Tcf. Our proved reserves are right around 6 Tcf, and our contingent resources a little over 20 Tcf. And today we produce about 3 Tcf off our lands, so about 1 percent of our original gas in place, so you can just see sort of the scale of that.

Back to Agenda

Like Randy talked about, we have been working hard to determine our contingent resource, and we're pretty darn comfortable around that now. Like he said, the IQREs have worked on it for the last couple of years, and we're finally rolling it out this year. But I know the teams and kind of through our unbooked resource potential, you know, over the past probably five or six or seven years, we are getting pretty darn comfortable.

Like I say, proved reserves is about 6 Tcf now, and our 1C contingent, the one we're most comfortable with, is about double that. 3C resource, 21 Tcf, you add it all up together, our 3C, 3P and we're close to about 30 Tcf. We produce about half a Tcf a year, so we got a tremendous life in front of us; 50, 60 years on that.

And this next slide shows our tremendous resource potential where it is. Cutbank Ridge is really the big one at about 10 Tcf, and that's mostly around the Montney formation. We still have a lot in the Cadomin. We still have a lot in the Doig as well. And we - you can see from this one - we've got a lot of contingent resource in the Horn River, but we haven't done a lot of bookings to date, if you will, so Kevin's going to show you that. But, you know, we're going to have good bookings out of the Horn River. We're going to have a pretty good finding and development cost going forward. We think we're going to be in that order of about $1.50 going forward.

And we still have lots of land, say, in the Horn River, or in the Montney where we don't have any contingent resource, and that's just because we haven't drilled any wells there. We've got something like 1,100 net sections in the Montney; we've maybe got a third of that that's on our contingent, and maybe somewhere around a half on the Horn River. But like I say, it's just we don't have any wells there.

Now this one's our snapshot of our huge drilling inventory. Stacy says he's got 13,000 locations in the Horseshoe Canyon. In the Montney, the Horn and Sierra we have sort of 15 to 25 year drilling inventory, if you will, and that's just on our 1P and our 1C contingent resource, so we're very conservative. We have been looking for ways to accelerate the value capture, if you will, and we've done a lot of farm-outs, and I'll show a little bit on that.

Back to Agenda

We do have top quartile supply costs, and our supply costs are moving down. Each and every year our supply costs continue to move down just with our efficiencies.

We're going to drill somewhere in the order of about 130 deep wells this year, and then about 700 coalbed methane wells, essentially about 5 percent of our inventory on our 1C and our 1P.

Now growth. We've had pretty good growth performance, especially out of our KRPs, and you can see that here. Over the last several years, dated back to about 2005. On the conventional side, we continue to sell it, we continue to produce it out, and our conventional resources have really went from about, say, 50 percent in 2005, down to about 10 percent today. Our portfolio is becoming more like Jeff's now, and mostly unconventional, if you will.

And we've had strong top line growth, and you can see where we're at in 2009. We came down in 2009. We had a lot of curtailments due to the low price in the order of about 118 million cubic feet a day, and then dispositions as well. In 2008 we actually sold about half a billion dollars of conventional resources. 2009 we sold about a billion dollars out of Canada, or close to about 100 million cubic feet a day. But our key resource plays still continue strong growth of about 13 percent.

We’ve got strong growth coming for 2010. We think we're going to exit close to about 1.5 Bcf a day, and really, if you look at it sort of a year exit to exit, that's about a 30 percent growth. So we're starting out at a lower base due to the dispositions, but we're going to have tremendous growth throughout the year. And, you know, we've been doing a lot of work around our long-range plan, and we think we can still grow in about the 10 to 15 percent per annum.

Okay, our well costs have been coming down, and our well costs on a per frac basis as well continue to come down across our resource plays, and our BUs are very focused on this. They want to ensure they've got the lowest cost structure, and they continue to drive, you know, down costs through efficiencies, through load levelling, and economies of scale.

Our teams, I've got to give them a lot of credit. They've been doing a fantastic job. And like I say, we're pretty much load levelling where we can right across the division, and it really does give us the lowest supply costs. We have a lot of partners; some areas in the Deep Basin, you know, and in the Horn

Back to Agenda

River now, and as well—and just about all of our partners, they do tell us that we have the lowest cost structures in the business, and so we're very proud of that and we're going to continue to work hard at that.

We also continue to employ horizontal technology. Technology, like I say, is moving very quickly. If you see the horizontal, it's amazing where it's gone over the last five years. Our drilling team's doing a tremendous job. You know, we got in the Montney and the Horn and we were drilling about 1,000 metres, now we're 2,000, 2,200 metres, and sort of beyond, and it's really incredible where it's going. And the fracs; the fracs continue to get bigger and bigger, and we're—you know—we're fooling around sort of with the spacing just trying to make sure that we've got the appropriate spacing.

This increases our IPs, you can see from here, and our EURs throughout our KRPs.

The Horn River's a great example of this, and Kevin's going to show you the Horn River. I still say it's relatively early in the Horn River. We've only had wells on now for three years or something like that, Kevin, but we think Kevin's going to have recovery north of 15 Bcf a well, and that is a tremendous amount of EUR per well, probably double any other resource play in North America.

And this one shows our 30 day IPs. Remember, 30 day IPs, a lot of our peers in the US will give you that one day sort of number, but these are 30 day IPs. Now, we're kind of over 5 million cubic feet a day in the Montney, and in the Horn River over 10 million cubic feet a day. Remember, a 30 day average, if you will.

For 2009, this is how our budget works out. Our production was about 1.3 billion cubic feet a day. We sold about $800 million net between our land sales and what we bought, but about $800 million US, and our net capital without Panuke was about 700 million. So here you equate that, we had free cash flow in the order of about $2 billion for 2009, so tremendous amount of free cash flow generation.

For 2007, remember we sold about 100 million cubic feet a day, so we're going to have growth of about 3 percent. But it would be over 10 percent if you could add in, again, those dispositions. But exit to exit, very strong with 30 percent growth, getting close to about 1.5 Bcf a day.

Back to Agenda

We are going to drill more wells. That's mostly around the coalbed methane. And our operating costs, you'll notice this, our operating costs in Canada were a little bit higher than what they are in the US, and that is just because essentially we own all of our own midstream in Canada, so it does provide us with a little bit better netback. But if you look at our operating costs, again, they're really top quartile, you know, amongst our Canadian peers.

Now, I want to talk a little bit about our portfolio management. And I know we've been farming out things probably for a decade now. We've farmed out a tremendous amount, and we do have, like I say, we've got a huge land position; you know, close to 10 million net acres, and just over the last few years we've really focused in on it. We've done a tremendous amount. I know the US guys are doing a tremendous amount as well, but it really kept our joint interest teams, and our corporate A&D very, very busy helping out there as well.

Over the last two years, we've essentially farmed about $2 billion worth, and that includes Kogas, which we just signed at the end of February, and that's for $565 million. Already in 2010, if you include Kogas, we've got about $650 million committed on our lands. That would equate to about 700 wells being drilled on our lands, and an additional 60 if you include Kogas.

Just want to show you a little bit on the Kogas joint venture. You might've seen Kogas' press release. We didn't really press release it, but it looks like this. Kogas is going to spend $565 million over three years, and essentially they spend $100 to earn $50, if you will. You can see on the Horn River, we farmed out about 12,500 net acres, which is about five percent of our Horn River assets. That's what they're going to earn. And you can see that on the Montney lands it's the deepest part, so we're getting into the very deep Montney, if you will, at about 3,500 metres. Tremendous gas in place in the Montney, and we're pretty excited about it, but it works out to about nine percent of our Montney lands. It's about 65,000 net acres to Kogas, but it's, again, only nine percent. We've got just a huge, huge position.

And Encana's going to operate this, so that does give us a lot of advantages going forward. So I think it's really a win-win. You know, for Kogas, they're going to learn a lot from Encana, and a real good

Back to Agenda

win from Encana as well. We're going to get some stuff that really has no contingent resource on it developed.

And like I say, we've done a couple additional farm-outs for about $100 million as well, and we're going to do more. We have an enormous land position that allows us to do a lot of farm-outs.

Okay, so we've looked a bit on western Canada, we're going to go way, way over to the East Coast. I don't think Dave Kopperson's with us today, but Dave actually looks after the East Coast of Canada. Panuke's moving along pretty good. Most of our capital really has been spent. We've got about $300 million left to spend on Panuke, and the bulk of that is going to be spent in 2010; a little bit in 2011. Now originally we thought it was going to cost about $760 million. There has been some, you know, FX, and a little bit of inflation and just some stress around that, so we're about $800 million now on the capital program.

In our production, we talked a little bit about this in the last quarter. We've actually moved our production start date back from end of 2010 to probably around mid-year 2011. We still plan to bring it on in that 200 to 250 million cubic feet a day, and we do have firm capacity in the order of about 200 million cubic feet a day on the Canadian side.

So the reason it's delayed is the production field centre. You can see it here; a schematic of it. It's just a little late coming out of Abu Dhabi. We do have what we call the Rowan Gorilla III, so it's the big jack-up rig out there working for us now. We have completed our disposal well, our injection well, if you will, and the rig's moving off now, and we've got to do our four recompletions to finish that off.

So that's really all we have to do. We've got to put the production field centre in place. We've put our pipeline to shore, it is finished now. We have to do the inner field pipeline, and put the production field centre in place. So we're excited. Panuke's coming on in mid-year 2011, and it will be good to see. It's been a long time coming.

Execution now, I just can't stress how much execution, and like I say, our business unit, and our teams are masters at execution. Supply management is an integral part of our business. We do a tremendous amount. We aggregate our spend. We do a lot with the US around steel. We've got what we

Back to Agenda

call our desk set up. We've got a steel desk, we've got a capital equipment desk, we've got a transport desk, we've got a camp desk, and we've probably got a few other I'm forgetting. But anyways, we really aggregate a lot of spend there. We kind of focus that in, and it really does allow us to be very, very efficient on our spend.

We have been working closely with our suppliers. We work closely on developing new technology. We really were the first ones out of the gate to build these fit-for-purpose rigs, and we've had some of these rigs in our fleet now under contract for well over five years. And we're looking, Bob Johnson and his team, the drilling guys and the completion guys are looking to do more even around the fracing equipment. Like I say, we've extended a lot of our contracts. We've recently been out snubbing, cementing. You know, we're looking at fracing, we're looking at drilling, extending our contracts even further, and we are getting pretty favourable rates in Canada. You know, things have been relatively quiet in western Canada.

Continuous improvement. Like I say, we're fracing 24/7. Kevin may go out and frac a Horn River well. It may take half a year to frac. He'll put in over 350 fracs off one pad. We're doing two and three a day, so you get pretty darn good at it. And we do a lot around logistics, be it moving water for these big fracs, moving sand; a lot of concurrent operations as well, so I can't stress that enough.

Encana, we have been working closely with the Alberta and BC Crown. Richard Dunn and his team - Richard heads up what we call our government relations in Canada. He really does a fantastic job, and he's just absolutely tenacious about it.

BC's done a good job on their policy. 2009 they brought in a couple things. They gave us two percent royalty for one year. It's going to end sort of mid-year this year, and they made some permanent changes for the good on their deep program as well.

And a big one for us, in 2009, BC brought in what they call their Net Profits Royalty, so they're going to give us a two percent royalty on Horn River, and it's ring-fenced, so similar to a lot of the oil sands projects. We're going to pay a two percent royalty on Horn River for quite awhile as we develop that, probably for over 10 years, so a great job by BC.

Back to Agenda

Also, Alberta. Alberta in 2009, they announced their five percent royalty over a couple years, and you may have seen, last week we were over at the McDougall Centre, and the Premiere announced their competitive review results, so they did a good job. You've got to give Alberta credit. They kind of backtracked a lot that they had done in the past in the new royalty framework. And there's no reason, you know, we feel western Canada, there's no reason it should be declining. If you look at lower 48s, we're growing 10 percent. Western Canada's been declining say at 10 percent plus. We have the Horn River. We have the Montney. These are big, what did Renee call them, super, mega shale plays, or mega shale plays, but they are enormous plays. They're as big as the Marcellus, they're as big as the Haynesville, they're as big as the Barnett, and they really are world class plays.

This just shows, Ed Stelmach and Ron Liepart, the Energy Minister. But it was, you know, really, really positive for Alberta in the Deep Basin to Mannville. They gave us the five percent royalty upfront, permanent; five percent for a year, or half a Bcf, and 36 percent on the top end when gas prices get very high. And they're going to do a lot around Smart Regulations, Co-Mingling. They've done some on that down spacing; stuff around CBM, so good job. This really was—will ensure that, you know, Alberta remains competitive in North America.

It is a competition for capital. In Alberta now they're trying to take BC's natural. They want to be the most competitive oil and gas jurisdiction in North America, so that really makes us happy on that one as well.

Okay, in summary, in the Canadian Division we do have a great portfolio. Through our long-range plans we still think we can double our production easily over the next five years, as long as we get the costs - or as long as we get the capital, and Jeff doesn't hog all the capital. We continue to drive down our costs, and we're very, very relentless about this. The teams will show you some of that. We're active in portfolio management. We've done a lot of dispositions, we've done a lot of farm-outs, you know, more of this to come in 2010, and we are excited about the future. Like I say, growth comes easy to the Canadian Division, and Encana.

Back to Agenda

That's it for me, and I think Stacy's going to come up next and show you the CBM. Thanks. Stacy?

CBM

STACY KNULL (Vice-President, Clearwater Business Unit, Encana Corporation): Well thanks, Mike. That was a great opportunity overview. Welcome, everybody, to Investor Day. I hope you're excited and interested in what we have to show for Encana. The opportunities are amazing, and you're going to get more details as the business unit leaders like myself come and express some of this.

My name's Stacy Knull. I have the distinct pleasure of looking after the Clearwater Business Unit, which includes the CBM resource play for Encana.

So what do most people want out of their investment? I look at it as high growth, low risk, and being a little green doesn't hurt. The Horseshoe Canyon CMB play is really just that. It's a high growth potential. We've had 59 percent compound annual growth rate historically on the play. It's low risk, with predictable infill development, and really, it's one of the most environmentally benign fossil fuels that exists today.

The Horseshoe Canyon is the greenest of the fossil fuels; mostly methane, all sweet. It is gas that's cleaner than what you burn in your furnace today, and your hot water tanks. The Horseshoe Canyon CBM has little to no water production, is low flowing pressures, lower than the pressure tip that flows into the metre at the side of your house. And then it's in the farmland of Alberta, so low surface impact, and that's one of the favourable things of CBM, where it is developable.

This is our production since 2005. We started this play in 2003/2004, with really zero production, and we've grown it to about 320 million cubic feet a day today. It exists, as I said, in the heartland of Alberta, on a land base that's 83 percent fee land. Fee land is where you pay no royalties. We've had this land since the late 1800s. Low land expiries. That gives us a great advantage over Crown and freehold lands that you'll see in a lot of our competitors. And really, the timing of the development is ours to do as

Back to Agenda

we see fit in the balance of the portfolio. There's really no artificial timelines that are imposed upon us on development of the CBM.

There are over 12,000 CBM wells producing in Alberta, at about 750 plus million cubic feet a day. Encana has about 6,000 of those wells, and we're producing, as I said, about 320 million cubic feet a day. In the CMB Fairway, Encana has a very enviable position; 2.1 million net acres on the land, and an estimated 12 Tcf of natural gas in place.

The Fairway on the Horseshoe Canyon CBM play is very well-defined. Most of the sections in the core area have a well drilled. The remaining wells that make up the full development scenario are really infills from there, as we move this thing from four to eight wells to some places, even 16 wells per section. This makes this a very predictable asset, and it's also, as I said, very scalable for Encana as it sees fit.

Our total Fairway natural gas in place is 84 Tcf for our industry, and Encana has 12 Tcf natural gas in place. Our 1P and 1C resource level, our conservative level on this, we have about 13,000 more locations to develop on this. Our best estimate though, we have about 15,000 locations, and over 3,000 recompletions on deeper conventional wells that we can go uphole and convert to Horseshoe Canyon CBM and integrated sands.

In 2009, although our evaluators lowered our PUDs to be in line with the Securities and Exchange Commission rules, and nearer to our five year development PUD schedule, our evaluators and ourself believe that we have potential 2 Tcf to book in the future years on this play.

You'll be seeing a lot of horizontal talk on the shale plays, and they're amazing plays; awesome plays. And it's really the horizontal technology has come along where it looks like they're producing multi-wells out of a single wellbore.

In our integrated Horseshoe Canyon CBM well, we're similar in a way, although we're vertical, but we sometimes produce over 40 zones into a single wellbore, maximizing the value and efficiency of this play. Natural gas in place of this play, that I talked about, the 84 Tcf, the Horseshoe Canyon CBM, if you include some of the serendipity sands we have in between these coals and some of the deeper sands

Back to Agenda

that we can integrate and comingle with this, you can have almost 120 Tcf of natural gas in place in the fairway.

We've been doing more and more sand completions and recompletions with our CBM. In fact, as we continue to comingle and integrate our sand, last week with our coalbed methane we perfed and tested the Belly River Sand. It would be in the package we could bring on, and it was a 4 million a day Belly River Sand that we'll bring in with the coalbed methane. So the potential economic uplift on these sands as you bring them with the coalbed methane is really, truly great.

This is a graph that represents our opportunity created by the 13,000 wells of our 1P and 1C resource. The production is represented as wedges, and the capital as bars. Our full development plan calls, as I said, for about 15,000 plus wells as we develop this, and really at a conservative rate of about 1,000 wells per year, that we've had a history of drilling anywhere from 400 to 16,000 wells per year. We could double our production in 10 years on this great play.

As I stated earlier, we have 3,000 recompletions along with that 15,000, so very important as we comingle some of the conventional production and move it with the Horseshoe Canyon. This is a very scalable program for Encana. It gives this company ample flexibility to steer the program. It's a great foundation to help build a high-growth company. This play continues to shallow the decline we believe the CBM play could produce for over 40 years, with a long life decline of three percent.

This graph illustrates our supply costs associated with the 1P, 1C drilling inventory. Our full development plan, again, calls for 15,000 best estimate wells, and all of these very competitive with a supply cost of $4 or less. While these supply costs are very competitive today, we continue to look for ways, as Randy and Mike mentioned, to drop these supply costs; lower them and continue being competitive, and continue looking for funding opportunities for this.

These two graphs show, one, our drilling and completing tie-in costs over the years, and two, how long it takes for our CBM wells to go from rig release to on production. Remember, we have sometimes 40 different zones we have to complete in these single wellbores to bring on the efficiencies of these plays.

Back to Agenda

We continue to be more efficient and utilize new technology to drive our costs down on this play, load levelling, doing more when other competitors and companies are moving out of the area. Long-term planning with technology advancements is another way to drive these supply costs down. Along with adding sand opportunities, comingling with the CBM costs, continuing with the CBM costs, cost reductions and production reserves increases will help this play continuously improve. These will always allow us to bring our supply costs down to lower levels.

This is a graph of our production gains using another new technology that we've just used in the last year. This allows us to better stimulate the coals for a 50 percent cost savings on stimulation. The production technology results in more coals being stimulated for a better production rate.

Our CBM zones are not fracked, as you'll hear a lot in the other areas. There are significant natural fractures in the fabric of the coal already. What we do is provide nitrogen down there in a stimulation fashion. We just take the nitrogen from the air you breathe stimulate the coals with it. So it's naturally fractured and has a lot of opportunities to move forward.

Horseshoe Canyon has one of the lowest impacts on the land of the gas development of any area, with the least amount of risk. Low disturbance leases continue to help us maintain to our social license to operate with stakeholders; very environmentally benign. We're even working with our Gas Economy Group that you'll hear about later, to provide more clean burning natural gas vehicles within our business unit, which is good for the environment, and is good for us.

Mike talked a little bit about this, but this map depicts our core Horseshoe Canyon fee lands in the centre outlined there, and surrounded by a large fee land base that's on some of the conventional type plays we've had in the past. With a lot of the fee land in our business unit, we're always working on getting value for these lands. As a mineral rights owner, if we lease out the conventional lands, we receive royalties on other operators' production. It was one of the reasons why in 2009 we had one of the highest netbacks of any business unit in Encana. Deals on our conventional lands, like Hoadley asset, where we can sell the current production for top metrics, really, we believe, and farm out the mineral rights allows

Back to Agenda

us to participate in the upside with no capital. We get paid in royalties and maximize the value for all shareholders.

Well, that's it for me on the CBM summary. I hope you enjoyed this overview of CBM KRP. It's a value creator; scalable growth depending what the company sees fit, and again, a very low risk and huge value.

I'm now going to turn it over to Kevin Smith, and he's going to show another one of the largest shale plays in North America in its early development, the Horn River. Thank you.

Horn River & Greater Sierra

KEVIN SMITH (Vice-President, Fort Nelson and Canadian Unconventional Gas Exploration, Encana Corporation): Thank you, Stacy, and good morning, everybody. My name is Kevin Smith. It's my pleasure to talk to you today about the Fort Nelson Business Unit, and the Greater Sierra key resource play. The image here is of our Horn River main camp, and in the background you can see a rig drilling on a multi-well pad, and the area of development is actually named after that lake in the background called Two Island Lake.

The majority of my comments are going to be on the Horn River this morning, however, I think it's fair to recognize the Jean Marie as still being a key part of the Greater Sierra key resource play.

So Greater Sierra does consist of two main and distinct play types; the Jean Marie, which has been a staple of the KRP for over the past decade, and then the Horn River. In the Jean Marie, Encana has been the dominant player, holding over 1.5 million net acres in the Jean Marie, and in 2009, we actually reached a very significant milestone in that we produced our very first Tcf of gas from the KRP, and the majority of that did come from the Jean Marie.

The production over the past several years has been fairly constant, with a slight drop in 2009 related to the shut-in strategy that Mike spoke of in the third quarter. Going forward on the Jean Marie, a strategic mix of targeted investment, joint ventures, and potential divestitures will maximize the value of these assets.

Back to Agenda

The second play type, of course, is the Horn River Devonian shales, where Encana has established a very strong position of 260,000 net acres, in what we believe to be the core of the play. And with our partner, Apache, we have led the pack in advancing development of this very attractive play.

We exited 2009 with 13 gross wells producing approximately 31 million a day of gross raw production, of which 24 million a day of that was related to the last five wells that we'd completed in 2008 and 2009. In 2010, our plans have us completing 44 gross wells to achieve an exit rate of around 100 million a day net to Encana. Our business unit objectives really are built around a culture of safety, efficiency, continuous improvement, and bottom line of growth and value creation.

As I mentioned, the Jean Marie and the Horn River are two plays making up the KRP. I thought it would be good to kind of show where they fit on the lifecycle of the resource play. Horn River can be characterized as early development as we execute our program in the Two Island Lake area, and also as a piloting phase as we begin our Kogas joint venture in Kiwigana. In fact, because we're not largely driven by land retention, the delineation of the Horn River acreage will take place over the next four years, as we're only required to drill 22 wells outside of our development program to keep our land position together, which is, I think, a distinctive advantage of the land tenure position that we've got here relative to what we've seen at a lot of the other areas with fee lands.

The Jean Marie has passed its primary development phase, however, as Mike mentioned, there's a strong inventory that still exists that we can maintain our production with a modest two to three rig program.

In the Jean Marie, a focus of continuous improvement and disciplined execution led to some of the best metrics ever achieved in the play, and last year we delivered a supply cost of $3.78 per MMBtu, so not bad for a play that is this far into its development.

We have employed our best fit-for-purpose rigs. We've moved to drilling multilateral wells on multi-well pads. These concurrent operations have allowed us to use natural gas for underbalanced drilling, and so now instead of flaring the gas while we drill, we're actually producing that gas down the

Back to Agenda

pipeline, and that does have a significant uplift in our metrics. With the inclusion of the BC Government's royalty incentives, you know, we've been able to drive our supply costs below $4.

Now onto the Horn River. With our estimate of just over 500 Tcf of natural gas in place in the Horn River Basin Devonian shales, we estimate about 94 Tcf are in place on Encana lands. We estimate that natural gas in place per section of anywhere from 150 to 270 Bcf per square mile on our lands. And we're early in the development of the play, but at this point, to the end of 2009, we have already been able to book 170 Bcf approved reserves, and we've got a range of contingent reserves from a low end to high end estimates of 1.2 Tcf to 6.7 Tcf. And as Mike spoke to before, further delineation and establishment of new development areas, such as Kiwigana, will allow these reserve and resource estimates to grow as the contingent estimates that we've got are currently limited to areas where we've got existing production.

Based on our current low and high contingent resource estimate, we have an inventory of 600 to 1,500 gross wells in the Horn River. Included in that Horn River contingent resource estimate is probably about—approximately about 1.2 Tcf of reserves and resource within the net profit royalty ring fence in which we'll be subject to a two percent royalty until project payout or 10 years, whichever comes first. And so this is very significant. The forward-thinking program implemented by the BC Government has really helped close that location disparity between the Horn River and other North American large mega shale gas plays.

Our approach to determining optimal development led to a down spacing pilot in 2009, and the blue production profile that you see here, that represents the performance of our 2008 ten-stage completion in the B-C76-K well, and represents essentially what we would call an infinite spacing relative to offset wells and what the rock itself would perform at. The performance of this well shows that the average forecast on a per interval basis, so taking the production and normalizing that to the number -- to a single interval is just over 1 Bcf raw per stage. So an estimate then on that well of about 10.5 Bcf total for the well.

The grey profiles in the background then represent the performance of the four well pilot that we did in the downspacing pilot in 2009. The orange profile is the average of those four wells, and this pilot

Back to Agenda

tested eight acre spacing, so essentially a 900 foot inter-well distance with 375 feet for each interval. We have 14 frac intervals in three wells and 12 in the fourth, and what we've seen is these wells are performing as expected, and we looked into 2010 to develop on the same density. We're going to be drilling longer laterals, however, so therefore we're developing more reservoir by adding stages and basically keeping the same subsurface development density.

The 2010 wells we expect will average about 21 stages per well and the resultant type curve will yield 16-19 Bcf of raw gas recoveries per well, assuming each interval has a range of recovery from 0.75 to 0.89 Bcf.

The technology advancements have been significant in the Horn River. Two Island Lake we've really very quickly, almost by necessity because of the existing infrastructure, moved into a full manufacturing approach. I think this is well ahead of a lot of the other North American large shale gas plays. This has been driven by large gas in place per section and the ability to drill long reach horizontal wells. From a single surface location, we've been drilling up to 16 wells per pad.

In addition to multiple wells per pad, we've been increasing the length of the horizontal section, so in early 2009 we were reaching about 1600 metres on our horizontal reach, and this year we're actually drilling to 2200 metres and sometimes even longer. These incremental lengths have allowed us to develop more acreage with the same surface footprint, and we've increased our frac count from 14 last year to as many as 23 occurring in 2010 on a single well.

For the single pad, we're developing over four square miles of reservoir, with approximately 350 fracs per pad. Our completion operations typically commence once the drilling rig has moved off and we will in a continuous 24/7 hour fashion, we will commence operations and pump up to four fracs a day with a goal of averaging three. That amounts to almost four months of continuous fracing on those pads as we develop them.

Another significant advancement is the use of subsurface non-potable water for fracing. In the next few weeks we'll be commissioning our Debolt water treating plant to really become the primary frac fluid that we'll be using at Two Island Lake, and then step out development from there. This water source

Back to Agenda

will have sufficient capacity to meet those four fracs a day and it has the added benefit of dropping in half our water cost for fracing.

Speaking of costs, our cost performance has been notable. We've seen our cost drop dramatically as we moved into the manufacturing process. From a drilling side, we've reduced our total cost on a per metre of horizontal length distance. So if we look on that basis it's really comparing our total drill costs relative to how long the lateral is on a per metre basis. We've dropped that by 45 percent from almost $2900 per lateral metre to under $1600 lateral metre, through an integrated approach, team approach, better bit selection and then applying continuous improvement practices.

On the completion side, our performance has been even more impressive, having dropped almost 70 percent to a forecasted completion cost per interval of $340,000 for 2010. The main drivers here are more fracs per pad in 24 hour operations, we're able to spread out the fixed cost over more fracs. And also, having an inventory of fracs ready to pump is huge because we avoid the non-productive time. If we have an issue on the well we've got another well ready to pump without having to shut down operations. And then the Debolt water, I've already mentioned, has been a huge contributor to reducing cost.

This is, again, I think is another demonstration of resource play execution at Encana. It shows the lease boundary capital cost. So basically, the drilling, completion, and well site equipment is included in that, and we're normalizing that on a per frac interval basis. We've dropped from $4.3 million in 2007 through the early evaluation portions of the program, to a forecast of $540,000 in 2010. The corresponding F&D then has dropped from almost $7 to $0.87 in Mcf, and we've really been able to do this through better efficiencies and higher recoveries per well.

This map here highlights the development going on here at Two Island Lake program where in 2010 between Apache and Encana, we'll drill 41 wells and complete about 44 wells. So that's about 800 fracs that we'll be completing this year on four pads. As you can see, there's a considerable amount of acreage on the map on the right to develop, and over the coming years we will begin new operating areas, such as at Kiwigana and as we do our delineation programs, we'll be teeing those up for new development areas.

Back to Agenda

There's been a significant commitment made here around increasing the treating and transportation capacities in the Horn River. On the treating side, Encana has led a group of Horn River producers within the construction of the cabin gas plant. It's a greenfield gas treating facility, with a capacity of 800 million cubic feet a day. In fact, on Friday, last week, we received all of our final permits to proceed and the initial phase of 400 million a day is scheduled to be onstream in September 2012.

In addition to those projects, Spectre Energy has begun reactivating about 600 million a day of idled capacity. They've also made application to construct another 250 million a day Fort Nelson north plant, which is going to be in the same area as our cabin plant. And then to really access more markets and be better tied into the North American market, TransCanada Pipeline has made expansion application to drive their system up into the cabin plant area, and that's going to benefit us in the basin by having access to a postage stamp tolling.

So it's clear that the Greater Sierra key resource play is shifting gears into a new growth platform. We're very excited about the potential we see, the position that we have and the execution performance that's been demonstrated in this early point in development in the Horn River. The team does remain focused on providing a safe, value-added growth and to pursue opportunities to enhance the competitiveness of our assets.

And that's it for me. I'm going to turn it over now to Mike McAllister, and thank you for your attention.

Cutbank Ridge & Montney

MIKE MCALLISTER (Vice-President, Canadian Deep Basin Business Unit, Encana Corporation): Thanks, Kevin. As you can see, the Fort Nelson business unit, under Kevin's leadership, has been doing just an excellent job in creating our newest resource play in Horn River. I'm Mike McAllister, as Kevin mentioned, the Vice President responsible for Encana’s Canadian Deep Basin Business Unit. Actually my responsibility for the Deep Basin goes back to 2003, with the inception of the two unconventional resource plays in Cutbank Ridge and Bighorn.

Back to Agenda

The picture on the slide is one of our Montney gas well leases near Dawson Creek, British Columbia. Starting with the map on the left, the Canadian Deep Basin Business Unit spans both Northeast British Columbia and Northwest Alberta. Highlighted in the red ellipses are our two key resource plays, namely Cutbank Ridge located primarily in British Columbia and Bighorn resource play located in Alberta. As I'd mentioned, these key resource plays were really initiated back in 2003. When we started transforming our asset mix for the business unit, which was called Grand Prairie at the time, from a series of smaller convention pools to two very large and very competitive deep basis resource plays.

Today, our land base is almost 1.9 million acres, with 83 percent of those lands being located within the resource play areas. Encana was an early entrant into both resource plays, therefore our land acquisition costs, as Randy mentioned earlier, were very, very competitive. Our cost, for example, in the Montney, was $750 per acre, which is very low when you compare that to 2008 when the industry land prices peaked at $13,600 an acre Therefore, Encana acquisition costs were 18 times less than the average acquisition cost for the industry at that time. The business unit operates 1,800 producing wells with 630 million a day of processing capacity, which we own and operate.

The chart on the right shows the aggregate key resource play production growth from 2004 to 2009, growing from 100 million a day to 500 million a day, or a 32 percent compound annual growth rate. Of note, in 2009, we chose to shut-in 92 million a day annualized average net revenue interest, which was not included in the chart. As well, not included in the chart, in 2009, 65 million a day of conventional production from our conventional assets.

As the business unit name suggests, our two key resource plays reside in the Deep Basin, focused on gas saturated tight sands. The map on the left shows the depth contour of the Cretaceous Deep Basin, with our focus area being, like, the gas window, shown in red. The map on the right is an isopach, showing the Montney Deep Basin reservoir thickness ranging from 150 feet on the east, to 1,000 feet on the western side of the play. The natural gas in place for both fairways in aggregate totals 1,100 trillion cubic feet equivalent, and on Encana lands we have mapped out greater than 200 Tcfe. Therefore, in aggregate, we believe we have captured 18 percent of the resource in the two fairways of our focus. The

Back to Agenda

matrix on the bottom of the slide shows our reserves and resource estimates, being 2.4 Tcfe for proven reserves, with a 1C contingent resource of 2.6 Tcfe. However, we believe that 1P plus 1C totalling 5 Tcfe, is a very conservative estimate, being only 2.5 percent of the 200 Tcf that we have mapped out on our lands. To further demonstrate our ability to grow and the opportunities that we have in front of us, our technical teams have identified 4,000 drilling locations, with 2400 of those locations currently having supply costs of less than $4.

Moving and focusing on the Cutbank Ridge, here's the natural gas in place map for the Cutbank Ridge Montney, with gas in place ranging from 20 Bcf per section in green to greater than 120 Bcf per section in red. However, the natural gas in place we've got up to over 300 Bcf per section as we move out to the very western flank of Cutbank. The regional Montney fairway shown in the map covers 475 townships of land, with 170 townships being what we call the highgraded fairway, shown by the blue polygon. Within the highgraded fairway, Encana has acquired 1,100 sections or 700,000 acres of land, capturing 165 Tcfe of gas in place. The stratigraphic column, shown on the left, shows the Montney reservoirs being a shale, as defined by the British Columbia Ministry of Energy and Mines. However, the majority of the Montney formations in the fairway are fine grain sand or silt, with a TOC of approximately one percent. The Montney shale content increases to the northwest, as shown on the map, where you'll see TOCs of up to eight percent, however, in that area you'll see nano-Darcys of permeability.

In our core focus area, in Dawson Creek, Montney gas is relatively sweet, with an average H_2S content of 700 parts per million, ranging from zero percent H_2S up to small pockets of 0.8 percent H_2S. With respect to industry activity, today, currently there's 48 drilling rigs drilling in the Montney; seven of those are operated by Encana. Industry is currently producing 700 million a day; Encana represents 300 million of that out of the Montney formation.

On this slide, we have the key development areas of our Montney assets, with the lower Montney producing formation shown in blue, and the upper Montney development area shown in orange. We're fortunate in our core area of Bissette to have both upper and lower Montney, doubling our opportunity in

Back to Agenda

each section. The north/south dashed line on the map is the Montney Deep Basin edge, as defined by a 40 percent water saturation, which essentially overlays the transition from conventional normally pressured Montney to the east, to an overpressure greater than 0.45 PSI per foot pressured gradient on the west hand side. Out in the very west, we'll actually get to a 90 percent overpressured situation -- or 90 percent overpressured, I should say, with pressured gradients of 0.82 PSI per foot.

On the right hand side, we show our Montney type log. As many probably know the story, our first initial stages we're developing the Montney we tried vertical wells, back in 2005 timeframe. With rates of return of about 13 percent there was no way we were going to compete with the rest of Encana’s portfolio, so, therefore, we're basically taking lesson from the Barnett Shale, we tried four frac horizontal wells in early 2006, and realized we'd get four times the rate with the four times the EUR with only 20 percent increase in cost, thus unlocking the economic potential of the Montney resource play.

Consistent with what you have heard and will be hearing with Encana’s other key resource plays, the Montney development is really a story of continuous learning and continuous improvement. We have tested greater than 10 different completion designs since the start of the play, reducing our supply cost year-over-year. Today, the completions of choice in the upper Montney is case hole jet perforating and a sand plug design, and in the lower Montney, we are using open hole packers and frac doors for our horizontal frac diversions. The standard length in 2009 of a horizontal leg was 1,650 metres, with 9 fracs. Also, in 2009, we pilot tested two long horizontal legs completions drilling out to 2,400 metres or 7,900 feet, and completing with 14 frac stages, with the result being our best wells to date with an IP of 13 million a day and an EUR of 10 Bcf. That's raw gas. The per frac drill, complete, and tie-in cost was our best yet, at $540,000 per interval, which resulted in a lease edge supply cost of $2.46. Again, our best yet. We're extremely encouraged with this result and looking forward to opportunities to fully adopt this program as we move forward.

I'd like to just take an aside, with respect to our Montney development BC, the British Columbia regulators allow for good engineering practice, something that's kind of unique to the play areas. Whereas, if you, for example, own all of the Montney rights in a township, which is what we do, we can

Back to Agenda

get GEP (Good Engineering Practice), which allows us to downspace to whatever level that we feel is economically feasible, as well as we can cross-section boundaries. We're not limited by any sort of spacing regulations when it comes to GEP approval, which gives us a real economic advantage in the Montney.

The chart on this slide shows the Montney per interval cost performance on a year-over-year basis, with the drill complete and tie-in costs from 2006 to 2009 and our forecast for 2010. When we consider our vertical wells in 2006 essentially cost us \$3.2 million to complete one interval, and compare that to 2009 performance, where our cost has dropped by 80 percent to \$650,000 per interval, delivering the same per frac type curve and EUR per stage. These step change cost reductions were achieved through increasing frac count per well, with improvements in technology such as our frac designs and with improvements in procedures achieved through load-levelling our rig fleet and load-levelling our frac spreads. Commensurate with the per interval cost reduction, our supply cost with our horizontal wells have decreased by 50 percent, from 2006, which was \$6.43, down to 2009, which was at \$3.38.

I'll now move on to our Bighorn key resource play. Shown on the slide, is our natural gas in place map for the Bighorn Deep Basin Cretaceous fairway, where we have gas in place ranging from 20 Bcf per section in green, to greater than 120 Bcf per section in red. Of note, all the gas we're producing in Bighorn key resource play is sweet and relatively high C3 plus liquids, with contents ranging up to over 25 barrels per million. Our core development areas are shown on the map on the lower left, starting with Aurora, Ansell, Carrot Creek, Resthaven, Kakwa and Red Rock. We believe we have captured 40 Tcf of gas in place on Encana lands and the Deep Basin Cretaceous fairway.

In the Bighorn resource play, when we refer to the Deep Basin Cretaceous, we're actually talking about a series of stack formations, both channel and marine sands, as shown on the stratigraphic column to the left hand side of the slide. In fact, in Bighorn, we pursue the entire stack of Deep Basin Cretaceous formations with up to 20 zones per well. Many of these sands were not pursued in the past, thought to be too tight, with porosities ranging down to 3 percent from 12 percent and permeabilities ranging out to one microdarcy from a millidarcy. On the right hand side of the slide, we have a type log from one of our

Back to Agenda

Kakwa wells, where we completed nine zones in this well, I should say, with six frac stops. When you're spending money to complete all the formations in the stack, it's very important that we understand all the zones are actually producing and contributing to the value of the well.

Encana has worked with Schlumberger to develop a very cost effective technique called distributed temperature sensing (or DTS, for short). This technique is used to measure the amount of gas each completed zone is producing in our vertical well bores. Essentially we run a temperature log in our vertical wells and are able to calculate gas rates from each of the producing zones correlated to temperature changes in the well bore. Not only is DTS confirming that we are generating value from each frac stop, but we can also confirm that we are getting gas production commensurate with natural gas in place supporting our proven reserve bookings and contingent resource identification, as shown by the pie charts of the right hand side of the screen. This technique, I think I mentioned cost effective, this technique cost us about $50,000 per well. We don't do this on every well, we select the wells we're going to do it on, but it cost us about $50,000 per well. For our standard production logging or spinner logs on the same well would cost us $300,000. So essentially a quarter million dollar savings per well. As well, this production -- or this information from the DTS survey has really helped us optimize our frac designs, where in the Falher, for example, we've been able to triple our production rates from our original test using DTS data.

Similar to Cutbank Ridge, here's a chart showing our year-over-year continuous improvement of the Bighorn cost, with the blue bars showing our average well cost to drill complete and tie-in per year. Well costs have been reduced by 35 percent from $7.5 million in 2006, to $4.9 million per well in 2009, with a planned reduction to $4.7 million per well in 2010. In fact, we're a little under that right now. This step change cost reduction has been achieved through a series of technical and procedural improvements, with fit for purpose rigs, pad drilling, load-levelling our drilling rig fleet and concurrent completion operations.

As shown on the chart, we also have an orange line that shows that we have a 30 percent drop in lease edge supply costs, dropping from $5.03 in 2006 to a forecast of $3.50 in 2010. The focus is on continuous improvement, so looking further -- for further improvements in developing our Bighorn resource last year we pilot tested a half dozen horizontal wells in the thicker, higher natural gas in place zones, which we encounter, as shown in the strat column on the right hand side. We are very encouraged with the initial results shown on the bottom of the slide, as one of our wells are 14-28 Falher horizontal well, which was completed with nine frac stages, and it's producing eight million a day, essentially flat after 60 days. With respect to inventory of horizontal wells we have in Bighorn, we've identified 700 locations that we could apply for horizontal well technology.

No business is sustainable if the integrity of its operations are not managed well. As is the story with all of Encana's business units, safety and environmental responsibility receives a lot of attention in the Canadian Deep Basin. In 2009, our recordable injury frequency, which is a measure of many people we hurt on our worksites in a given year, was only 60 percent of the industry average, and 22 percent lower than our previous year's performance. Our flair volumes were reduced by 30 percent year-over-year, and our spill volumes were reduced by 67 percent year-over-year.

So, in closing, the Deep Basin Business Unit with its performance track record and a 4,000 well inventory is very, very well positioned for not only growth but continued supply cost reduction as we move into the future. That's all I have to say. Now, I'll turn it over to Bill Oliver for the question period.

Canadian Division Q&A

BILL OLIVER: Thank you, gentlemen. We will now open up the floor for questions. Please raise your hand and we'll have a microphone coming to you. So, some questions for the panel?

A remarkable job that we've got right here.

UNIDENTIFIED SPEAKER: Just regarding the reserves on the Horn River, can you explain how those reserves are determined, given the type curve we saw was only about half a years or six months? Is it cut off at an economic limit? Is it cut off by time? And how much of those reserves are produced, for example, beyond kind of a seven year timeframe? Just maybe explain some background behind the 0.8 Bcf per frac?

Back to Agenda

MIKE GRAHAM: Okay. Well I think I'll turn that one over to Kevin. But I can tell you now, we've had the wells on probably for about three years, so we are getting pretty comfortable around -- like I say, it's still early in the Horn River, it's still early in the Marcellus or the Haynesville for that matter, and it's going to take quite a bit of time, but our type curves are definitely when you do the decline are kind of pointing towards that. So like I say, it's very early yet. Kevin?

KEVIN SMITH: So, you know, usually, the proof in your quality reserve estimates is your IQRE is actually giving you positive revisions year after year, and that's what we've seen. Mike is absolutely right, we've got a number of wells now that we've got about three years of production on. And one thing that's characteristic that we see in the Horn River is that the decline profile of our wells and the wells that we've also done data swaps on, are very consistent and so that provides some confidence in the decline character that we see. What we have booked as reserves, certainly on a proven developed producing basis, for 2009, we expect to see positive revisions on that as we look at the data going through the year and I think that the IQREs are using accepted practice for the level of confidence with those, and so as we move forward we expect to see those PDPs also grow as well as mature with more data.

MIKE GRAHAM: It may, just, if you look at Kevin's chart there, it's shown on your right, it points out the six months of production, but that was just kind of, you know, put the time scale from the same basis for the 2009/2010 wells and 2008 wells. And really, some of those wells have been on for three years, we just don't show the full data. All we wanted to do is compare sort of 2009 to 2010 and the bigger fracs, and just to ensure that we're getting consistent, at least over that initial, you know, six months for 2010.

MIKE GRAHAM: Like I say, it's very, very early and obviously if you discounted out a long ways, you know, Kevin's shown up to 19 Bcf for some of those wells. That's, you know, definitely yet to be seen when we've only got maybe three beats out of some of the wells to-date type thing.

BILL OLIVER: Right. Next question?

BRIAN SINGER: Hi, thanks. Brian Singer from Goldman Sachs. Two questions. First on the Horn River Basin, you mentioned that 21 stage frac is being planned for this year, is that your view on the

Back to Agenda

21 stages being the optimal number of fracs for the Horn River Basin on a going forward basis? And where are you in the process of finalizing that? And then, secondly, on Bighorn, can you talk a little bit more about the horizontal opportunities, especially in the cardium and cadomin and what is included in some of the resource numbers that you've put out today?

UNIDENTIFIED SPEAKER: I'll take the Horn River question first. So, if we take a look at the 21 fracs average for our new wells in 2010, it's based on the same development density as the four well pilot that we had conducted in 2009. The difference is that we are extending the reach of those horizontal laterals. We're not actually increasing the frac density within the well bore; just developing more reservoir with it and adding on to those. We do apply some risk on those numbers as we add more length to the well. The additional -- some of the additional fracs are also coming from -- we're recognizing that we're entering the Muskwa Water Park at an angle and we're leading some of the reservoir through the build uncompleted, so we are adding heel (phon) fracs into our program this year as well.

UNIDENTIFIED SPEAKER: Mike, do you want to talk...

MIKE MCALLISTER: So with respect to the horizontal drilling opportunities in Bighorn, we used a ten metre 20 Bcf per section cut off as being an application in that zone for a horizontal well. With respect to the cardium and the cadomin, actually most of the inventory I've been talking about would not reside in those two zones. We're looking more at the Dunvegan, the Falher, for example. You know, you're probably thinking about the cardium oil potential and the horizontals that are going on there, we're looking at that opportunity. We haven't fully evaluated it right now.

UNIDENTIFIED SPEAKER: Yes, Brian, you know, a big part of our business really is we do a lot of farm-outs, and Mike talks about the cardium oil, today the cardium oil is just going crazy and, you know, it's really, really popular. We do have a lot of land with cardium oil on it. We have farmed out a lot of it already to certain companies and we're looking to really farm out more of it and so it's not unlike sort of in these plays that really heat up, you know, we do have big inventory in a lot of places and we'll look to farm out when we hit the opportunities.

Back to Agenda

RICHARD: I got a question about access to oil field services. As you execute your programs and build out production, is there any limitation on oil field service providers to meet your own objectives? And what kind of cost implications might that bring to your supply cost from the oil field service providers overall?

MIKE GRAHAM: Well, that's a great question, Richard. You know, inflation obviously it would kind of -- you know, really running rapidly, the sort of the mid 2005 to about 2008, and slowed down a lot. In 2009, we'd probably see quite a bit of deflation. At least in western Canada, we're predicting inflation in about the one to three percent over next year, and we don't see a real big problem in western Canada. Right now things are actually relatively quiet in western Canada. They're starting to heat up a bit with the oil. We don't use a lot of fracing equipment because we'll use two or three frac units and we'll run them 365 days a year, 24-7, where we can. Same thing around the rigs, we use our rigs, like I say, we've done five year fit for purpose contracts around these rigs, and we're looking to extend some of those as well. So right now it doesn't look too terribly bad in Western Canada. I think it's a little bit quieter than maybe some of the places in the US and so we're in pretty good shape for the immediate future. We will look to do some longer term contracts around -- especially around fracing equipment, because, you know, essentially all the fracing equipment today is set up to move by track from one frac to the next to the next, but in the areas like the Horn River, or even the Montney, you know, we can skid mount these things and we can put the fracing units up there year round, if you will. So we're looking at lots of opportunities like that as well.

BILL OLIVER: Okay. Any other questions? Thank you. Let's take about a 15 minute break and come back at 9:40 or 10:45, and we'll get the US team up. Thank you.

BILL OLIVER: All right. I think we're ready to start with the USA Division. Leading off will be Jeff Wojahn, who's our Executive Vice-President & President of the USA Division. Joining him today is John Schopp. John is the Vice-President of the North Rockies Business Unit & New Ventures; Darrin Henke, Vice-President of the South Rockies Business Unit; and Danny Dickerson, who's the Team Lead of East Texas & North Texas. Over to you, Jeff.

Back to Agenda

USA Division Overview

JEFF WOJAHN (Executive Vice-President & President of the USA Division, Encana Corporation): Well, good morning, everybody. I'm Jeff Wojahn, and thank you for coming today. I'll try to be as entertaining as Mike; that's a hard act to follow. I know that the IR folks will try to keep me on my script here because I'm known for rambling on. But it's my time on the podium, so I'm going to say what I want. So, maybe I can entertain you a little bit here today.

As far as format for today's presentation, I'm by and large going to go through a similar format in the slides that Mike went through on his, and hopefully that'll give you all an opportunity to add up the numbers and to consistently evaluate the different resources that the company has. As far as my team's concerned, we thought we'd maybe switch topics a little bit for you, and John Schopp is the Business Unit Leader of New Ventures, and he's going to talk to you a little bit about how do you find the next Horn River shale play and what characteristics are involved with identification of these new opportunities across North America. Darrin Henke, our Business Unit Leader for South Rockies Business Unit, their business unit by and large invented or coined the term gas factory. Now, they used it in a little bit different application than we are today in shale gas. The application was primarily derived around tight gas development of the Pieance, but the thought process, a lot of the simultaneous operations, a lot of the drilling of 60 wells per section, and the like, came out of Colorado, originally, and we've been able to transfer a lot of that knowledge across the company. He's going to talk to you a little bit about the future of gas factories and what makes them tick. And then finally, Danny Dickerson is going to end our show today, and he's going to talk about what I know all of you came here to talk about, and that is Mid-Bossier and the Haynesville. Certainly for us, it's a thousand pound gorilla in our budget and our strategic plan, and he's going to give you more insight. So, on with the show, and we'll kind of run through these slides.

First, and foremost, like Mike and like all of our operation teams, safety is the utmost of importance and our top priority. We realized we were granted a social license to operate in the communities surrounding our resources, and both protecting our people and the environment, is key to maintaining a successful relationship with all our stakeholders.

Back to Agenda

Our aggressive growth, as I'd mentioned before, will be supported in our current portfolio by and large by the Haynesville Shale, although many of our other traditional key resource plays will also support that and many of those plays in themselves have significant upside beyond what we've represented today. Advancing shale gas technology is a key to maintaining or enhancing profitability and growth within our asset base. Some of the tricks we use, obviously, and, you know, you've heard this already from the Canadian teams, is we focus on reservoir characterization, and I think John's going to talk a lot of about that, advancing horizontal drilling, completion optimization and cost efficiencies.

So here's a standard slide... you know, maybe I'll back up a little bit and talk about the evolution of the US Division. Back in 2000, Randy challenged us all to say, you know, find us the next Suffield, find us the next Southern Alberta tight gas resource, move forward and look at Wyoming and see if we can identify those opportunities. So in May of 2000, we did the acquisition of a company called McMurray in the Jonah field – it has basically been, I think, the best acquisition the company's ever done, and we'd started from zero in 2000; today, we're pushing two Bcfe a day, ten years later, and have, in my mind, one of the strongest resource asset bases in the industry. I don't think anyone in the industry has matched our performance. I say that with a great deal of pride. When you look at where we are today, you can compare us to XTO or Chesapeake, or EOG or any of these companies, and I'll put our record against them that we've beaten them. And that's a strong statement, but I truly believe that it's something that we're all proud of at Encana, and, you know, clearly, when you look at our performance, our history, it's absolutely been amazing. And again, something that we're all very proud of.

Looking more directly on the chart in front of you, last year was a year where we weren't thinking about growing our production base; we were thinking about whether the debt market would come back, whether the free market would continue to work as we saw, and we really were into capital preservation, cutting costs, curtailing, or, in some cases, shutting in our production and surviving. We have a little bit better optimistic view today, thankfully, than we were a year ago, and we've brought back most of our production and we resumed growth in our key resources plays, and, again, kind of expanded our capital budgets beyond where we are.

Back to Agenda

Looking forward, we plan, for the remainder of the year, to grow our production by around 15 percent. We basically stopped last year. Actually, our production was declining a little bit, as we preserved capital and moved forward. On a year-over-year basis, it didn't, because, you know, the year before that, in 2008, we came off at 21 percent growth, so we had 21 percent growth, still had annualized growth, but really we were moving back down. Now we're turning it around as smoothly as we possibly can and we're anticipating 15 percent growth in our plan for the upcoming year.

We'll move to the next slide please. Okay. Here's our key resource play lifecycle that Mike showed earlier in his presentation, and I think a couple of points. We have a few mature assets, Jonah being a ten-year-old asset that's now at ten acre downspacing, we're not going to talk a lot today about. I think most of you know that asset pretty well. We have other, what I'll call mid-life assets. East Texas, where we had very, very rapid growth over the last three or four years, 350 million a day. The Piceance Basin, where, we call it mid-life only because we've been working at it for ten years. Really we have a very, very significant contingent resource opportunity there, and very significant potential shale resources as well that could drive it to being one of our, you know, back to very full development. But when you really look at our portfolio, we've got a very strong portfolio of essentially potential or contingent resources at early stage development. We're going to talk a lot about the Haynesville and Mid-Bossier today, but we've got a full inventory of very exciting opportunities that we're not going to get to today because of time, but also because of confidentiality reasons. But the point is, we have a lot of stuff that we can work on, whether it's the defined contingent resource, which I'm going to be talking about in detail in the next couple of slides, potential resources, or defined assets that we can drive cash flow to grow with.

Okay. So the next three or four slides, I'm going to talk about what we have, and Randy's already kind of rolled it up, but I'll break it down for you in a little more detail. This table provides a summary of the recent evaluation conducted by IQREs. This work recognized 18,000 economic well locations. Now, we don't drill Horseshoe Canyon wells in the US. Our wells are deep wells. So when I talk about 18,000 wells, put it in the context of the 456 wells we're planning to drill this year. This is a lot, 35 years of development, if we were to drill all of our contingent resources. Now, of course, we're not going to do

Back to Agenda

that. That's beyond our financial capability. What we're really going to do is focus on our low risk, PUD drilling and our low risk contingent resource drilling that provide us the best economics and the lowest supply costs.

So this graph shows that breakout of 1P, or proved reserves. That proved reserves has about a 40 percent PUD contingent within it, and 1C, or contingent resource. Now, both 1P and 1C, and this is an important point.. Randy said and I think Mike said, and I'll say it again, are economic, with a 90 percent certainty, so the definition of 1C really has the same robustness as proved reserves. But, it's out there in our planning cycle, outside of our line of sight. That doesn't mean we're not going to drill it, we're going to make strategic decisions to drill it above our PUDs, but it really has the same certainty. In many cases it has similar supply costs as well. The orange bars are almost twice the size of the blue bars. Not quite, I'm exaggerating, but our 1P is 6.9 Tcf and our 1C is 10.4 Tcf, so adding those two bars together is 17.3 Tcf. That's enough stuff to keep us working, developing with a very, very high degree of certainty for well over a decade at our current capital pace of development.

Now, if you think back to the graph on the lifecycle, our early life plays had relatively low proved reserves, but significant contingent resources, which is to be expected because of the level of effort and understanding of the type curves that we have. However in plays that are a little bit more mature than our portfolio, like East Texas and Piceance, have roughly as much contingent resource as proved reserves, and that used to be my old rule of thumb on whether you could have a sustainable growth plan in the future. If your contingent resources are -- or your 1C is equivalent -- or, you know, in the old days we used to call it undeveloped resource potential, was equivalent to your proved resources, and we have that and more, even in our mid-life assets. And that's an important part. So even though we aren’t going to necessarily emphasize those plays in great detail today, they are still growth assets in the company. And obviously with technology and optionality around these plays associated with resource development, you know, I could envision them being high growth plays in the future.

So here's a breakdown on the resource size and how it affects well inventory. As you can see, we have just in the 1P, 1C case, you know, I kind of think of those together because of the same level of

Back to Agenda

certainty, 7,600 net wells. So I talked about the big inventory, now this is the more defined inventory, and again, at our current pace of development, our inventory life exceeds 15 years of drilling. I talked about the full 3P, 3C case at 35 years when you hone down to the high certainty case, we're still talking 15 years of drilling. In the next five years I'm not even worried about it from a resource point of view. We have it; it's established, it's known and we're going to be moving forward with that development. Also, our current inventory supports a very low average supply cost. And here's another part, we've got those 7,600 net wells, we have high certainty around them, but they also have low supply cost or expected supply cost when our IQREs model those. Averaging somewhere around $4 per MMBtu, and as you can tell, there's significant development between $3 and $4, so, you know, the bar's been set. I talk to my teams and say, "If you've got a new play that you don't think will have full cycle supply cost below $4, forget about it. Don't even talk to me." That's the new world that we're in. And ultimately, that is what we need if we're going to meet that 2.5 times recycle ratio that Randy's talking about in the new natural gas market.

Now, one of the things that I think Encana has a tremendous advantage over others is to be able to adapt, and when we have such a diverse portfolio, like Encana has, it allows us as portfolio managers to optimize capital structures and move capital when things change. The advantage we have is that at Encana is, we can react to regulatory and other changes, we can reallocate our capital in a smooth way, we can anticipate regulatory or cost structure changes or technical changes and optimize where we're going to move our capital in that ever dynamic, ever evolving environment that we live in. And I think that's one of the biggest advantages that we have.

So, here's all our bars in total, moving to a 3P, 3C inventory, totals 51 Tcfe, and that doesn't even account for the emerging plays and some of the thought processes we have in our group. It makes you wonder why we're exploring still, but I think one of the reasons why we do and one of the reasons why I talk about the 3P and 3C cases is because three years ago, our cost supply costs in the Haynesville were a glint in our eye. They change. Supply costs change weekly. And so what is 3P, 3C today might be 1P, 1C tomorrow, and that certainly happens. We didn't talk about the Haynesville three years ago when we discovered it. We talk about it now when we're producing 220 million a day going to 600 million a day

Back to Agenda

exit. That's when everybody says, "Oh, what a great play that is," but the reality is, these things are dynamic because they change with all those evolving dimensions that I'd talked about earlier.

Now, with this slide, 51 Tcfe, obviously, there's an opportunity for us to look at joint venture partnerships. Mike talked a little bit about it, Randy talked a little bit about it, to accelerate development and plan new technologies to either move C3 into C2, C2 into C1 or C1 into P1 or recategorize our assets or potentially add to those totals. And I'll talk a little more about that. Let's go on to the budget this year.

Okay. Budget overview - see that big dark blue wedge in the bottom, that's the Haynesville. It is the thousand pound gorilla that occupies our time. Zero to 220 million a day in 24 months and moving to 600 by the year-end or 500, depending on our mid-stream services tie-in. We have a three year plan for land retention in that play. We're in year two. We talked about 50 wells the first year, 100 wells the second year, 100 wells the third year; that's about 150,000 acres of our portfolio, over 450,000 acres in the play, so we’re really only talking about a third of the land. Some of it is held by production, some of it is fee land, so we're not worrying about it all, but we're worrying about the stuff that's getting top leased under our current leases at $10,000 an acre.

And I must say, those, all those wells that I quote -- when I talk about wells, I'm talking about net wells, so we're actually drilling 200 wells in the Haynesville with our partner, Shell, about 100 wells net to Encana. So, we're going to talk -- Danny's going to talk in great detail about it and talk a little bit about the Mid-Bossier and some of the results and the continuous improvement in there. But it's not to say that our other assets don't occupy a positive sense in our portfolio. Things like the Jonah field, we continue to have first and second -- or second quartile performance on that asset. Amazingly, we're drilling five and ten acre downspacing there. East Texas, if anyone of you ever heard me talk, East Texas is my favourite place. It's a box of gas with the most phenomenal geology that I've seen in the entire industry. We haven't really focused on it as much. We've got five or six rig programs working in the Deep Basin, but we've barely scratched the tight gas and shale potential of that area. We will, once we get them done with the Haynesville work and we can refocus our efforts, because it truly is a world-class asset that we have there. But it gives you a little bit of a sense of our portfolio -- 465 wells we're going to drill this year, as I'd

Back to Agenda

mentioned, 15 percent growth over last year and I anticipate with the Haynesville Shale land retention program that we'll be very efficient on adding reserves as well, and potentially new resources.

Joint venture activity -- you know, we've been active in the last three or four years in attracting a number of partnerships that accelerate our portfolio development. You know, there are assets within our continuing resource base that we won't get at for decades and, you know, every day we ask ourselves how we're going to move these things forward, how can we leverage the returns to make these things portfolio worthy. We've done well -- $2.4 billion attracted, $900 million invested to date, and we've added over 100 million a day, as that slide shows, relative to third party volumes, and I think this trend will continue. When I look at our portfolio across North America, we're really in this stage of trying to understand how the new technology can be applied across the entire North American framework, and with that, we're trying to understand how we sort plays out relative to supply cost and profitability. And that is a big sorting out project; it's not, let's do it right now, let's hypothesize. We do hypothesize, but we don't know until we actually apply, you know, horizontal 21 stage four million pound sand jobs across the tight gas and shale gas reservoirs within our current asset base, and also across the North American space. And we're doing that and a lot of the effort that we do when we do that, whether it's technology application around deep drilling or longer lateral horizontals or underbalanced drilling or whatever new technologies coming along, we leverage technology through joint venture operations. We try things and share risk as we try to sort out our portfolio of assets. So that's really the gist of what we're trying to accomplish in our joint venture activity.

Keys to unlocking shale gas -- you know, we've talked a lot about the recipe for success when you're developing new shale gas resources. There was a question earlier about have we optimized the Horn River at 21 stages or have we optimized any of the shale gas plays, and I think Randy alluded to it earlier, and I'd like to answer that question. The answer is no. The reality is, we're limited either by regulatory land issues, like in the Haynesville, where we only drill 4,000 foot horizontals in the Haynesville. We could drill longer. Or we're limited by the ability to execute with the current fit for purpose technology that we have. When you start pushing these four or five, six, seven, 8,000 foot

Back to Agenda

horizontals, you run into challenges around, you know, are you going to lose well bore integrity, are you actually going to be able to drill out the plugs, are you actually going to be able to place that casing. Those are issues that we're figuring out every day. Every day the service industry is bringing forward better tools. Everyday we're understanding how to do it better. There's no end in sight that I can see. It's going to continue and the pattern that you see today is going to continue. We don't see this decreasing value with increased stages. It's not like that, it's linear.

I'll flip through this pretty quickly, but, you know, the proof is in the pudding, and we've seen 15 to 20 percent reductions in our drill casing and tie-in costs throughout our resource plays.

And likewise, when we look at IPs, same thing. You know, we're seeing rapid improvements, particularly in gas shale plays where we're talking about increased fracture stimulation intensity in the operations that we conduct. So it just keeps going, and I don't think it's going to stop.

I wanted to comment about some of the fun things that occupy my time, regulatory environment, and the challenges that we face in executing our plan. First, responsible hydraulic fracturing, and it's been a topic of great discussion within the EPA and the federal government of the United States. Hydraulic fracturing is a safe and proven way to develop natural gas. In fact it's been used by our industry by over 60 years, and I should say it's been effectively regulated on a state and provincial basis for 60 years as well.

Encana meets, strives to exceed the strict requirements of hydraulic fracturing process, as set out by government regulatory agencies. All fluids that return to the surface are recycled or disposed of in regulatory agency approved disposal wells. Encana is continuously seeking ways to improve its technologies and operations from an environmental perspective. Initiatives underway across all of our operations help to ensure that Encana's managing the use of hydraulic fracturing fluids responsibly. The bottom line of that statement really is, we don't see it as an issue; we see this as being something that we have applied the most strict, stringent regulations for decades.

Back to Agenda

Water management. Water and sand are the primary components of fluids used in hydraulic fracturing. In addition, third party service providers, in consultation with producers, use highly dilutive volumes of chemical additives to ensure effective fracturing of the target reservoir and recovery fluids.

I want to make a point. There is no secret around the cocktails that fracture stimulation companies have. They will release it to anyone who needs to know but you have to understand that these people, these companies are in the business of trying to non-commoditize their product. They're trying to have a unique product, and they're going to market it to people like these gentlemen right here, with specific attributes that optimize reservoir recovery. But if you really need to know, they'll give you the recipe and I can tell you the recipe is not esoteric. There's nothing in the recipes that really should concern you.

In fact, the majority of fracture stimulation materials today is water, some surfactants and a small number of other type of additives but really we frac with water. It's a very benevolent operation. We try to use green fluids as much as we can. The industry's moving away from using diesel and fracture stimulation. And obviously, you could take a look at our reporting when we talk more about that in great detail.

So members of my leadership team are going to speak to you now in detail on identifying new opportunities. We're going to talk about finding shale plays. We're going to talk about gas factories. We're going to talk about a few of our emerging new commercial centres. But I wanted to leave you with a reminder of our recipe for success: strategic focus on technology development. It's critical that we continue to improve a culture of great people and assets and skills and experience and strong financial flexibility and capability. As discussed, we have a strategy for implementing this recipe and applications of reservoir characterization, drilling completion technologies and cost optimization, and we've already seen the success of that strategy and I think you'll see the continuation of that.

So without further ado, I'm going to pass the podium over to John Schopp and he's going to tell you a little bit about how to find this stuff.

Back to Agenda

New Ventures

JOHN SCHOPP (Vice-President, North Rockies and New Ventures, Encana Corporation): Thank you, Jeff. I'm Vice-President for the North Rockies business unit and U.S.A. New Ventures. The Jonah property, which is part of Wyoming I look after, we're not going to talk about today. If you want to learn about it, we've got an information package or you can ask me questions about it later.

I hope you're all enjoying the fabulous weather here. It feels funny to fly 1,000 miles north and have the warmest day I've had this year. This is great, Calgary hospitality here.

All right, I want to start out with the idea of seeing the possibilities. It's a very exciting time today to be involved new ventures at Encana, particularly given the shale gas revolution that's currently under way. Opportunities abound. Evaluation of these opportunities is highly technical; I'm going to share some of this with you today. It takes a company like Encana that is loaded with employees with over 20 years experience working in resource plays, tight gas plays, that can apply all this technology.

Our size and scale gives us fundamental advantages in this game. We are involved in most developing plays and the learnings from one play typically translates to another play and it's most important with shale gas because the evolution of technology is so rapid right now. In the next few slides, I'm going to show you our methodology to find and evaluate new plays and provide you with some examples in both Canada and the US of our track record of turning geological concepts into value for our shareholders.

So what's out there to find? Lots of things but, among other things, there's lots of shale gas to be found. The map here shows 28 shale basins in North America and there are at least 50 shales in these basins with sufficient organic content to make a gas play. But, you know, for a shale to have the right stuff, it typically needs to be in a relatively quiet marine environment with lots of life for organic content. These sediments have to be deeply buried so the organics can be converted into hydrocarbons and actually this is a relatively common scenario in North America so, again, how to separate to the best spots.

Back to Agenda

Play concepts have been evolving. In recent years, we learned that depth is not as limiting as we thought, with good porosity preservation deeper than we had expected. Natural gas liquids don't seem to reduce productivity as much as we thought either. Encana's land position is clearly well positioned to capture on these opportunities. Earlier, Randy highlighted our 12.7 million acres. It tends to often be well positioned. Of that, 2.3 million acres is on shale projects that we often talk about. Additionally, we have more shale exploration acreage, where we are working to prove these opportunities further before we bring them to your attention.

So how do we evaluate plays and know where to look? I won't go into all the details on the left side of this slide, but maybe I'll highlight on a few areas. It starts with identifying which prospects have the best chance of working. Basin histories and experience are combined with hands on rock work to really understand the rock fabric. The image that you see on the right is, it's called an x-ray tomography image. It's really a high tech CAT scan zoomed in incredibly tight of a tiny piece of shale from a drilling cutting; I thought most of you wouldn't have seen this before. In this image, the purple and pink coloured areas show space in the rock where organic matter has been converted into porosity and is now occupied by natural gas. The purple porosity shows connected gas that can flow out of the shale, while the pink porosity shows gas trapped that can't be produced.

Hopefully, this gives you an idea of how different shale technology is from tight gas technology. This entire shale image would fit inside one of the pores of a typical tight sand play, like our Jonah field; it's about 30 microns across. This is only one of many scientific tools we use to screen prospective basins and figure out which plays are likely to work. This particular image is from one of our stealth plays, which we have not yet mentioned externally.

The remaining evaluation steps – talk about them on the left – shows how we develop and translate our different ideas into expected economic scenarios. These scenarios are usually quite specific and variable across individual basins and help us maximize our chance of finding highly commercial opportunities in our exploration efforts.

Back to Agenda

So what makes a good play? There's a great many variables that need to be evaluated and small changes can have a big impact. On the left, we have below-ground factors; on the right, above-ground factors, which are both very important. In today's environment where the industry is resource rich, it is imperative that we accurately model the competitiveness of each play as it's developing. Having large resources is not enough; it's economic quality that matters and I know you understand that. Accurate representation of these factors early on is critical to our resource assessments and our new ventures process.

Details matter. We built this slide to give you a sense of that. The map on the lower left shows levelized supply cost variance across the Barnett shale for the remaining drilling in the play. We show the Barnett because it has so much well control so you can see with it a lot of resolution. The warm colours show the best areas where industry future drilling requires about a $3 gas price in order to generate a 9 percent return; whereas, the cool colours at the opposite end of the spectrum on this map require $6 to generate that 9 percent return. Just having Barnett acreage isn't good enough to compete. It's got to be in the right place in the sweet spots.

The bar graph on the right shows levelized supply cost ranges for our industry in both the lowest cost and the highest cost buckets in both the Haynesville play on the left and the Barnett on the right. Again, I think this indicates that it's more important to be in the right place than to be in the right play. Being in the right play helps too; it's a highly technical business. For Encana, this has always been of great importance.

This next slide is a cartoon to help maybe give you a sense of some of the drivers that cause downhole variability, particularly geological variability in a generic shale basin so you can see why things change so much. It's only one possible layout, but hopefully, it gives you a sense of this. Here we have a fairly deep hypothetical marine setting. On the left side of this image, you're too close to shore so river sediments are probably coming in and they're polluting the deposition material with a little bit more clay than we would like. The clay makes the rock a little bit tougher to frac as robustly, and it also hurts the permeability of the system. Also, the water doesn't contain as much life so there's lower organic content,

Back to Agenda

resulting in less permeability and porosity. This would still flow and it could still be a play; it just wouldn't be as competitive.

On the right side of this diagram, we have assumed that the rock has been buried quite a bit deeper than the stuff on the left and it's been over mature, or overcooked. The gas would contain too much nitrogen and CO2 and the permeability could have been significantly damaged by this cooking process as well. In the heart of the basin, in this case, is the best rock. Downhole variability can still be consistent within this area, though. We've got pressure increasing to the right and drill depth increasing to the right so drill costs are improving to the left and lower spots in the sea floor provide thicker deposition for more gas in place.

When we find a new play that we want to get into, how does Encana execute? We call our execution template our resource play methodology. Here is an example of how this methodology played out on the Haynesville shale. We started out with the land capture and exploration stage, kind of the top stage you see there. For the Haynesville, it required 340,000 acres and drilled eight vertical tests and one horizontal test from 2005 through 2007 as part of this stage. In the next stage, the pilot stage, we drilled five horizontal wells and acquired additional land.

The commercial demonstration stage commenced in 2008 as we worked to validate type curves and demonstrate targeted well costs. Commercial development is now under way as we ramp to over 20 operated rigs and we focus on lease retention. Play optimization will become full fledged when we go into gas factory operations as our normal operating when we're not working to retain land.

I want to now go through a couple of real quick examples. Here's a first mover advantage case on the Haynesville shale. For Encana, the Haynesville play started with us chasing the Bossier interval, with the Haynesville as a secondary objective. This map is a natural gas in place map of both the Haynesville and the Bossier. In our early land purchase, we bought that big patch of yellow that you see on the middle right of this map. This area was south of the Elm Grove Fault, where the Bossier becomes the most well developed. We bought the package with the thickest combined Haynesville and Bossier, plus we have excellent mineralogy by being far enough away from sediment sources to the northwest.

Back to Agenda

Finally, extra pressure south of the Elm Grove Fault provides an extra boost to both our gas in place and to our flow rates. And, of course, early mover advantage allowed us to capture the lands at an attractive price. The $2,500 an acre shown here represents our full cycle land cost to date on the play.

We have a similar story at the Horn River, which Kevin talked about earlier, in north eastern BC, where we acquired lands in 2003 before the play broke. The warm colours on this Horn River basin map highlight the thickest part of the natural gas in place. The polygons show Encana's acreage. Our lands are in the thickest part of the reservoir and those lands also have excellently simple structural complexity. This will make our horizontal drilling operations easier in the future. So, again, being early in the play allowed us to acquire prime acreage at a modest price compared to the industry Horn River acquisition price range. Again, it's about quality and we think we're in an excellent part of the play.

On this slide, it's kind of handy table that shows Encana's position on several emerging plays, some of which I think you know, you're quite familiar with. The second column highlights the year when we entered the play. You'll note that it's typically quite early in the game. Encana's land position on these plays total 2.3 million acres. When that's considered in relation to the natural gas in place in the fourth column, I think you can see that they represent a massive future opportunity.

What I wanted to leave you with on my last slide is to say that, of course, Encana's acreage position is much larger than the plays that we've been talking to you about so far today. Our 12.7 million net acreage is the result of years of selective acquisition and divestment. Hopefully, this discussion that I've made today will help you see how our early mover advantage has allowed us to capture prime acreage positioned for a value added resource. I think it's fair to say that Encana's a leader not only in land quantity but also in land quality.

Beyond these emerging plays, from the last slide and other discussions today, we are working on several new plays. We look forward to demonstrating commercially competitive success in the future. The opportunities include shale gas plays, plays with richer liquids content, plays that translate to our tight gas competencies. We have rig activity ongoing on some of these plays, and we have some exciting preliminary results and with continued success, we look forward to sharing these plays with you.

Back to Agenda

I think I'll pass it on now to Darrin Henke from South Rockies Business Unit.

Piceance

DARRIN HENKE (Vice-President, South Rockies Business Unit, Encana Corporation): Good morning. Okay, so John just showed us how Encana identifies and acquires new plays. I have the wonderful opportunity to show you in detail our gas factory in the Piceance basin.

As exhibited in this picture, one can truly see the beauty and majesty of the Piceance basin in western Colorado. Note that every picture in my presentation comes from Encana's North Parachute Ranch, where Encana owns both the surface and the minerals. At Encana, we uphold our constitution's principles on environmental stewardship and strive every day to minimize our impact on the landscapes where we operate.

All of the wildlife on this slide call North Parachute Ranch their home. With the principles of our constitution in mind, we initiated the gas factory process at North Parachute Ranch. What we'd learned along the way is that being good stewards of the environment often coincides with improved operational performance and an overall decrease in costs. Before delineating further on our Piceance gas factory story, I wish to first give a brief overview of Encana's performance in the Piceance basin.

On this slide, one can see Encana's land position in the Piceance exceeds 850,000 net acres and is distributed all throughout the basin. Over 70 percent of our lands are undeveloped and we have at least a 35-year drilling inventory at our current pace of development. To accelerate the value of our Piceance land position, Encana has closed numerous third party deals in the last few years. To date, Encana has given up less than five percent of its land position in return for $1.1 billion, which we are deploying at the drill bit, driving our internal rate of returns well above 100 percent. For every net Encana dollar deployed in 2009, we will receive over $3 in after-tax net present value discounted at 9 percent. From 2002 to 2008, we grew production at a compound annual growth rate of 32 percent and current gas production exceeds 450 million cubic feet equivalent per day. Note, we currently have six rigs operating in the basin.

Back to Agenda

Okay, back to the gas factory. Encana acquired the lease on North Parachute Ranch via the acquisition of Tom Brown in 2004. Less than one month later, Encana strategically acquired all of Unocal's assets in the Piceance basin, including the surface and mineral ownership at North Parachute Ranch, as well as some very significant water and pipeline rights. At the time of these acquisitions, North Parachute Ranch was completely undeveloped. Encana had a vision of how this property could be developed like no other in the Piceance basin. We had the vision of a gas factory. I need to be clear that when I reference the Piceance gas factory, I'm specifically referring to our activity on North Parachute Ranch. We have extensive ongoing operations elsewhere in the basin as well.

In this picture, it's evident we face significant topographical challenges in the Piceance basin. At North Parachute Ranch, we have several narrow valleys, where the valley floor can be as deep as 2,500 foot below the plateau. Our first goal was to minimize our environmental footprint. The best way to reach this objective is to fit as many wells as possible on a single pad and to locate as many of those pads in the valleys. Our next hurdle was to engineer how to safely implement simultaneous operations. By that, I mean conducting drilling, completion and production operations at the same time on the same pad.

One of our first gas factory endeavours was to design and build fit-for-purpose drilling rigs. Since our approach is to drill as many wells as possible from any given pad, we needed the capability to drill extended reach, S-shaped directional wells to greater depths than the typical Piceance rig was capable of drilling. As such, we designed these new rigs with bigger draw works and larger pumps to handle the increased demands. To safely conduct simultaneous operations, we turned the rigs 90 degrees and put heavy steel enforcement on the side of the rig exposed to completion and production operations. We added a hydraulic stopper system so the rig can walk from well to well and the addition of a top drive improves overall drilling performance and allows the drill pipe to remain in the derrick during mobilization between wells. A closed-loop mud system removes the need for a mud pit, thus reducing our footprint and environmental impact.

The illustrations on this page all pertain to a 4.2-acre pad, where we are actively drilling 52 wells. To date, 52 is the most wells we've been able to fit on one pad. I'm proud to say that over 500 acres at

Back to Agenda

reservoir depth will be fully developed via this one 4.2-acre pad. The picture in the upper right corner shows the challenge of installing buried gathering lines for each and every well. The lower right corner displays new wells being drilled on this pad, concurrent with 15 wells already completed and flowing on production. The image in the lower left is a cut-away showing the surface location along with the placement of the 52 wells in the subsurface. Note that our gas factory well pads possess no separation vessels or tanks, thus minimizing our impact on the view shed. In addition, no tanks mean we have no flash hydrocarbon vapours escaping into the atmosphere.

You likely are wondering what we do with our water and condensate produced from the wells if we have no separators or storage tanks on location. The answer is that we've built a central facility that we call the Middle Fork Facility. We collect all the fluids and gas that are produced from our wells into a three-phase gathering system that delivers the fluid via one pipeline to the central facility. I have additional slides that expand on the role of our Middle Fork Facility in the future.

Before we leave this illustration, I wish to point out that the small brown rectangles denote our well pads and the pink lines show the horizontal displacement from all our wells. You can see that many of our wells have horizontal displacements reaching three quarters of a mile under the plateaus. Our greatest horizontal displacement to date exceeds 4,700 feet. Remember that these are not horizontal wells but rather directional S-shaped wells, where we turn the wells back to vertical before we enter the reservoir targets. These long-reach S-shaped directional wells are just another area where Encana's redefining the industry's technical limits.

This picture, taken from a helicopter, overlooks our Middle Fork central facility. Again, you can see the incredible topographical relief and the deep valleys running through North Parachute Ranch. This facility truly is one of a kind for an onshore gas field. We have a very extensive pipeline network used for water supply, water distribution, three-phase gathering and gas lift. We have a large water storage pond and high pressure water distribution pumps that enable us to pump frac water to any pad in the field and thus recycle over 90 percent of our produced water. This totally eliminates trucking of frac water and reduces the number of frac tanks needed on any given pad for frac operations, good for both the

Back to Agenda

environment and for well costs. We also have the ability to gather and transport 360 million cubic feet per day via our 60,000 horsepower compressors.

This drawing further delineates the functions of the Middle Fork central facility. The inflows to Middle Fork, shown with the arrows pointing toward the red box, include the three phases of fluid flowing from the well pads, natural gas, produced water and condensate. And the other inflow to Middle Fork is the makeup water for fracturing that we pump from other operations in the basin or from the Colorado River, as needed. The outflows from Middle Fork, shown with the arrows pointing away from the red box, include frac water, water disposal, gas lift gas, condensate and gas sales. Outside of condensate sales, all of the inflows and outflows to the Middle Fork Facility use the pipeline network. Having gas lift gas available to our well pads is instrumental in maximizing production from the wells. The gas lift gas enables the removal of water from the wells so that the wells produce more consistently and ultimately recover more reserves in their lifetime.

The bar charts on this slide exhibit the continuous improvement we have observed in our well results in North Parachute Ranch. While some improvement likely would have happened without the gas factory methodology, the following examples are results clearly tied to our gas factory. With respect to initial productivity, our water distribution system enables us to easily modify, both operationally and financially, the size of our frac stages and we clearly see better initial productivity with larger volume stages. Another learning from the gas factory is that when we park a drilling rig on one pad and drill a multitude of wells, the crews are able to resolve the fine geologic nuances associated with that immediate area, and as a result, they drive their cycle time down. Since 2005, we have reduced our drilling cycle time by 65 percent, dramatically improving well costs.

In both these pictures, Encana is conducting simultaneous drilling and fracturing operations on North Parachute Ranch. I'm proud to say that in just a few short years, the Piceance gas factory has progressed from the conceptual stage to full implementation, with over 500 wells producing in excess of 200 million net cubic feet per day. Encana has nearly 100,000 acres of contiguous undeveloped leasehold

Back to Agenda

adjacent to North Parachute Ranch for which we plan to expand our Piceance gas factory, and we are also expanding this concept to many places outside the Piceance as well.

In conclusion, with all the environmental challenges and water consumption issues associated with our industry, those companies that minimize their footprint, reduce their emissions, recycle their produced water and minimize the use of fresh water, those companies will have a distinct advantage in the marketplace. Encana clearly is an industry leader on both the gas factory methodology and the implementation.

Okay, well I'm going to turn it over to Danny Dickerson from the Mid-Continent Business Unit and he's going to discuss the Haynesville shale in East Texas.

Haynesville Shale & East Texas

DANNY DICKERSON (Team Lead, East Texas and North Texas, Encana Corporation): Good morning. Thank you, Darrin. I'd like to discuss two things with you today. I'll start off by providing an overview of Encana's Haynesville Mid Bossier shale play and the exciting opportunity there. I'll then follow up with a quick review of our East Texas growth opportunities.

The Haynesville may be the hottest play in North America today. In January this year, more than 150 rigs were drilling in the play. Encana continues to be encouraged by our well results with maximum 24-hour IPs increasing to greater than 20 million a day, as noted by the green circles on this natural gas in place map. Encana's lease position is strong with much of it lying in the heart of the play. We're currently focusing our development on the northern portion of our joint venture with Shell in the Red River and Desoto parishes of North Louisiana. Although there's a lot to learn, this play is becoming a leading resource for Encana. We expect our net production this year to average 325 million a day.

The Haynesville has massive NGIP, with contingent resources for Encana in excess of 8 Tcf recoverable on a 2P, 2C basis. With the ongoing execution improvements, we expect it to quickly move to the top of our portfolio. For 2010 and 2011, we are executing a program to ensure that we retain our most prospective land; that's our land retention strategy. We currently operate 23 rigs and expect to average

Back to Agenda

between 20 and 25 rigs for the year. Our partner, Shell, will have seven to 10 operated rigs. We're also initiating an in-fuel pilot to determine the optimal well density and development methodologies; this is the gas factory that you've heard about today. We feel that this play will be one of the growth drivers for Encana over the next several years.

This plot shows Encana wells that have IP'd in the last 90 days, shown in the bold colours. Initial rates are very strong, with most recent wells beginning at or above 20 million a day. Improvements in completion techniques, such as adding more frac stages, refining our perforation clusters and increasing the proppant concentration per stage have uplifted the flow capacities greatly. Initial wells were limited by the treating capacity and, hence, the flat period in our type curve. Encana has supported third party gathering and treating systems in North Louisiana, such that the wells are now able to flow unconstrained at rates greater than 25 million a day and pressures of 7,000 pounds plus per day. Although it is early days in this play, in the core area, the performance of our recent wells looks promising relative to our expected 7.5 Bcf type curve.

With the Haynesville, as with most shale plays, the simple story for well completions is that longer laterals with more stages make better wells. We're moving forward from about 10 stages per well to 12 to 16 stages. As shown on the previous slide, we have pumped a 20-stage test which IP'd at over 35 million a day. We're also increasing our proppant concentration from about 1,100 pounds per foot of lateral to about 1,500 pounds per foot of lateral. This will increase the stimulated rock volume and maintain facture conductivity over the full well bore life. Overall, these completions improvements have raised the EURs from our initial 5 Bcf to the current 7.5 Bcf per well. I will point out, as Jeff mentioned, that we are investigating the regulatory requirements to enable the drilling of longer laterals; that is likely two years out.

As illustrated by these two bar graphs, operated well performance and costs are both improving dramatically. The graph on the right shows the average production for the first 30 days of a well life. We call this the 30-day IP. We use IP 30 versus spot rates as we feel this metric provides a better early indication of the long-term well performance. We expect Encana's 30-day rates to advance nearly to the

Back to Agenda

20 million a day range currently reported in 24-hour spot rates. At 17 million a day, a well produces over one half a Bcf of gas in just the first month. Recall from the previous slide that we've tested wells at greater than 30 million a day and that the infrastructure is becoming more readily available. Costs also remain a huge component of the play and are one of our principle focuses for 2010. Our average well costs had been reduced greater than 40 percent in a little over a year. The best three wells in this play to date were drilled, completed and tied in for less than $7.5 million.

A key for this cost reduction has been drilling efficiencies, which has been improving impressively. Our spud to rig release times are moving towards less than 40 days and currently about 35 percent of our wells are in the low 40-day range. A driver for these improvements and faster drill times has been primarily bit and motor optimization. We've also reduced our cycle time by two to three days via rig move efficiencies and by presetting surface casing with a spud or rig. Our goal is a more consistent 35 days per well by the end of the year. Our fastest well to date has been 29 days, indicating that this 35-day target is very achievable.

The next step in our cost evolution will occur as our development shifts out of the land retention phase, where we're drilling one well for every 640-acre section to our multi-well pad drilling at at least eight wells per 640-acre section. Again, we've coined the term gas factory to describe the efficiencies and improvements that pad drilling has achieved elsewhere in our portfolio. Darrin showed you the improvements that we were able to achieve in the Piceance; we're going to take those learnings and quickly implement them in the Haynesville. You can see the drawing of a gas factory here. We generally build the pads on a section line and drill both to the north and to the south so this gas factory shows just the north drilling. I'll ask you to imagine a similar factory oriented to the south.

As we move to drilling the multi-well pads, our costs are estimated to immediately drop to below $8 million. A key initiative for the gas factory drilling in 2010 will be to test this cost reduction concept and to get early reservoir data on the ultimate spacing for the Haynesville. Currently, this is 80-acre spacing; we want to test in some areas if we can go to 40-acre spacing. We plan to begin the gas factory drilling in the second quarter of this year.

Back to Agenda

It's clear that Encana is well positioned in the core of the Haynesville. The commercial development plan that we currently have centres around about 200,000 net acres in the heart of the play. We are also well positioned in the emerging Mid Bossier shale too as this NGIP map illustrates. The early results from the Mid Bossier are posted on the map and are quite encouraging. We recently completed two wells, the Brown and Walker, each flowing over 20 million a day. From a rock quality perspective, the Mid Bossier exhibits the potential to be as strong a producer as the Haynesville. We feel the rock here is as good as the Haynesville has proven to be. Our early estimates are 6 Tcf in the Mid Bossier. This plot shows why we're optimistic about the emerging Mid Bossier shale. Encana's latest two wells, again, each tested over 20 million a day. The early decline data is very similar to the Haynesville and indicates an EUR range of 5 to 7.5 Bcf.

This map highlights the area in which the Haynesville and the Mid Bossier natural gas in place exceeds 100 Bcf in each zone. The shading, therefore, defines the overlapping core of both the Haynesville and the Mid Bossier. It illustrates that the majority of our acreage contains significant natural gas in both zones, up to 400 Bcf per section. Imagine the economics of going to a single section and drilling both a Haynesville and a Mid Bossier gas factory. These vertically stacked gas factories will double the number of wells per section, double the production volumes per section, all while utilizing essentially the same surface infrastructure. Imagine the economics.

The Haynesville and Mid Bossier resource estimates continue to grow for Encana. Last year, we added approximately 700 Bcf of total prove reserves and currently have a 3P of 2.9 Tcf. We have a very conservative contingent resource estimate of 13.5 Tcf on Encana lands. We'll drill several step-out tests to expand the proven core of both the Haynesville and Mid Bossier plays and increase these resources further. The above 13.5 Tcf lies on about 230,000 of our total 429,000 net acres.

A core value for Encana is responsible development. As such, we're developing and implementing a comprehensive environmental management system for the Haynesville area to address all potential concerns. Although it's not an issue at this time, we want to ensure strong management of water resources. We currently use primarily surface water for our frac operations, and we are exploring water

Back to Agenda

recycling. As we'll show you this afternoon, Encana wants to encourage the use of the product that we produce, clean burning natural gas. As such, we'll be incorporating natural gas into our rigs fleet this year. Likewise, we're building an Encana CNG fuelling station for use by our operations vehicles in North Louisiana. From a reputational perspective, we want the communities and land owners to view Encana as the operator of choice.

In summary, we'll focus on three key items for the Haynesville and the Mid Bossier shales. First, we're going to focus on land retention with about 90 percent of our program focused there. Second, we'll pilot gas factory infill development and further drive our capital efficiencies to push our well costs below $8 million. Third, we'll be doing some extension step-out drilling to prove up additional Encana acreage. We'll be testing both the southern portion of our JV acreage, which is in Desoto Red River parishes, and we'll also test portions of East Texas in Shelby, Sabine, and San Augustine counties. So you can see that the Haynesville's on track for stellar production growth as we develop the 1,600 well inventory currently identified. Now, let me change topics quickly and give you a brief preview of our East Texas opportunities.

The East Texas Deep Bossier has been the growth engine for Encana over the past few years. 2009, in fact, was our best year ever, with the play reaching record production in early 2010. A key win for 2009 was expanding Amoruso eastward. The eastward area, shown in the light red here, grew from about 40 million a day to over 225 million a day gross production currently. This year, Encana is aggressively seeking opportunities to expand East Texas, both in the Amoruso area shown on this map and along the entire Bossier Jurassic trend.

I really enjoy presenting this slide because it shows how the Deep Bossier wells stack up from an initial production standpoint when you compare to other industry wells, looking at the highest three-month production average. Note that nearly 50 percent of the wells on this list are Deep Bossier wells drilled by Encana. Now you may have seen this graph before in other presentations but also note that we continued to complete impressive wells in 2009. In fact, seven of the 23 wells on this plot were drilled

Back to Agenda

last year and I expect to add to this list in 2010. Because the play provides top quartile metrics, we want to expand the Deep Bossier along trend. We're attempting to replicate this success elsewhere.

The Deep Bossier Jurassic trend, as shown on this map, extends from East Texas through the Gulf coast and into Florida. Encana has a robust prospect inventory along the entire trend, with about one million net acres of leasehold. We have nine prospects in various stages of development from initial lease capture to drilling, and we expect to drill two to four of these prospects in 2010. In short, we're looking for the next Amoruso.

So to summarize my discussion today, the Haynesville is an excellent play for Encana that is currently exceeding our expectations. We expect it to lead Encana's production and reserve growth over the next several years. The Mid Bossier is an emerging shale play with encouraging initial results. East Texas continues to provide high impact production with, likewise, several growth opportunities in progress.

I'd like to thank you for your attention. I believe it's now time for the US Division Q&A.

USA Divisions Q&A

BILL OLIVER: All right. We have the same format here so if you've got a question, please raise your hand and we'll have a microphone come to you. Question?

UNIDENTIFIED SPEAKER: With regards to East Texas, I was wondering if you could expand on the opportunities there? I know one or two years ago it was categorized with the Montney Horn River and the Haynesville as a 1 Bcf a day producer. That seems to have been pushed back and it's not so much a high growth… it has been put more in the moderate growth bucket so could you maybe explain what's happening in East Texas and how that growth has been impacted, I guess, over the last year and a half?

JEFF WOJAHN: Sure. You know, I mentioned in my presentation, I like the area from a geological resource point of view, probably better than any other area. I think the biggest thing that happened to us was when we talked about those higher growth rates initially, we really talked about a more aggressive delineation program in the greater area. Our lands are held by production and so we don't have a need to do that work. The majority of that work, I would call it in the potential resource category, not contingent or proved resource categories. We have resources in place with greater than 500 Bcf per section in the greater East Texas area so what we've done in the last three years to grow our production is focus in close around Amoruso development. We've done a little bit of work in the East Amoruso, and as Danny said, we're moving a little bit to the north. We haven't done any tight gas development; we haven't done any shale gas development.

But I may point out to you that a lot of the characteristics that led us down the path of moving into the Haynesville and the Mid Bossier started in East Texas. Those opportunities still exist there and, at some point, we'll get there. But when you look at our budget overall, you see that, you know, we're infatuated with the land retention strategy in the Haynesville and that, by and large, has been the majority of our initiatives to date. But I anticipate that, as we get more comfortable drilling longer, deeper horizontals, you know, in the components of the Haynesville and move past our land retention, we'll resume talking about higher growth in East Texas. That, ultimately, will complement what we're doing in the Haynesville. So I very much see East Texas as… we categorize it as moderate relative to the IQRE evaluation, but as we move forward with our technology development, I very much see it as a high growth opportunity in our portfolio.

DANNY DICKERSON: I think the other key there is that, as we're focusing on our Haynesville ramp up in our office, we moved some of the rigs from East Texas and we want to make sure that, operationally, we execute the Haynesville ramp up to the best of our ability, so we moved some of our rigs and that type of thing over to the Haynesville.

UNIDENTIFIED SPEAKER: We can only do so much.

BILL OLIVER: Any other questions?

UNIDENTIFIED SPEAKER: You've got a little box here of Marcellus. I wonder if you could just talk about that and your US map?

JEFF WOJAHN: Sure. We've followed the Marcellus play for well over five years, and we've debated internally on whether it's a play that competes with, you know, the Horn Rivers or the

Back to Agenda

Haynesvilles or those kind of plays in our portfolio. And there's some certain aspects about the Marcellus we really like. We like the gas content, the liquids rich content, the uplift associated with liquids. We like the proximity to market. We like the netbacks coming out of the region and it has been the attractive component of the play.

What we don't like is the regulatory environment and the issues around fracture stimulation and water regulations. And so we've kind of made the decision that we would take a look at it and explore the above-ground issues in greater detail, and so we announced that we had acquired a small position, a toehold position in the Whitmore. Right now, we're going through the process of drilling a few wells and getting a taste for what the real issues are.

Another issue was, you know, are we too late in the play, do we need to spend too much dollars to get into the play? And, you know, as John talked about with shale plays, you either get in early and buy a million acres in the Marcellus, or something like that, or you make damn sure. And we're more in that making sure phase if we were ever going to make the Marcellus compete within our portfolio. So I think, you know, one of the things when you look at the play, there's a fragmented land base, there's difficulty in contiguous operations. It's by and large been dominated by, early in its phase by smaller players. There's bigger players when we need the play; obviously, Chesapeake's a big player and others, Range Resources.

But, you know, I think if we were sure that it was going to compete within our portfolio, we could step forward and get a bigger position and, clearly, the Dominion announcement this week, when you break that down on a dollars per acre basis, is pretty reasonable and so there still is remaining opportunity in the Marcellus. It's a massive land play but, you know, when we've looked at it and how it competes relative to the Horn River or the Haynesville and Mid Bossier, we've chosen to go in a different direction. But that's not to say that we couldn't change it in the future.

BILL OLIVER: Any other questions?

UNIDENTIFIED SPEAKER: Hi, Jeff. You've been drilling lots in the US and I'm just wondering if serendipity has helped you out. Have you been finding any oil plays on your US lands?

Back to Agenda

JEFF WOJAHN: You know, obviously in the last three to six months, there's been a fair amount of discussion about liquids uplift. You know, when you look at a play like the Montney, it has liquids uplift and, you know, obviously we're significant players in North Texas and the Barnett and the liquids window as well, and we're not allergic to NGLs or condensate. I want to make that clear. We understand the netback improvement, you know, in these plays that it… whether it's the Marcellus or the Eagleford or the Montney and other plays and it's just one component that we look at when we look at how these plays compete in the supply cost basin.

So, you know, when John talks about profitability and how we can support lower supply costs in our portfolio liquids content, is one of the boosters. Of course, there's other boosters as well, like over-pressured shales or contiguous positions in the Haynesville or Horn River that those aspects need to compete with but, you know, clearly we haven't really talked about liquids as being a key contributor to our netbacks played. It is embedded, to some extent, in our portfolio and I think we have optionality around our land base and a lot of our contingent and potential resources to pursue that strategy more fulsomely if we chose to. We have exposure to it.

BILL OLIVER: All right. With that, gentlemen, I think we'll move on with the program. Thank you.

Our last speaker this morning is Eric Marsh. He's our Executive Vice-President of the Natural Gas Economy, and he'll be speaking to us about the initiatives we've got underway to expand the demand for natural gas. We have a handout; you see the memory stick. On it contains a video that was created internally by Eric's team and our communications team and it's a young lady who dreams of a world of natural gas so it's all part of our education we're trying to have with many of our stakeholders to look at the value of using more natural gas, both as a transportation fuel and for more power generation. So if you've got an opportunity, I think you might find it of real interest.

So, Eric, with that, we'll turn the platform over to you.

Back to Agenda

Natural Gas Economy

ERIC MARSH (Executive Vice-President, Natural Gas Economy, Encana Corporation): Well thank you, Bill, and good morning, almost good afternoon. I want to thank you all for coming to our investor day presentations today. I know it takes a lot of time out of your schedule and very much appreciate it. I would like to talk to you about some of the initiatives we have going in the natural gas economy. I'm Eric Marsh, Executive Vice-President of the Natural Gas Economy here at Encana.

Some 14 months ago, under Randy's guidance, we created a highly technical team under Wayne Geis and David Hill to analyze opportunities and to advocate for the use of natural gas.

Our mission is to establish natural gas as the foundation of America's energy portfolio. As you've heard from others, we believe that natural gas will be abundant and affordable for the future. Natural gas has great environmental attributes and it's been reliable for over 100 years; matter of fact, in 1910, the United States was producing about 750 million a day so over 100 years we've been producing natural gas and it's been very reliable.

Because it's produced right here in North America, some 3.4 million people enjoy the benefits of working in our industry.

We have a vision that has natural gas enabling the energy future that includes natural gas as a preferred fuel for power generation, and natural gas for providing fuel for vehicle transportation. Adopting the increase of natural gas in these two sectors is what I'll be discussing today and what will require the efforts of all of our stakeholders. Our modeling would suggest that for every 1 Bcf a day of incremental gas, it requires 30 to 50,000 jobs to develop that gas. Success will create jobs, profitability, reduced emissions and increased government revenues. That's what we call the natural gas economy.

As you've heard from the team's presentations today, the industry is having great success in unlocking vast new supplies of natural gas from shales and other unconventional sources at lower and lower costs. The total resource estimate now stands at over 100 years supply at current production rates but these estimates, they're increasing every day. Just like what the guys showed you today, every month goes by, we learn more about the plays and those resource estimates continue to go up. We believe that, in

Back to Agenda

the United States and Canada, production can be increased to upwards of 100 Bcf a day and that's in a fairly reasonable period of time. This is an increase of 25 Bcf a day, or approximately 30 percent, so we believe that one of our greatest challenges is really around the focus on how do we use that 25 Bcf a day that we believe that the industry will bring forward.

The abundance has made natural gas affordable. This is a graph of the price comparison of natural gas, oil and coal on an MMBTU basis. Natural gas is being sold at a price similar to 2003. What is interesting to see on the graph is in mid-2004, natural gas and oil prices begin to separate. Since then, natural gas sells at less than 50 percent of that of the price of oil. The abundant supplies of natural gas are also expected to make the price more stable in the future.

When we compare natural gas and coal, we need to recognize that coal is primarily used for generating electricity. Natural gas power plants can have more than 60 percent greater efficiency than coal-fired power plants. For every BTU of natural gas, you need 1.6 BTU of coal so when you look at effective coal price, this is what you have. So for the first time, natural gas and coal are competitive on a price basis. In many areas of the United States, natural gas is actually cheaper than coal and when you look at the environmental benefits, natural gas is clearly the winner.

When we look at the total costs of new power generation, natural gas is the lowest cost electricity producer. This is primarily driven by the fact that natural gas combined cycle plants are less expensive to build than other energy type plants. So with natural gas being the most affordable, let's look at the opportunity to reduce emissions and improve the environment.

When we review the energy consumption in the United States and Canada, three sectors consume 88 percent of our energy: industrial, transportation and electricity generation. Natural gas can be used in all three but transportation and electricity generation are our largest opportunities. Seventy-nine Bcf a day and 110 Bcf a day is the opportunity available to use natural gas in these markets, so quite a large opportunity. As for the emission reduction and the opportunity to improve air quality, these two sectors represent 70 percent of the air emissions generated in the United States and Canada.

Back to Agenda

This is a combined emissions target for the United States and Canada. The goal will be to reduce the emissions by 17 percent or 1.3 billion metric tonnes by 2020 and then even more beyond that out into 2050.

The plan requires each sector to reduce the emissions by 17 percent in the way it's laid out. The reality of the situation is that the industrial and residential sector will be extremely challenged to reduce their sector's emissions. The transportation sector will be challenged to increase the number of electric and natural gas vehicles at a rate than can have an impact on emissions within the next 10 years and so the majority of the emission reduction will fall into the electrical sector, with the transportation sector being a bit slower to respond.

So if we go back to our 25 Bcf of incremental gas and put 15 Bcf a day to the power sector, 10 Bcf to the transportation sector, as in the second line of this graph, we clearly meet our targets and we leave a little room to grow the emissions in the industrial sector. So this is good for business and it's good for the environment.

So when we discuss reducing emissions, often we're asked, "so at what price?" This brings us to really the most significant question: How do we balance doing what's right for the environment and doing what's right economically? So let's look at finding the right balance. The majority of the emissions come from the electrical sector so we'll take a look at it first.

Today, the US and Canada produces 4,500 terawatt hours coming from 42 percent coal, 21 percent natural gas, 20 percent nuclear and 17 percent hydro, wind and solar, all lumped in to what I'll call the renewable category. We generate 2.3 billion metric tonnes from the electrical sector and our collective power cost is approximately $0.09 a kilowatt hour. Many states and provinces have set an RES standard, renewable electricity standard, to be between 10 and 20 percent. This is set by legislation and so electricity cost on consumers is going to go up because of that. So if we advance our clock to 2020 and increase renewables to 25 percent at the expense of natural gas, emissions increase materially and your electricity costs of about $0.09 a kilowatt hour goes up by 10 percent to $0.10 a kilowatt hour and this is primarily due to wind and solar being more expensive. Now, if we allow natural gas power generation to

Back to Agenda

increase from 21 percent in the first line to 34 percent at the expense of coal - otherwise natural gas, you know, cuts into coal - we lower our emissions by 30 percent and we have the same cost as we had previously.

So from a societal perspective, this points to the right balance. The 2020 mix with growth in renewable and natural gas reflects an additional 15 Bcf a day of natural gas in the power generation sector, which we assume is consumed in high efficiency advanced combined cycle plants. This is an example of what may be considered the best future energy mix for all of the United States and Canada.

Let me now just make a brief comment or two concerning how certain jurisdictions are actually starting to catch on to the new virtues of natural gas and replacing coal in the electrical power generation. A few weeks ago in the State of Colorado, the State of Colorado announced an energy plan in which a coalition of gas and industry partners, environmental groups and government regulators will work with Xcel, the largest utility, to retire and to retrofit up to 1,200 megawatts of coal-powered fire generation. This single piece of legislation will allow for 160 to 180 million cubic feet of gas per day of additional gas consumption in a state which has typically had 65 percent of its power generated from coal.

In February, Saskatchewan Power Corporation and Northern Power Income Fund announced the building of a 260-megawatt natural gas plant that will consume about 30 million cubic feet per day of clean burning natural gas, so another great win for the natural gas industry in a province that currently generates 60 percent of its electricity from coal. Two strong examples of how recent industry advocacy and awareness of economic and environmental benefits of natural gas are changing the power generation landscape.

But before we leave the electrical emissions sector, natural gas can significantly reduce the harmful emissions in the air, sulfur dioxide and nitrous oxide, which are very harmful and are likely more closely to be regulated in the next few years. You hear a lot from the EPA that these will be two targeted chemicals that they will continue to really regulate and look at new ways to reduce over the next few years. Our two cases that we just looked at apply 15 Bcf a day of additional natural gas to power generation and it lowers the nitrous oxide by 38 percent, and sulphur dioxide by 52 percent. These

Back to Agenda

hazardous emissions from the coal-fire power generation have been estimated to cost the United States $62 billion annually due to respiratory illnesses and premature mortality. This equates to over $0.03 a kilowatt hour that needs to be added on to the coal-fired electricity price to consider the total cost comparison. So natural gas improves air quality and that translates to better health for society.

Well, moving on to transportation, there are 10.5 million vehicles running on natural gas in the world; only 125,000 here in the United States and Canada. We think this represents a great opportunity. We've studied other countries like Italy, and we find that there's a great opportunity to expand the market for natural gas in a similar fashion. Nearly 7 percent of the market in Italy is running on natural gas. What made it happen is a large spread between natural gas and gasoline and a very stringent tailpipe emissions standard that sets taxation on the amount of emissions for each vehicle type. We think these type of tailpipe standards make a lot of sense and would propose that they include tougher sulphur dioxide and nitrous oxide levels.

CNG is typically 20 to 40 percent cheaper than diesel and/or gasoline. Fuel is typically the largest operating cost in the trucking industry and we believe that we can reduce that and create fuel price stability. You can also see that the largest component of selling natural gas for fuel is the transportation and distribution via the regulated entities. One of our largest challenges is to work with the utilities to ensure the price differential; the price differential is key to our success.

The market opportunity in the transportation sector is 79 Bcf a day. The biggest opportunity is the 230 million light duty vehicles, cars and pickup trucks, but the most likely place to start is the freight trucks and the commercial vehicles. This is a 16 Bcf a day opportunity that has the largest emissions profile. One 18-wheeler creates the emissions of between 150 and 300 light duty vehicles. By focusing on the trucking sector, we can make an immediate impact on emissions with less capital.

We have proposed to the Canadian federal government and most of the provincial governments that we partner with industry and government to create two natural gas corridors, one in Eastern Canada, one in Western Canada. We have discussed the concept with many businesses, and we believe that focusing on fleets, trucking, buses and garbage trucks that the infrastructure can be built for commercial

Back to Agenda

use and then expanded to light duty later on. With success, the light duty will begin to produce more dedicated natural gas vehicles and give the consumers more choices.

This is an example of our modeling projected out to 2025 that we presented to the Canadian federal government. It assumes some incentives for the trucking industry and for infrastructure. These two corridors would use about 1.4 Bcf a day of natural gas in 2025 and, by 2035, over 2 Bcf a day so another great opportunity to use natural gas. This captures 18 percent of the trucks that are driven in Canada by 2025 and only captures 10 percent of the light duty vehicles, so still a lot of opportunity in the light duty vehicles as we go forward.

This is what we're doing at Encana. We've begun many of these projects and hope to have many of them complete in 2010. So you can see that we're looking at building natural gas stations for our own Company vehicles. We'd like, over a period of three to four years, to get all of our vehicles, or the majority of the vehicles running on natural gas. We're also looking very much and working with many of the major cities that we live in and around to create some clean cities programs, where we'd use natural gas for fleet vehicles, perhaps at the airports, taxis and garbage trucks, as I had mentioned. So at Encana, we're not only, you know, thinking about it, but we're actually getting quite a bit done in the form of using natural gas.

So we do have some challenges. Regulatory barriers do exist. We will need to modify some of them to make our product even more competitive. As we look at this, this opportunity has many great attributes. With this abundant, affordable, clean product, we believe we are just at the beginning of something great.

Thank you and I'll turn it back over to Bill and… for some questions and answers.

Panel Q&A

BILL OLIVER: Thank you, Eric. So, Sherri, Randy, Eric and Renee are going to come up and we're going to have our final panel for Q&A. All right, questions.

BILL OLIVER: We have two questions over here. Thanks, Ryder.

Back to Agenda

UNIDENTIFIED SPEAKER: Thank you. Question for Randy. You mentioned, I think, in your comments that one of the metrics you are using for employee compensation is the recycle ratio netback relative to three-year finding and development costs and I wanted to see if you could contrast the benefits of that versus your growth production, or your production growth trajectory; in other words, is there not a potential to get a higher netback from higher natural gas prices and potentially lower F&D costs if there's not cost inflation. If you were to grow at say a slightly lower rate than 15 percent on an annual basis versus continuing to grow at the 15 percent rate given, I think, in the charts, one of your macro charts – and I might be eyeballing it – Encana may be contributing 25 percent of the total North American production growth in the next few years?

RANDY ERESMAN: We've used the recycle ratio for our long-term compensation for the last number of years, and we feel it's a great measure because what it does is it engages all of our employees throughout the entire Company because it, you know, what's involved in it is, of course, a netback which is derived from the price that we receive and we include our hedging in that price, the wins and the losses. It keeps us… It keeps our operating costs, you know, so our operations focused on operating costs and on G&A so all those components are deductions out of netback. And then, of course, it engages those people that are involved in the capital programs to make sure that they are also optimizing capital to create the lowest finding and development cost.

We've set the target pretty high, at 2.5 times and that's the midpoint of our target range. We actually get our highest compensation if we can reach the 3.5 times. So we are actually very aligned with the shareholder on trying to… why we're trying to maximize growth rate and we think growth rate is going to be extremely important as well because, if we're going to do that and also have a good finding and… recycle ratio in the process, we are obviously creating maximum value for the shareholder. If we start seeing pressure on the numbers, as Jeff and Mike have probably said – well, I heard Jeff say it for sure – you know, because of things changing in a specific area, we have enough other resource opportunities to go to to back off in that area.

Back to Agenda

We do not want to be the company that causes industry inflation, but we fully recognize that… Eric has a big challenge in front of him to grow the market and so our greatest value proposition for the shareholders is get recognition for that huge inventory that we have. You know, when you look at our 3P plus 3C case, you know, it's an inventory that's 50 years long and that's too long to have in our portfolio, recognizing we're probably still going to continue to grow it over time. So we want to find as many ways as we can through accelerating our existing portfolio with our own capital and then also to try to do more deals to take some of that portfolio that maybe isn't of the highest quality but if we can also accelerate that at the same time, that's the best proposition for value generation for our shareholders. And I hope the rate's going to be higher than that, doubling in five years and, you know, we can see a line of sight where that is a potential as well, but I'm not promising that today.

BILL OLIVER: I think there was… Ryder, there's another one at the front.

UNIDENTIFIED SPEAKER: Randy, this is probably for you as well. If, to quote Jeff, land retention wasn't such an infatuation, how would your various resource plays rank in terms of priority, either for economic merit or capital allocation?

RANDY ERESMAN: Well, each of the resource plays has, you know, a sweet spot in it and then once you get beyond the sweet spot is really what we have to think about for the incremental capital spending. We try to always maximize the spending in each of the plays. And then what we would do is we look at the incremental economics of sort of the next level of activity in each of the plays. And then we also look at, you know, where we are with respect to infrastructure. In a play like Mike McAllister's Montney play, it has today some of the very lowest supply costs in our portfolio. You know, it's in that $3 range. So we would like put more money there. That'd be obvious. But the issue there is that we're pushing infrastructure all the time so as he grows to his Bcf a day target, he's going to have to keep on building infrastructure and that's going to constrain, to some degree, the pace of his development.

Same situation goes with the Horn River. The Horn River, where we don't have the land retention issue, Kevin Smith has the opportunity to hold great quantities of land with very few wells. There's great land tenure in British Columbia so he's automatically able to go to gas factory development and start

Back to Agenda

testing how far down in terms of costs, cost structures we can get that play to. And we'd like to give him more money but he's, again, limited by the early stage of that play. We don't have all the answers yet. And it also has to push infrastructure locally. Now, in Western Canada, we have tons of additional capacity, 3 Bcf a day of free space on the pipeline so we can grow a long time before we have to worry about a long pipeline connection and that's a great thing for Western Canada.

Some of the things that make the plays in Western Canada now somewhat more competitive than they were historically with the US plays are because of that extra free space on the pipeline, which has lowered our tariff and dropped down our basis differentials. But also because of the royalty structures that were implemented in British Columbia that go a long way, you know, two percent until payout and then – what is it, 14 percent until two times payout and then a reasonable royalty rate after that – that goes a long way to make up for the extra productivity relationship that we get out of plays and lower costs because of the location of the plays in Louisiana and Texas.

If we weren't also doing so much work on retaining the Haynesville… The Haynesville, as Jeff and Danny pointed out, is a place where we have our Mid Bossier sitting right on top of the Haynesville but we're required to go down into the Haynesville in order to retain all of the land above it. And so if we weren't as busy on the Haynesville today, we'd probably be really delineating more of the Mid Bossier today as well. But, again, as we've all pointed out, locally there's a constraint. I mean the production growth has been quite amazing. I think… Is it about 3 Bcf a day coming out of the Haynesville now?

UNIDENTIFIED SPEAKER: Two and a half.

UNIDENTIFIED SPEAKER: It's two and a half.

RANDY ERESMAN: Two and a half and building by year end maybe 3.5, 4, something like that. So there's local infrastructure that's got to be developed in that play so that is constraining that area. Now, we've got… the Rockies area has been also a benefactor of the major pipelines that have gone… the Rockies and the Ruby pipeline that have increased capacity in that area and that's allowing us to develop Jonah more aggressively today, putting in more wells there. And we're also starting to think about doing more of the pad well work in the Piceance basin.

Back to Agenda

So, we start off with trying to optimize… and, you know, put all our money into the lowest cost plays but then the reality is there are always a number of constraints. But we do have definitely the capability to pick up our pace of development, certainly by 25 percent as an average across our portfolio.

BILL OLIVER: Any further questions?

UNIDENTIFIED SPEAKER: Can you give us a bit of an overview on what legislation or bills that are at the US that are helping with the… to incentivize the purchase of CNG, 18-wheelers or other types of vehicles?

ERIC MARSH: Yes, I probably can't get them all by memory but, you know, and probably the one that's probably most important in the United States is the NAT Gas Act that Boone Pickens has put forward. I think that'll move a long ways on transportation. And then you have the series of different state issues that are going on – one in North Carolina; there's been the one in Colorado – that look at natural gas for power generation and then they're going kind of state by state and so I think as time goes on, I think more states will begin to look at it as natural gas and coal prices are fairly competitive. And yet you look for that opportunity to reduce your emissions and really the opportunity in the United States and Canada is, is that natural gas available right now, it's an under-utilized capacity… that has under-utilized capacity that we could bring forward right now and perhaps get as much as a 25 percent reduction in emissions without much capital investment.

UNIDENTIFIED SPEAKER: Eric, you also have the incentives at the state levels for auto purchases and for…

ERIC MARSH: You do.

UNIDENTIFIED SPEAKER: The federal level as well.

ERIC MARSH: You bet. There's certain states, such as Colorado, where we operate, Louisiana, where you have incentives to buy natural gas vehicles and put in infrastructure and they're all different but they really help start moving the needle that way.

UNIDENTIFIED SPEAKER: It's usually somewhere in the order of several thousand dollars per vehicle; I think, in Colorado it was around $4,000 a vehicle?

Back to Agenda

ERIC MARSH: That's correct. It's about $4,000 for Colorado and then it can be up to 50 percent of your infrastructure, if you want to put in a fill station at your home and, so no, those things help a lot.

UNIDENTIFIED SPEAKER: And Ontario has one as well.

ERIC MARSH: Ontario has one, you bet.

UNIDENTIFIED SPEAKER: I'm just wondering if you could give us your thought process around LNG? Some brief comments were made at the beginning of the sessions and I guess you believe prices are going to be higher elsewhere and so it just won't come into the continent. But does the overhang of projects worry you with regards to the $6.50 long-term price? And just some thoughts around LNG and how that's going to impact the market.

UNIDENTIFIED SPEAKER: Okay, well there are… what is it, about 15 Bcf a day, I think, of LNG projects, either re-gasification projects either existing in North America or will be built in the last… or the next couple of years? That about right?

UNIDENTIFIED SPEAKER: Yes, there's currently 13 Bcf…

UNIDENTIFIED SPEAKER: Thirteen.

UNIDENTIFIED SPEAKER: Of capacity with an additional 6 coming on by the end of next year.

UNIDENTIFIED SPEAKER: Yes, and you know, we don't imagine that much more gas is going to be coming in to North America. I see LNG right now as floating storage and it'll go to the highest priced market and we don't think that North America's necessarily going to be that place. What's happening in North America on the shale gas plays, we think will most likely happen in parts of Europe and Asia as well and… But it's unlikely to come on in those countries… well, maybe in Asia but definitely not in Europe as low cost as it is in Canada. There are a number of structural issues in Europe that will probably make the cost a little bit higher. So it should be a more competitive market for the LNG to land than in North America.

And, you know, when we look at the potential for oversupply in North America, we see that the possibility is that we should have more export facilities built instead of import facilities, or at least balance it. But again, you know, there's one being talked about at Kitimat and a few other people are

Back to Agenda

discussing different possibilities but those are only in the order of Bcf per day. With the potential that we have for oversupply in North America, I'd get really interested if we were talking about a number like 10 Bcf a day potential or something higher than that. But it's only going to be able to make sense if meeting the supply cost in North America, which we're saying is going to be around $6 or so, it needs to get a price which is probably about $4 or $5 higher than that in the international market before it would make economic sense.

And so will natural gas in the international market continue - or LNG in the international market - continue to be priced off of oil in the same way as it has in the past? If that's the case, it could make economic sense. If the world is flush with natural gas, then we may not see those kind of contracts done in the future. But for now, I understand that those kind of contracts still exist and so there may be a market opportunity for developing LNG in North America.

BILL OLIVER: Any further questions? If not, that concludes the formal part of the program this morning. Again, we'd really like to thank all of you for taking your time to attend and would like to invite you all for lunch. We have lunch right next door in the adjoining room and all the Encana team will be available for some further discussion. So thank you once again.

*****

Back to Agenda