ENERGY MADE SIMPLE

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GLOBAL ENERGY RESEARCH

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Energy Made Simple (First Edition)

Value Drivers for Investment Professionals

Equity Research

Greg Pardy (Analyst) Co-Head Global Energy Research
(416) 842-7848 greg.pardy@rbccm.com

Kurt Hallead (Analyst) Co-Head Global Energy Research
(512) 708-6356 kurt.hallead@rbccm.com

Energy Exploration, Production & Services

RBC Dominion Securities Inc.

Integrated Oil, Senior E&P, and Oil Sands

Greg Pardy (Analyst)
(416) 842-7848
greg.pardy@rbccm.com
Carson Tong (Associate Analyst) (416) 842-8588
carson.tong@rbccm.com
Dillon Culhane (Associate)
(416) 842-7915
dillon.culhane@rbccm.com

Junior & Intermediate E&P

Michael Harvey (Analyst)
(403) 299-6998
michael.harvey@rbccm.com
Eric Gallie (Associate)
(403) 299-7434
eric.gallie@rbccm.com
Anthony Petrucci (Analyst)
(403) 299-6958
anthony.petrucci@rbccm.com
Shailender Randhawa (Analyst)
(403) 299-6576
shailender.randhawa@rbccm.com

Oil Sands / Intermediate E&P

Mark J. Friesen (Analyst)
(403) 299-2389
mark.j.friesen@rbccm.com
Sam Roach (Associate)
(403) 299-5045
sam.roach@rbccm.com

Oil & Gas Equipment and Services

Dan MacDonald (Analyst)
(403) 299-2394
dan.macdonald@rbccm.com
Matthew Vines (Associate)
(403) 299-5042
matthew.vines@rbccm.com

RBC Capital Markets LLC

Oil & Gas Equipment and Services

Kurt Hallead (Analyst)
(512) 708-6356
kurt.hallead@rbccm.com
Justin Sander (Associate)
(512) 708-6386
justin.sander@rbccm.com

US E&P

Scott Hanold (Analyst)
(512) 708-6354
scott.hanold@rbccm.com
JB Jouve (Associate)
(512) 708-6357
jb.jouve@rbccm.com
Leo Mariani (Analyst)
(512) 708-6381
leo.mariani@rbccm.com
Kyle Rhodes (Associate)
(512) 708-6342
kyle.rhodes@rbccm.com
Brad Heffern (Associate)
(512) 708-6311
brad.heffern@rbccm.com

RBC Europe Limited

International E&P

Al Stanton (Analyst)
44 131-222-3638
al.stanton@rbccm.com
Nathan Piper (Analyst)
44 131-222-3649
nathan.piper@rbccm.com
Theresa Pfab (Associate)
44 131-222-3696
theresa.pfab@rbccm.com

James Hosie (Analyst)
44 131-222-3695
james.hosie@rbccm.com

Integrated Oil & Gas

Peter Hutton (Analyst)
44 207-029-7650
peter.hutton@rbccm.com
Kristine Beese (Associate)
44 207-029-7556
kristine.beese@rbccm.com

International Oil Services

Bastien Dublanc (Analyst)
44 207-653-4620
bastien.dublanc@rbccm.com
Katherine Tonks (Analyst)
(+44) 207 029-0787
katherine.tonks@rbccm.com

Royal Bank of Canada - Sydney Branch

International E&P

Andrew Williams (Analyst)
+613 8688 6578
andrew.williams@rbccm.com
Josh Waudby (Associate)
+613 8688-6571
josh.waudby@rbccm.com

Energy Infrastructure & Technology

RBC Dominion Securities Inc.

Power & Pipelines, Midstream

Robert Kwan (Analyst)
(604) 257-7611
robert.kwan@rbccm.com
Nelson Ng (Analyst)
(604) 257-7617
nelson.ng@rbccm.com
Danny Hung (Associate)
(604) 257-7064
danny.hung@rbccm.com

Kelsey Roste (Associate)
(604) 257-7383
kelsey.roste@rbccm.com

RBC Capital Markets LLC

MLPs, Midstream

TJ Schultz (Analyst)
(512) 708-6385
tj.schultz@rbccm.com
David Askew (Associate)
(512) 708-6355
david.askew@rbccm.com
John Ragozzino (Analyst)
(512) 708-6335
john.ragozzino@rbccm.com
Elvira Scotto (Analyst)
(212) 905-5957
elvira.scotto@rbccm.com
Ashok Subramanian (Associate)
(212) 618-3304
ashok.subramanian@rbccm.com

Power & Utilities

Shelby Tucker (Analyst)
(212) 428-6462
shelby.tucker@rbccm.com
Ellen Ngai (Associate)
(212) 558-0412
ellen.ngai@rbccm.com
Insoo Kim (Associate)
(212) 905-2995
insoo.kim@rbccm.com

RBC Europe Limited

U.K. Renewable Energy

Nick Hyslop (Analyst)
44 207-653-4600
nick.hyslop@rbccm.com
Andrew Dunn (Associate Analyst)
44 207-029-7877
andrew.dunn@rbccm.com

Credit Research

RBC Dominion Securities Inc.

Investment Grade

Matthew Kolodzie (Analyst)
(416) 842-6152
matthew.kolodzie@rbccm.com
Steve Choi (Associate)
(416) 842-6140
steve.choi@rbccm.com

High Yield

RBC Capital Markets LLC
Adam Leight (Analyst) Head of High Yield Research
(212) 618-3250 adam.leight@rbccm.com
Robert Szuhany (Associate)
(212) 437-9246
robert.szuhany@rbccm.com
Justin Schleifer (Associate)
(212) 437-9958
justin.schleifer@rbccm.com

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Abbreviations

bbl/d	Barrels of oil per day	mmbtu	Million British thermal units
bcf	Billion cubic feet	mcf	Thousand cubic feet
bcfe	Billion cubic feet equivalent	mcf/d	Thousand cubic feet per day
boe	Barrels of oil equivalent	mmcf	Million cubic feet
boe/d	Barrels of oil equivalent per day	mmcfe	Million cubic feet equivalent
mmbbl/d	Million barrels per day	mmcf/d	Million cubic feet per day
mbbl	Thousand barrels	tcf	Trillion Cubic Feet
mboe	Thousand barrels of oil equivalent		

Natural Gas converted into equivalence on the basis of 6 mcf = 1 boe

Energy Defined – Crude Oil & Natural Gas

We view crude oil and natural gas as two of the most important energy sources in the world. These two naturally occurring mixtures are found in sedimentary rocks, among others, formed over millions of years by the accumulation of sand, silt, and the remains of plants and animals.

Oil and gas provide many of the products that people use or consume every day, ranging from electronics, cosmetics and clothing, to heating fuel, transportation fuel, and electricity. The oil and gas industry creates employment and fosters supporting industries (i.e., steel, transportation, engineering, etc), while its direct and indirect income contribute significantly to the global economy. Producing companies pay royalties and taxes in most jurisdictions that boost government revenues.

Value Chain

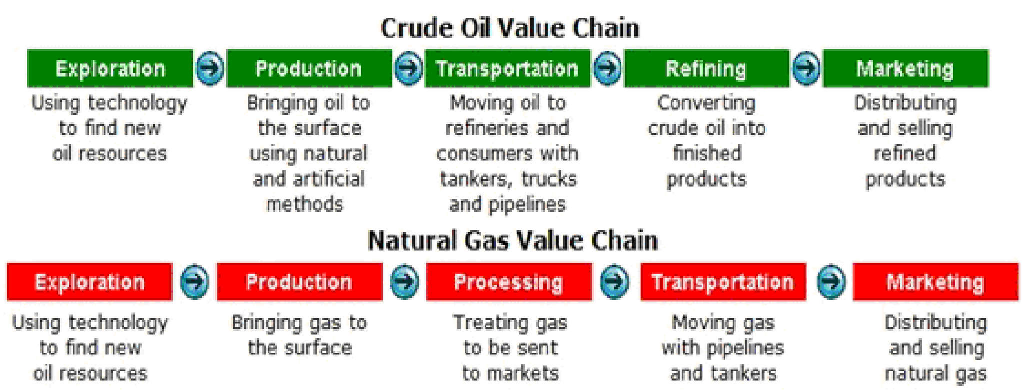
The oil and gas industry can be sub-divided into three components of the value chain: Upstream, Midstream, and Downstream.

The oil and gas industry can be sub-divided into three components of the value chain: Upstream, Midstream, and Downstream, as outlined below:

- **Upstream.** The upstream segment includes the exploration and production (E&P) of oil and natural gas and all associated activities. Aside from pure E&P companies, this segment also encompasses many service companies such as rig operators, seismic and drilling contractors, pressure pumpers, engineering and scientific firms, and suppliers. One key measure of profitability for upstream producers is the **field netback**, or gross profit generated per barrel of oil equivalent produced, factoring in standard costs. It is calculated as: *Realized Price - Royalties - Operating Costs - Transportation Costs* (all on an equivalent per-barrel basis).
- **Midstream.** The midstream segment transports oil and natural gas from upstream producing areas to downstream refineries. This segment consists of pipeline systems to move hydrocarbons, processing facilities that extract sulphur and natural gas liquids, storage facilities for end products, and other transportation systems to move products by truck, rail, or tanker.
- **Downstream.** The downstream segment refines, markets and distributes end user products, such as gasoline, jet fuel, heating oil, diesel, and propane, to name a few. This segment consists of refineries, petrochemical companies, natural gas distribution utilities, oil product wholesalers and local retail fuelling stations. The wide range of end products varies according to the type of crude oil processed, along with the design and complexity of each refinery. Processes can be altered to produce more gasoline in the summer months or more heating oil in winter.

Many companies choose to focus on one segment of the value chain, such as pure E&P companies (upstream) like Canadian Natural Resources Ltd., pipeline companies (midstream) such as Enbridge Inc. or TransCanada Corp., or refiners (downstream) such as Valero Energy Corp. However, many also choose an integrated business model, exploring for and producing hydrocarbons, transporting them through their own pipelines, and refining them into end products at their own refineries. These companies are referred to as “integrated” oil & gas companies, and include such large firms as ExxonMobil, BP, and Chevron.

Exhibit 1: Oil & Gas Value Chain



Source: Oil & Gas Journal

Crude Oil

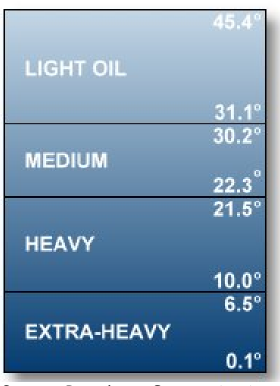
Crude oil is a naturally occurring liquid mixture of hydrogen and carbon atoms, referred to as hydrocarbons. These hydrocarbons are found in underground reservoirs within sedimentary rocks formed over millions of years, and are often mixed with natural gas, carbon dioxide, saltwater, sulphur and/or sand, which are separated from the liquid once extracted.

Global Commodity. Crude oil is viewed primarily as a global commodity since worldwide transportation by tankers is relatively inexpensive. Nonetheless, regional forces often affect crude prices, such as the case with the glut of WTI crude oil in North America (discussed below). Oil prices are set according to various quality benchmarks, and continually fluctuate according to market perceptions of global supply and demand. The Organization of Petroleum Exporting Countries (OPEC) influences world oil prices, but this influence has decreased over the years due to growing non-OPEC oil production. The global nature of crude oil is contrary to natural gas, which is more of a regionally priced commodity due to its higher cost of global transportation (discussed below) as it does not occur naturally in liquid form.

All else equal, lighter crude oils will be priced at a premium to heavier ones.

Gravity/Quality. The American Petroleum Institute (API) measures the "weight" or quality of crude oil on the API gravity scale. On this continuum, higher gravity equals lighter oil, which translates to better quality. All else equal, lighter crude oils will be priced at a premium to heavier ones. Another factor in crude oil quality is sulphur content – crude oils with higher levels of sulphur are known as "sour," while lower sulphur content grades are "sweet." Sweet crude is generally easier to refine and, thus, priced at a premium to sour crudes.

API Gravity



Source: Petroleum Communication Foundation/Canadian Centre for Energy Information

- **Light Oil:** Flows easily through wells and pipelines and can be refined into a large quantity of transportation fuels (gasoline, diesel, jet fuel). Light, sweet crude oil (such as West Texas Intermediate or "**WTI**") commands a relatively high price per barrel.
- **Heavy Oil:** Heavy oil is very carbon-rich and requires additional pumping in order to flow it through wells and pipelines. Heavy crudes are generally refined into a smaller proportion of natural gasoline and diesel fuel components, and require much more extensive, complex refining.[1] Furthermore, heavy oil is generally more difficult to extract than lighter crudes. Due to the more complex nature of extraction, transportation and refining, heavy oil has a lower price per barrel (discount) relative to light oil prices.
- **Bitumen:** Bitumen is a semi-solid hydrocarbon mixture, with the largest deposits located in the oil sands of Canada. This extra-heavy oil is either diluted (blended) with condensate or synthetic crude oil to produce diluted bitumen (dilbit) or synthetic bitumen (synbit) in order to flow it through pipelines. Blended bitumen can be sold directly to market at a discount to light crude oil, or upgraded to synthetic crude oil as discussed below.
- **Synthetic Crude:** This is produced by upgrading conventional heavy oil or oil sands bitumen into a synthetic light, sweet crude oil mixture through the addition of hydrogen and/or the removal of carbon.[2] All else being equal, synthetic crude generally sells at a premium to most other crude oil grades, although Syncrude synthetic oil from Canada's oil sands has recently traded at a discount to WTI due to pipeline constraints out of Western Canada.

Crude Oil Sources

Crude oil is produced using a variety of techniques from numerous different sources, ranging from conventional onshore oilfields to deepwater basins and the Canadian oil sands. The line between conventional and unconventional production is somewhat blurred, but conventional is generally defined as oil production from primary or secondary recovery methods that exclude oil from coal and shale, bitumen and extra heavy oil, and liquids from gas plants.

Many of the world's sources of conventional oil are in decline and the conventional oil reservoirs that were abundant and easy to find 30 years ago are now harder to locate and more costly to develop. As a result, crude oil production is increasingly targeting unconventional reservoirs – including shale oil, offshore deepwater oil and oil sands, which have a higher marginal cost of production than conventional sources.

Crude Oil Uses

Crude oil is a major source of energy and other everyday products around the world. It is extracted and refined into hundreds of end user products, including transportation fuels (gasoline, diesel), lubricants, heating fuels, plastics, clothing, cosmetics and electricity.

Natural Gas

Methane	C1	Higher value
Ethane	C2	
Propane	C3	
Butane	C4	
Pentane	C5	

Natural gas is a naturally occurring mixture comprised mainly of methane (CH_4), with varying amounts of heavier hydrocarbons such as ethane, propane, butane and pentanes (also known as **natural gas liquids** or NGLs). This mixture often contains other non-hydrocarbon substances such as carbon dioxide, nitrogen, sulphur and/or helium. Both NGLs and non-hydrocarbons are stripped from the methane at gas processing plants prior to its transportation and sale to end users with the NGLs also being sold for commercial use. Natural gas is often found in conjunction with oil and referred to as "associated gas," while "non-associated gas" accumulates on its own.

Natural Gas Sources

As technology advances, energy companies are extracting more and more natural gas using unconventional methods from challenging areas, including tight gas, shale gas, and coalbed methane, as discussed below:

- **Conventional Gas Accumulations:** Natural gas remains trapped by an overlying impermeable formation, called the seal, when it migrates from its source rock into an overlying sandstone formation.[3]
- **Tight Sand Gas:** Natural gas is diffused over larger areas instead of accumulating in larger concentrations, due to reduced rock permeability and limited migration ability.[4]
- **Shale Gas:** Natural gas that is trapped in shale formations, or fine-grained sedimentary rocks, from which it is unable to migrate. An abundance of North American shale gas discoveries in recent years has weighed on natural gas prices.
- **Coal Bed Methane (CBM)** is a type of natural gas produced from underground coal seams, and is virtually 100% methane.

Natural Gas Uses

Natural gas produces less carbon dioxide per unit of energy output relative to sources such as crude oil or coal. This, combined with the abundance of shale gas supply discovered in recent years, has led to power generation becoming one of the fastest growing uses of natural gas. It is also used as a fuel for cooking, heating, and transportation, with **Compressed Natural Gas (CNG)** seen as a cleaner-burning alternative to automobile fuels such as gasoline and diesel. Natural gas is also an important input for fertilizer production and in-situ oil sands production.

Regional Commodity

Unlike crude oil, natural gas prices are mainly determined by regional market forces due to the difficulty of storing or transporting natural gas by vehicle. Although natural gas can be shipped by pipeline over land, this is impractical across oceans. Due to its low density, natural gas must be liquefied before being transported across long distances by tankers, and then re-gasified at its destination. Essentially, it is transformed into **Liquefied Natural Gas (LNG)** prior to transport, and then returned to gas form upon arrival at its destination terminal.

This inability to easily transport natural gas over long distances explains the disconnect between gas prices in different parts of the world (i.e., Asia vs. North America). Nonetheless, the factors affecting pricing are similar to those affecting the globally priced crude oil: cost of extraction, distance between markets and producing areas, transportation charges, pipeline capacity, cost of competing energy sources, regional demand changes due to weather extremes, and overall balance between continental supply and demand.

Many companies are increasingly targeting liquids-rich gas plays, which offer attractively priced NGLs that can be sold in addition to the dry natural gas.

Natural Gas Liquids (NGLs)

Natural gas with high levels of NGL content is referred to as "liquids-rich" or "wet" natural gas. With the recent abundance of shale gas discoveries, many companies are increasingly targeting liquids-rich natural gas plays, which offer higher priced NGLs that can be sold in addition to the dry gas. NGLs have widespread uses as fuels for both heating and motor vehicles, and are also sources of feedstock for both petrochemicals and crude oil refining. Examples of liquids-rich plays include the Eagle Ford (Texas) and Duvernay (Western Canada) shales; while conversely, the Marcellus (northeastern U.S.) and Haynesville (Texas/Louisiana) shales are primarily dry gas plays.

Geology and Formative Processes

Oil and natural gas form over long periods (millions of years) as the remains of microscopic, photosynthetic organisms known as phytoplankton, which live near the surface of open aquatic environments, accumulate in subsided geographic features—referred to as sedimentary basins. Organic matter is buried by other sediments derived from weathered onshore landscapes that are transported to where they are ultimately deposited, generally in coastal environments, though lakes can also accumulate significant sedimentary deposits.

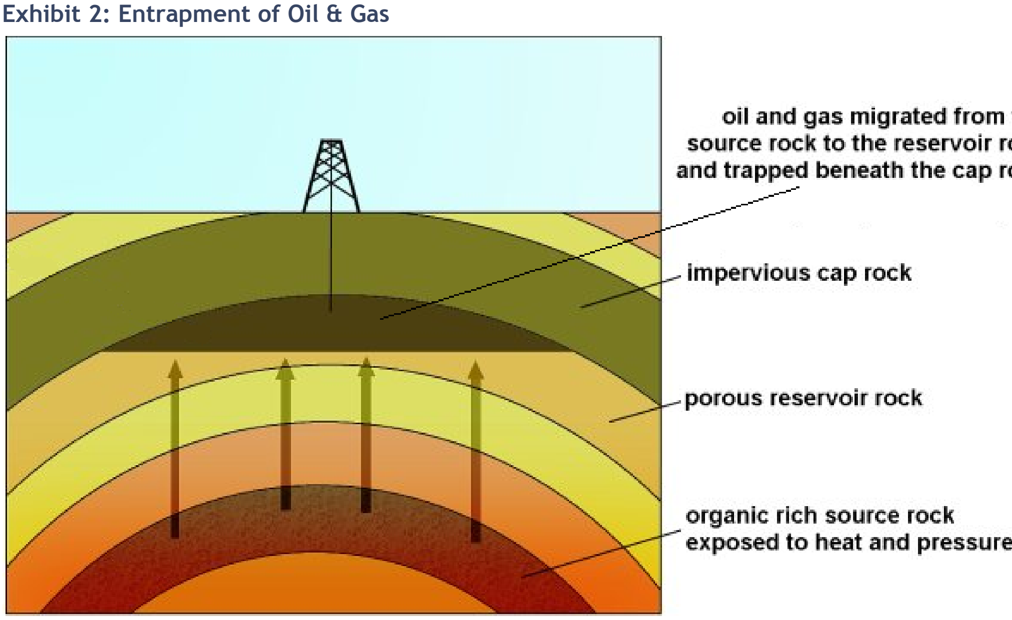
Pressure and heat resulting from the weight of these sediments alters carbon bonds in the organic matter, leading to the formation of a waxy material known as kerogen. In turn, with further pressure and heat, the kerogen "matures" and is converted to liquid (oil and NGLs) and gaseous (natural gas) hydrocarbons in a process known as catagenesis, which is not unlike the process by which petroleum distillates are refined, or cracked, in industrial refineries. Alternatively, natural gas can be formed by microorganisms referred to as methanogens that exist in extreme environments, including deep within the Earth's crust. Methanogens produce methane as a metabolic by-product.

Oil generally implies a lower a degree of maturation, NGLs represent intermediate maturation, with natural gas representing the final stage of hydrocarbon maturation.

Oil and gas are typically discovered in association with each other, although their proportion depends upon the processes driving maturation in the basin. Oil generally implies a lower degree of maturation, NGLs represent intermediate maturation, while natural gas represents the final stage of hydrocarbon maturation before being considered over mature. Over mature compounds lack the energy-storing bonds that make hydrocarbons commercially valuable.

As oil and gas are formed, their lower densities make them buoyant relative to the surrounding rocks and subsurface water. This causes them to migrate toward the surface as they are expelled from the source rocks from which the organic material was derived (Exhibit 2). Hydrocarbons tend to accumulate when they encounter confined porous rock units. In some cases, these units are also permeable, meaning that the porous spaces are connected to the extent that hydrocarbons can flow through them if exposed to differential pressures (e.g. a well borehole). Historically, it was these post-migration accumulations that were sought after for commercial exploitation. Today, these accumulations have come to be known as conventional reservoirs. However, with the advent of horizontal drilling and hydraulic fracture stimulation, the low-permeability source rock can also be produced economically. These accumulations are typically referred to as unconventional reservoirs; although, the term is something of a misnomer insofar as reservoir implies porosity and permeability conditions typically associated with conventional E&P.

Exhibit 2: Entrapment of Oil & Gas



Source: Discoveringfossils.co.uk

Reserves and Resources

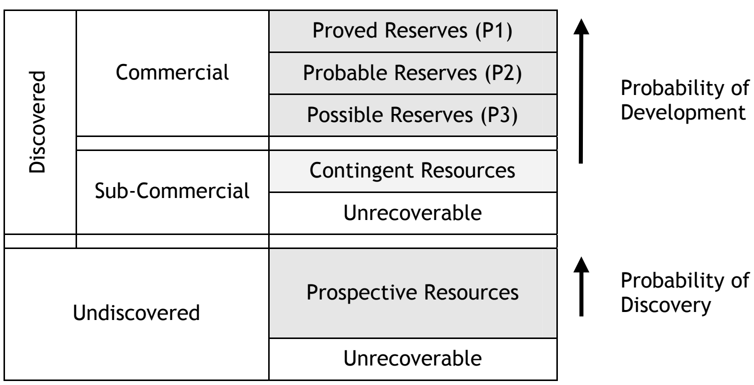
Oil and gas **reserves** and **resources** are volumes that are anticipated to be commercially recoverable at some point in the future. These reserves are located in underground reservoirs, and cannot be readily inspected or quantified with precision. Instead, reserve estimates are made based on the evaluation of data, which provides evidence of the quantity of hydrocarbons present in a given reservoir. Reserve estimators are highly-skilled professionals who utilize their experience and judgment when calculating these volumes, which inherently involves a degree of subjectivity and uncertainty.[5] However, these estimates are necessary in order to determine whether it is economic to develop a discovered field, balancing the projected reserves against the investment required.

There is a 50% probability that total production will at least equal the sum of proved + probable reserves.

As outlined in Exhibit 3 below, the Society of Petroleum Engineers classifies reserves into three categories: Proved, Probable and Possible. Proved reserves (also referred to as P1 or 1P) are estimated with reasonable certainty to be commercially and economically recoverable given expected prices, operating techniques, and fiscal regimes. The quantity of reserves quoted under this category have a 90% probability of being produced.[6] Probable reserves (P2) are unproven but more likely than not to be recovered, with a 50% probability that total production will at least equal the sum of proved + probable reserves (2P).[7] Finally, Possible reserves (P3) are deemed less likely to be recovered than Probable reserves, with at least a 10% probability of total recovery exceeding the sum of proved + probable + possible reserves (3P).[8]

Developed reserves are those expected to be recovered from existing wells, which can be further sub-classified as producing or non-producing.[9] Conversely, the expected recoverability of undeveloped reserves stems from new wells on undrilled land or from deepening existing wells to reach a new reservoir.[10] **Proved developed producing** reserves are commonly referred to as "PDP," while **Proved Undeveloped** reserves are known as "PUDs."

Exhibit 3: Reserves and Resources - Classification



Source: Society of Petroleum Engineers

Contingent resources have the potential for recoverability, but certain technical or commercial hurdles must be overcome.

Oil and gas **resources** have less certainty relative to reserves, since they are not yet technically or commercially recoverable, and can be classified as either **Contingent** or **Prospective.** Essentially, existing technology dictates that only a certain proportion of resources can be produced economically at any given time. Furthermore, transportation routes to market are critical because resources may not be commercial if there is no infrastructure in place (i.e., pipelines) to deliver them to downstream markets. Contingent resources have the potential for recoverability, but certain technical or commercial hurdles must be overcome before increasing the probability of recovery. Prospective Resources are volumes that are estimated to be potentially recoverable on the basis of indirect evidence from reservoirs that have not yet been drilled. For resources to be upgraded from the prospective to the contingent category, hydrocarbons must be actually discovered and analyzed further.[11]

In general, for quantities to be upgraded (i.e., from resources to reserves or from possible to probable), additional certainty of recoverability must be established by gathering more data. This can be accomplished through additional drilling, closer monitoring of production volumes, or institution of a pilot project, among other things.[12]

Reserves - Valuation Metrics

It is industry convention to look at the sum of proved plus probable (2P) reserves.

Oil and gas reserves are used as an objective measure of company value by investors, regulators, and governments alike. Indeed, any abrupt decline in a company's reserve base would likely lead to material negative effects on its share price. In merger, acquisition, and divestiture transactions, the price relative to the associated resource base is usually quoted as an important metric (please refer to the "Valuation: Trading Multiples" section for more details). Although industry convention may look at proved plus probable (2P) reserves as the best estimate of recoverability from committed projects, an assessment of the total value of a company's resource base should be comprehensive, including both reserves and resources.[13]

Reserves - Operational Metrics

E&P companies are also evaluated on reserve growth, the efficiency of replacing production with new reserves, the cost at which new reserves are added, and the remaining life of existing reserves.

Reserve Life Index (RLI): This is calculated as the reserve base of a given company or field, divided by the annual production from that company or field. For instance, a company with a resource base of 220 mmboe that produces 75,000 boe/d would have an RLI of roughly 8 years.

Reserve Replacement Ratio: This is a company's reserve additions for a given year divided by its production for that year. For example, a company that added 30 mmboe of proven (1P) reserves in 2011 and produced 25 mmboe during the same year would have a 1P reserve replacement ratio of 120% of production. If that company added 40 mmboe in proved + probable (2P) reserves, its 2P reserve replacement ratio would be 160% . Reserves can be added through new discoveries, extensions of existing discoveries, and/or improved recovery factors. Acquisitions, dispositions, economic factors and technical revisions can also increase or decrease reserve balances.

Finding & Development (F&D) Costs: This capital efficiency metric is expressed as the capital expenditures for a given period divided by the associated reserve additions. Essentially, it measures the capital cost of finding and developing reserves on a $/boe basis. F&D costs can also be expressed including acquisitions, known as **Finding, Development & Acquisition (FD&A) Costs,** and/or including the change in **Future Development Costs (FDC)**, which refer to the cost of developing reserves (i.e., placing them on production) in the future. Please see examples below:

1. **F&D Costs:** Assume Company A spent $5.0 billion on upstream capital expenditures (before acquisitions) in 2011, and added total proven reserves of 100 mmboe and probable reserves of 50 mmboe (both prior to production). Company A's F&D cost would be $50/boe[i] on a proved (1P) basis, and $33.33/boe[ii] on a proved + probable (2P) basis.
2. **FD&A Costs:** Assume Company A spent an additional $750 million on net acquisitions this year to add net proven reserves of 20 mmboe and net probable reserves of 17 mmboe. This would translate to a 1P FD&A cost of $48/boe[iii], and a 2P FD&A cost of $31/boe[iv].
3. **F&D Costs (including FDC):** Further to example 1, assume company A's future development costs increased by $350 million during 2011. Adding this change in FDC to Company A's upstream capital expenditures would translate to F&D costs (including change in FDC) of $53.50/boe[v] (1P basis) and $35.67/boe[vi] (2P basis).

Typically, F&D costs are evaluated on an average basis over three or five years, since capital expenditures and reserve additions can vary widely in any given year. A company may add significant reserves one year without spending much capital, then subsequently spend significant capital over the next few years to develop these reserves (with minimal additions). In this case, the F&D cost would be artificially low in year 1, and artificially high over subsequent years. For oil sands companies, F&D metrics are less relevant since massive reserve additions take place upfront, with the bulk of development capital spending occurring in later years.

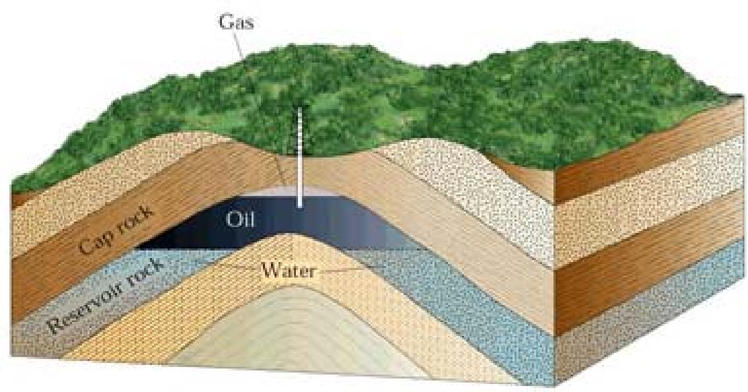
[i] $50/boe = $5.0 billion / 100 mmboe
[ii] $33.33/boe = $5.0 billion / (100 + 50 mmboe)
[iii] $48/boe = ($5.0 billion + $0.75 billion) / (100 + 20 mmboe)
[iv] $31/boe = ($5.0 billion + $0.75 billion) / (100 + 50 + 20 + 17 mmboe)
[v] $53.50/boe = ($5.0 billion + $0.35 billion) / 100 mmboe
[vi] $35.67/boe = ($5.0 billion + $0.35 billion) / (100 + 50 mmboe)

Crude Oil: Conventional Production

Oil has become the world's most important source of energy due to its high energy density, easy transportability, and relative abundance. In the early twentieth century, oil exploration began in North America, with the United States becoming a leading global producer by the mid-1900s. During the 1970s[14] U.S. oil production plateaued, eventually allowing Saudi Arabia and Russia to surpass it as the leading global producers. More than 80% of the world's proven oil reserves are located in OPEC Member Countries (65% of the OPEC oil reserves are located in the Middle East).[15]

Crude oil is usually found in association with natural gas in the reservoir, and since the composition of gas is lighter, the associated gas forms a 'gas cap' over the petroleum (Exhibit 4). Oil can be found in different forms, including as a semi-solid state mixed with sand and water, as in the Athabasca oil sands in Canada, where it is usually referred to as crude bitumen.

Exhibit 4: Cross Section of an Oil and Gas Reservoir



Source: U.S. Geological Survey

Conventional oil production is from primary or secondary recovery methods that exclude oil from coal and shale, bitumen, deepwater oil, and NGLs.

Oil will normally be classified into **conventional** and **non-conventional** categories but unfortunately there is very little agreement on the exact boundaries of these terms. Generally, conventional is defined as oil production from primary or secondary recovery methods that exclude oil from coal and shale, bitumen and extra heavy oil, and liquids from gas plants (natural gas liquids, or "NGLs"). Primary recovery is the extraction of resources through drilling wells and by relying on natural pressure and pumping to recover the oil. Secondary recovery involves the injection of water and other substances to increase reservoir pressure to recover the oil. Both of these recovery methods will be discussed in greater detail below. For the purposes of this report, "tight oil" drilling, through the implementation of horizontal drilling and multi-fracture technology, will fall under the definition of conventional oil production.

Conventional oil has a characteristic of a depleting profile, as production rises rapidly to a peak (or multiple peaks) before declining hyperbolically. Many of the world's sources of conventional oil are in decline. The conventional oil reservoirs that were abundant and easy to find 30 years ago are now harder to locate and more costly to develop. The evolution of horizontal drilling over the past 10 years has allowed previously uneconomical reserves to be accessed. Although the projects are more economical, the decline rates of a horizontal well are usually much greater, forcing companies to fight constant declining base production levels.

Extraction

Geologists and geophysicists are at the frontier of any oil and gas company as they use well control and seismic surveys to search for geological structures that may form oil reservoirs. Seismic surveys involve creating a sound wave and observing the seismic response, providing information about the underground geological structures.

Once a reservoir has been identified, an oil well is created by drilling a hole into the reservoir rock with a drilling rig. Historically, oil reserves were only developed using vertical wells, but in recent years companies have been able to drill horizontally, increasing reservoir contact. The evolution of fracture stimulation techniques has allowed companies to flow more hydrocarbons from tight rock formations, which vary in tonnage, interval spacing and use of fluids, as engineers will design specific fracture techniques for a given formation.

Production

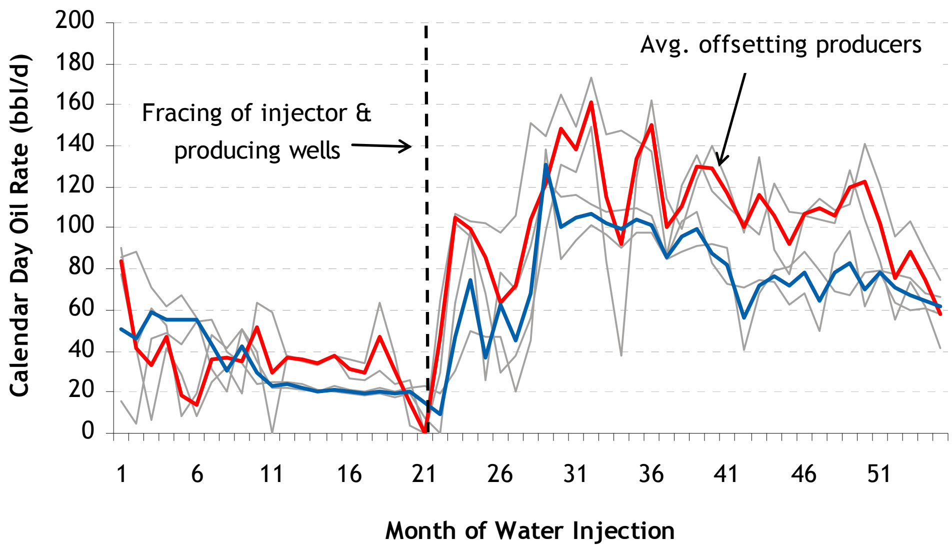
Recovery in the primary stage is typically 5%-20%.

Starting in the **primary recovery** stage, reservoir drive comes from a number of mechanisms, which can include natural water displacing oil downward into the well, expansion of natural gas at the top of the reservoir, gravity drainage resulting from the movement of oil from the upper to the lower parts of the reservoir, and through pumping of the well. Although the use of fracture technology employs outside sources to initiate the flow of the fluids, it is now being considered primary recovery as it becomes more of an industry standard. Recovery in the primary stage is typically 5%–20%.[16]

Recovery factor after primary and secondary oil recovery operations is over 20%.

In the **secondary recovery** stage, the company relies on the supply of external energy into the reservoir to increase reservoir pressure and, effectively, replace the natural pressure of the formation. As well as improving reservoir sweep, there are multiple techniques used including water injection, natural gas reinjection, and gas lift. The use of water injection involves drilling water injector wells and pumping water solution into the reservoir to increase its pressure. Each injector well will have a radius to which any offsetting producing well will see an increase in pressure and, therefore, production. Please refer to Exhibit 5 below for an example of a well transitioning from primary to secondary recovery using water injection. On average, the recovery factor after primary and secondary oil recovery operations can exceed 20%.[17]

Exhibit 5: Example Water Injection Project



Source: Accumap, RBC Capital Markets estimates

The final phase of production is called **tertiary** or **enhanced oil recovery** (EOR). This begins when secondary oil recovery isn't enough to continue adequate extraction, but only when the oil can still be extracted profitably. Tertiary recovery depends largely on the cost of the extraction method and current price of oil. There are various forms of EOR, including **thermally enhanced oil recovery** (TEOR), which heats the oil to reduce its viscosity and make it easier to extract. Steam injection is the most common form of TEOR, where a nearby plant will generate electricity and the waste heat is used to produce steam, which is then injected into the reservoir. A less used technique is to inject surfactants (detergents) into the reservoir to alter the surface tension between water and oil. Typically, EOR allows an incremental 5%–15% of oil to be recovered from the reservoir.[18]

Crude Oil: Benchmark Prices

Crude oil is categorized according to benchmarks, which are essentially groupings of crude oils with similar characteristics, mainly quality and location. These benchmark grades are used as a proxy for pricing across the global oil industry, and also as the basis for hedging, risk management, and term contract price formulas. Although important, all benchmarks are somewhat flawed in that they cannot fully represent the marginal supply of their respective grade.[19] This is outlined below in the discussion on two of the most recognized benchmark grades: the U.S.-based West Texas Intermediate (WTI) and the more globally referenced Brent crude oil benchmark. Effective benchmarks have high trading liquidity, consistent quality, a secure supply, and a diversified market of numerous buyers and sellers of the crude stream.[20]

Price Differentials

The actual selling price realized by producers of crude oil is not necessarily equal to a benchmark price.

The actual selling price realized by crude oil producers is not necessarily equal to a benchmark price. Instead, volumes are sold at a differential to the quoted benchmark – either a premium or a discount – depending on the specific benchmark used and the quality of the oil sold. Refining heavy crude oil with high sulphur content into finished products (i.e., gasoline or diesel) requires additional processing when compared to light, sweet crudes. Therefore, refiners pay less for heavy oils such as bitumen, compared to the light, sweet crude like WTI. The differential between these two prices is determined by the specific market for each type of oil; and all else being equal, the profits of heavy oil producers will suffer when this differential widens. Due to the rise of importance of the Canadian oil sands, U.S. oil refineries have made significant investments to expand their heavy oil processing capacity, which should serve to increase the demand for heavier crudes in the future.

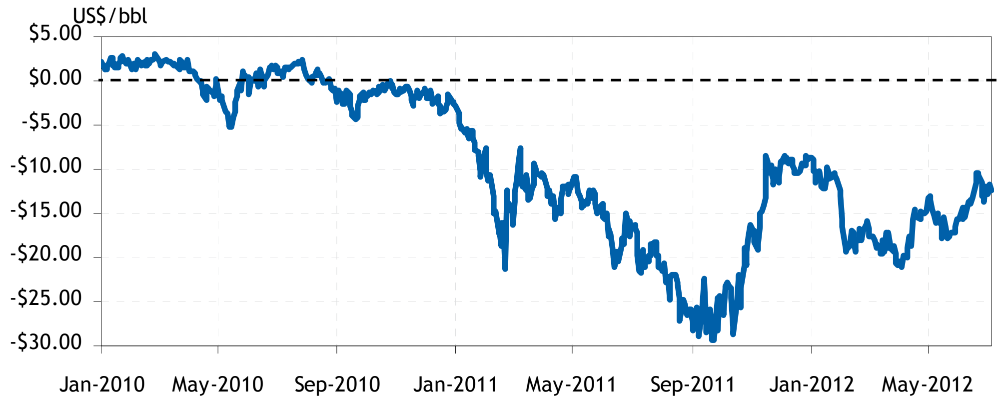
WTI vs. Brent

West Texas Intermediate was selected as the benchmark spot crude for the New York Mercantile Exchange's (NYMEX) futures contract in 1983.[21] WTI crude oil production is derived from West Texas and New Mexico, comingled with similar quality crude streams from central Texas, Oklahoma, and Kansas.[22] The popularity and success of the WTI benchmark stems not from its physical characteristics, but from its strong liquidity. Aside from serving as the main reference grade for the most heavily traded oil futures contract in the world, WTI is also used as the price benchmark for crude oil sales in the United States and Canada.

From a physical standpoint, WTI is not an ideal global benchmark due to its landlocked position in the United States and its failure to compete with other international crude oil grades, unless they are imported into the United States. Indeed, minor pipeline or refinery disruptions in the U.S. that have no international effect can have a profound bearing on WTI prices.[23] WTI traded at roughly a US$0.50/bbl premium to Brent prices during the five years leading up to late 2010, when things began to change. Physical constraints due to limited takeaway pipeline capacity at the delivery hub of Cushing, Oklahoma have created an oversupply of crude, weighing down WTI prices. Consequently, WTI has traded at a steep discount to Brent throughout 2011 and into 2012 (Exhibit 6), and this spread is destined to remain wide until further pipeline capacity moves into place.

Due to its disconnection from international crude prices, WTI's relevance as a global marker continues to steadily erode in favour of the Brent benchmark, which better reflects global oil fundamentals. Furthermore, prices for other types of crudes that are linked to WTI, such as Edmonton Light and Bow River Heavy (discussed below), will also remain detached from global oil prices until the takeaway bottleneck is resolved. Although its influence continues to wane, WTI will likely continue to be quoted as a proxy for global crude prices for some time, simply due to the huge volumes of NYMEX futures traded.[24]

Exhibit 6: WTI – Brent Spread



Source: Bloomberg

The Brent benchmark is a blend of various crude oils produced in the North Sea region of the United Kingdom and Norway. Brent is sold by a wide variety of producers and accepted by a wide variety of buyers, resulting in strong physical liquidity and price transparency for this benchmark blend.[25] In addition to being the dominant European benchmark, African-based crudes from countries such as Libya and Nigeria are also priced off of the Brent benchmark. Financially, although NYMEX futures are still the most heavily traded crude oil contract, Brent has seen a steady increase in traded volumes of futures and options since 2009. As discussed above, with the detachment of WTI from international oil prices, Brent has emerged as the primary global crude oil reference price and is increasingly being relied on in both the physical and financial oil market.

Brent has emerged as the primary global crude oil reference price.

Other Crude Oil Benchmarks

Aside from Brent and WTI, there are numerous other crude oil benchmarks around the world with varying degrees of quality. Some notable North American benchmarks are highlighted below:

Edmonton Par Light: Edmonton Par serves as the primary benchmark for light crude oil produced in Western Canada. Similar to WTI, Edmonton Par is a high-quality, low-sulphur content crude with an API gravity close to 40°. During the five years preceding 2011, Edmonton Par traded at an average discount of roughly US$2/bbl to WTI. However, this relationship reversed in April 2011 when Edmonton Par started trading at a premium to WTI, reflective of the supply glut at Cushing mentioned above. Since December 2011, Edmonton Par has reverted to trading at a discount to WTI, with differentials blowing out to US$28/bbl in April 2012, reflecting concerns over crude oil takeaway capacity from Western Canada and refinery turnarounds.

Western Canadian Select (WCS): WCS is a blend of Western Canadian conventional heavy and bitumen crude oil streams, mixed with sweet synthetic and condensate diluents in order to provide a suitable feedstock for U.S. Midwest refineries. With an average API gravity of 20.5° and 3.5% sulphur content, WCS is a heavy, sour crude oil which is similar in quality to Bow River, Mexican Maya and U.S. Gulf Mars blend. Launched in 2004, WCS producers are hoping that it will become a North American benchmark that can compete effectively with WTI and Brent. In order to do so, WCS is being marketed increasingly toward the U.S. Gulf Coast refiners, where demand for heavy crudes is projected to increase as declines in Mexican heavy oils and increased shipping of Venezuelan heavy crude to Asia takes place.[26]

Bow River Heavy: The Bow River Heavy Oil blend serves as a primary benchmark for heavy, sour conventional crude oil in Alberta and Saskatchewan. With an average API gravity of roughly 22° and a 2.5% sulphur content[27], Bow River trades at a discount to the Edmonton Par Light oil posting. Bow River production originates from a wide array of producing companies, and is generally shipped to the U.S. Midwest refiners.

Mexican Maya: Mexican Maya is a heavy, sour crude oil blend with an API gravity averaging from 21° to 22°, and sulphur content above 3%. Production is blended from the super-giant Cantarell field and the Ku-Maloob-Zaap fields. State-owed Pemex is the sole producer of Maya, which is sold mainly to U.S. customers who process this low-quality crude at complex Gulf Coast refineries. Although Maya has historically traded at a discount to WTI, this relationship reversed in mid-2011, reflecting the WTI supply glut at Cushing. During the first five months of 2012, Maya has traded at an average premium of almost US$6/bbl to WTI. Although the Maya stream is in rapid decline, it still serves as the lifeblood of Mexico's crude oil industry, representing over 58% of production and 87% of exports in 2009.[28]

West Texas Sour (WTS): Although less popular than WTI, WTS remains one of the most widely traded U.S. domestic crude oil benchmarks. As a medium-gravity, high-sulphur crude (~1.3%), this blend is best suited for refineries that possess upfront hydrotreating capabilities. WTS is an important benchmark for onshore medium-sulphur U.S. domestic crudes, and its discount to WTI is a good proxy for the market's view on quality differentials. WTS is comprised of a broad range of fields in the West Texas-Eastern New Mexico Permian Basin area.[29]

Oil Sands: The Driving Force of Canada's Production Growth

What Are the Alberta Oil Sands?

The Alberta oil sands contain ~170 billion barrels of proven reserves, the third largest proven crude oil reserve in the world. The Canadian Association of Petroleum Producers (CAPP) forecasts that production from the oil sands could contribute approximately 1.5 mmbbl/d to Canada's production growth in the next decade, doubling current production capacity.

Oil sands will typically not flow under natural reservoir temperatures.

Oil Sands vs. Conventional Oil – The two major differences between conventional oil & gas versus oil sands are: (1) oil sands will typically not flow under natural reservoir temperatures, therefore traditional extraction methods are insufficient; and (2) oil sands are a mixture of bitumen (heavy oil), water and sand.

Three Distinct Areas – There are three designated oil sands development areas in Alberta (Exhibit 7), with the bulk of activity focused on the Athabasca region. While the mineable oil sands deposits are all held in the northern Athabasca region, the Cold Lake region is predominantly developed using Cyclical Steam Stimulation (CSS), and the Peace River area is relatively less mature than the other two.

Exhibit 7: The Oil Sands Regions

Source: Energy Resources Conservation Board and RBC Capital Markets

RBC Capital Markets®

Oil Sands Reservoirs Are All Different – The predominant producing formation in the oil sands is the McMurray Formation, where a clastic rock holds the bitumen deposits. Other clastic formations include the Wabiskaw, Clearwater and Grand Rapids Formations. More recently, large deposits of bitumen held in carbonate formations have been identified as potential candidates for production, and are commonly known as the Bitumen Carbonates. Examples of Carbonate reservoirs include the Grosmont and Leduc Formations; however, these have not yet been commercialized.

PADD II (the U.S. Midwest) is the primary market for bitumen sales.

Heavy Oil Markets – The U.S. is divided into five Petroleum Administration for Defence Districts, or "PADDs." PADD II represents the U.S. Midwest and is the primary market for bitumen sales from the Canadian oil sands. In 2012, 819 mbbl/d of Canadian heavy oil was refined in PADD II, compared to 200 mbbl/d refined in Western Canada. Canadian heavy oil producers believe that access to markets such as PADD III (the U.S. Gulf Coast) and/or the Canadian West Coast to reach markets in Asia would improve realized pricing due to increased demand for heavier crudes.

How Do Oil Sands Producers Recover & Market Bitumen?

There are two methods of bitumen recovery in the oil sands: mining and in-situ.

Recovery

Mining – Truck and shovel surface mining has been used to develop shallow (<75m) bitumen deposits since 1967 in a concentrated 1.2 million acre area north of Fort McMurray, Alberta. Surface mining is a relatively mature technology that is simple and effective; recovery factors of ~95% are the norm, however, upfront capital and operating costs are significantly higher than those of in-situ projects. See Exhibit 8 for a schematic of the oil sands mining process.

In-Situ – Deeper bitumen deposits (generally >100m) can be developed using in-situ methods. There are currently two commercially active in-situ technologies**: CSS (Cyclical Steam Stimulation)** and **SAGD (Steam Assisted Gravity Drainage)**; and a plethora of experimental technologies currently in the testing/piloting stages, such as Toe-to-Heel Air Injection (THAI), Thermal Assisted Gravity Drainage (TAGD) and Electro-Thermal Dynamic Stripping Process (ET-DSP). Because bitumen is immobile in its native form, energy (usually heat) must be applied to the reservoir to mobilize the bitumen for it to be pumped to the surface. See Exhibit 8 for a schematic of the SAGD and CSS processes.

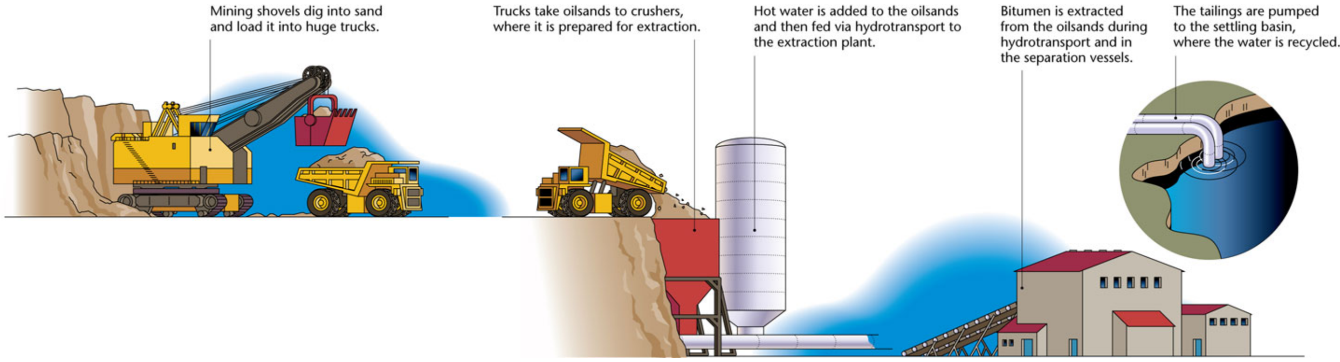
Marketing

Upgrading – Since produced bitumen is too viscous to be transported via pipeline, producers must either upgrade the bitumen to synthetic crude oil or blend it with a lighter oil to reduce its viscosity. Mining projects have historically been integrated with upgraders that convert raw bitumen into synthetic crude oil. For simplicity, one can think of an upgrader as the front-end of a refinery. The upgrading process will produce a higher value liquid product, however, some yield loss usually occurs.

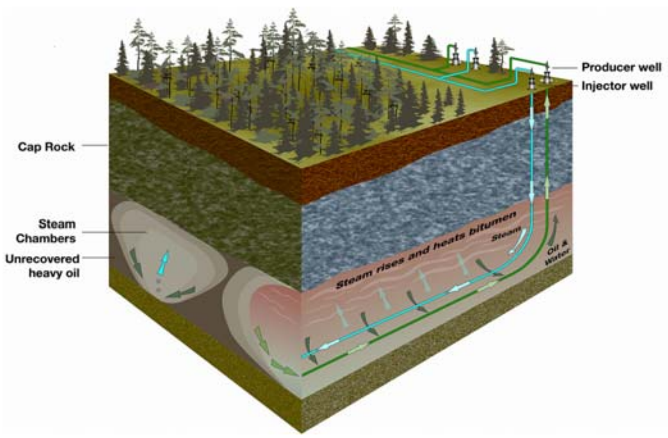
Blending – Bitumen produced using in-situ methods is generally blended with a lighter oil (either condensate or synthetic crude oil) to produce diluted bitumen (dilbit) or synthetic-bitumen (synbit). Dilbit usually consists of two parts bitumen and one part condensate (a 33% blend ratio). Synbit usually consists of one part bitumen and one part synthetic crude oil (a 50% blend ratio). Condensate is piped, trucked and railed from all over North America to the oil sands, and synthetic crude oil can be purchased from upgraders in Alberta.

Exhibit 8: Oil Sands Recovery Techniques

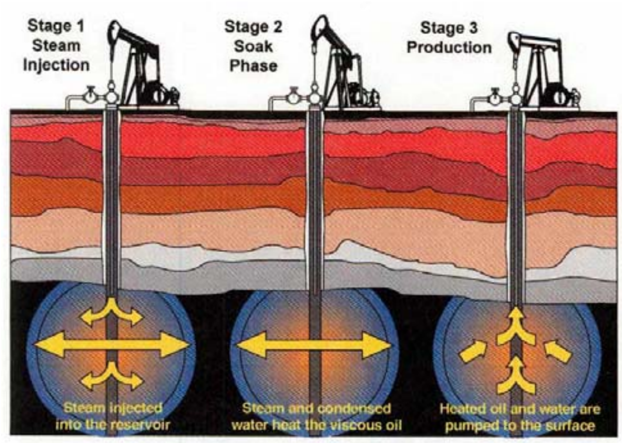
Oil Sands Mining



Steam Assisted Gravity Drainage (SAGD)



Vertical Cyclical Steam Stimulation (CSS)[1.]



1. Horizontal CSS is also used

Source: Oil Sands Developers Group and Strategy West

What Makes the Oil Sands Project Life Cycle So Long?

Oil sands development has a long project life cycle compared to its conventional counterparts. Projects require large up-front capital costs, long lead time to production, and pay-out over a long period of time. Typical lead time to production can be well over five years from the time a lease is acquired. We outline a typical project life cycle below, and a graphical representation in Exhibit 9.

Lease acquisition and Exploration – Initially, mineral rights are sold in Crown Land Sales via a public bidding system. The oil sands land rush took place from 2006 to 2008, leaving very little prospective land available for acquisition today. Scarcity of resource has contributed to increased oil sands valuations over time. Today, most lease acquisitions take place via registered transfer of rights between the lease holders and interested buyers.

After sufficient delineation, a company may book Contingent Resources.

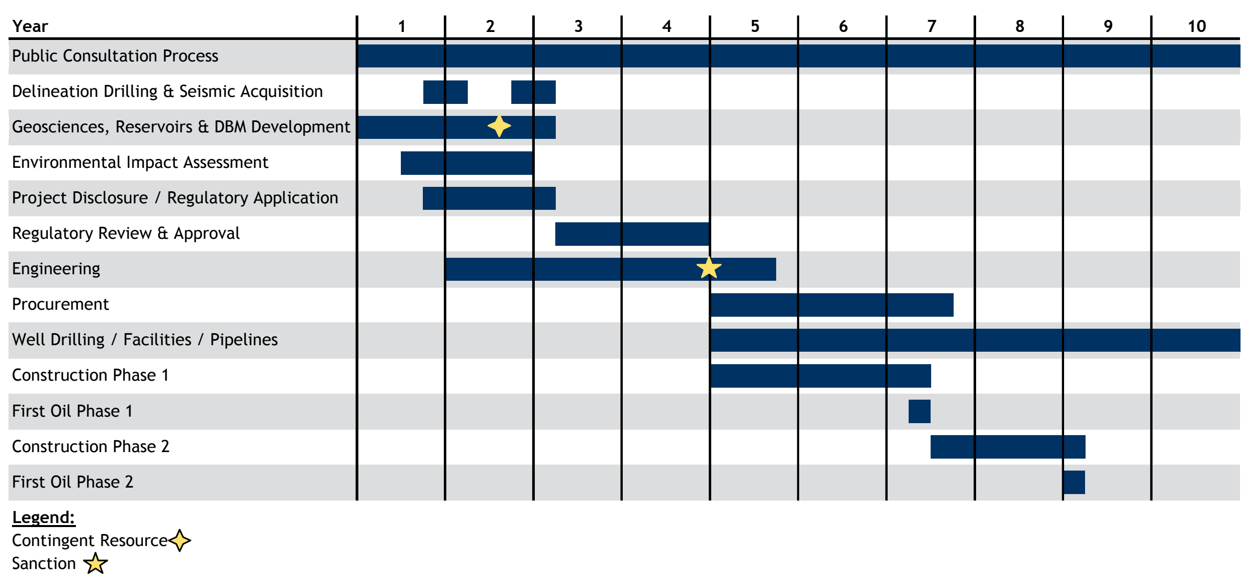
Delineation – Core-hole drilling, seismic and other geological and geophysical appraisal techniques are used to define the resource prior to regulatory application. Depending on the size of the resource and nature of the project, the delineation process can take two or more winter drilling programs. Delineation is generally conducted in the cold winter months due to access restrictions during shoulder months. After sufficient delineation, a company may book Contingent Resources (as discussed in the *Reserves and Resources* section above).

Regulatory – Alberta's oil sands regulation is far more stringent than conventional oil and gas regulation. A company must submit a detailed regulatory application for each project to the government, which often takes 18 months or more to approve. The application addresses a number of issues including environmental, social and economic impact assessments as well as detailed reservoir information and process descriptions. During the regulatory review process, the government will often send Supplemental Information Requests (SIRs) to the company to clarify certain aspects of the application and address any concerns.

Development – Due to the sheer scale of oil sands development, projects are often constructed and commissioned in multiple phases. Manageable-sized phases help control the cost and efficiency of labour and materials, while allowing management teams to incorporate new technologies and apply knowledge from earlier phases to future ones.

Reclamation – Prior to project approval, a company must develop a plan to return the land to its original state. This is more important for mining projects, as there is much more land disturbance associated with mining compared to in-situ projects. Upon project completion and decommissioning, the company will replace soils, plant trees, restore ecosystems and monitor the reclamation process to ensure success.

Exhibit 9: Typical SAGD Project Timeline (2 Phase Development)



Source: Company reports and RBC Capital Markets

Oil Sands Terminology and Rules of Thumb

SORs measure the amount of steam injected per barrel of bitumen produced.

Steam-Oil-Ratios (SOR) – The most quoted performance metric for steam-based in-situ projects is the SOR, which measures the amount of steam that has to be injected per barrel of bitumen produced (SOR = Steam Injected / Oil Produced). In short, a lower SOR is better. Lower SORs contribute to lower operating costs and lower capital costs. Approximately 0.408 mcf of natural gas is required to transform one barrel of water into dry steam. Exhibit 10 provides a mapping of various wet and dry SORs to natural gas consumption requirements.

2P + Best Estimate: A resource evaluator will use a set of assumptions and available information including technology use, recovery factors and reservoir parameters to determine the size of the recoverable resource. Depending on the stage in the regulatory process, this recoverable resource may be classified as Reserves or Contingent Resource. For oil sands valuation metrics, it is common to use the sum of 2P Reserves and Best Estimate Contingent Resource for the resource size. A common valuation metric is Enterprise Value/boe of 2P + Best Estimate.

Reserve Life Index (RLI): One can use this tool to determine what project size a particular resource deposit could support. A typical rule of thumb is that a project's Reserve Life Index (RLI) should be around 30 years; therefore, if a company has 500 mmbbl of resource it could support a project capacity over 45 mbbl/d for 30 years (45,000 × 365 × 30 = 500 million).

A common valuation metric is Enterprise Value/boe of 2P + Best Estimate.

What Makes a Good Reservoir: In general, a good in-situ reservoir is thick, has high porosity, high bitumen saturation, and high permeability (particularly vertical permeability). Additionally, a lack of lean zones, areas of depleted top gas, bottom water, and interbedded shales all contribute to a more attractive reservoir for thermal development.

Cap Rock: Cap rock is essential for SAGD production, as it provides a barrier for steam containment. The integrity of a cap rock will determine the maximum operating pressure, and partially determine productivity of the project.

Cogeneration: Some oil sands projects are integrated with cogeneration power supply. A cogeneration unit or 'cogen' is a small gas-fired power plant which is used to supply electricity requirements for operations. A by-product of cogeneration is heat, which can also be used in the steam generation process.

Solvents: Injection of solvents has been used selectively in SAGD and CSS projects. The objective of solvent injection is to increase productivity (production rate per well pair) and efficiency (SOR).

Exhibit 10: Natural Gas Requirements under Various SOR Performance

Bitumen Production	Equivalent Steam Oil Ratio		Natural Gas Requirements: SAGD		CSS				
bbl/d	Wet	Dry	mmcf/d	mcf/bbl	mmcf/d	mcf/bbl	Solution Gas mmcf/d[(a)]	Net Natural Gas Usage mmcf/d	Net Natural Gas Usage mcf/bbl
35,000	2.7x	2.0x	28.9	**0.83**	30.8	0.88	(3.1)	27.7	**0.79**
35,000	3.0x	2.3x	32.1	**0.92**	34.2	0.98	(3.4)	30.8	**0.88**
35,000	3.3x	2.5x	35.3	**1.01**	37.7	1.08	(3.8)	33.9	**0.97**
35,000	3.6x	2.7x	38.6	**1.10**	41.1	1.17	(4.1)	37.0	**1.06**
35,000	3.9x	2.9x	41.8	**1.19**	44.5	1.27	(4.4)	40.0	**1.14**
35,000	4.2x	3.2x	45.0	**1.29**	47.9	1.37	(4.8)	43.1	**1.23**
35,000	4.5x	3.4x	48.2	**1.38**	51.3	1.47	(5.1)	46.2	**1.32**
35,000	4.8x	3.6x	51.4	**1.47**	54.8	1.56	(5.5)	49.3	**1.41**
35,000	5.1x	3.8x	54.6	**1.56**	58.2	1.66	(5.8)	52.4	**1.50**
35,000	5.4x	4.1x	57.8	**1.65**	61.6	1.76	(6.2)	55.5	**1.58**

(a) Cyclic Steam Stimulation extraction assumes solution natural gas production of 10%.

Source: Company reports; RBC Capital Markets estimates

Natural Gas

Not yet a global commodity like crude oil, but with pricing confined to several localized geographic markets, natural gas is a major commodity by market volumes. Initially more widely used in North America, natural gas consumption is spreading globally as many countries, both industrialized and emerging, diversify their consumption and realize exploration and production opportunities.

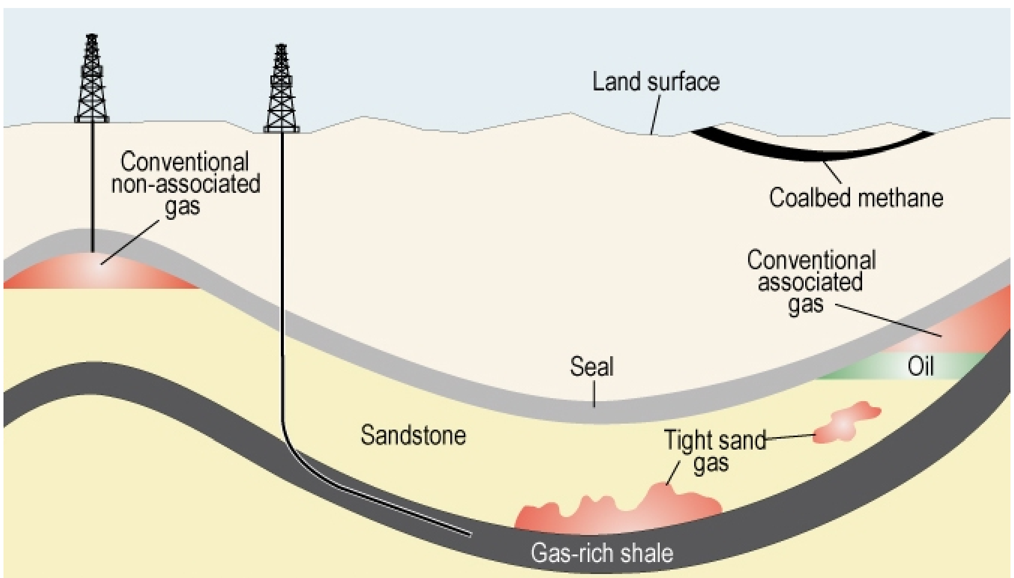
What Is Natural Gas?

Natural gas is a naturally occurring mix of flammable compounds known to chemistry as alcanes. The smallest molecule of the alcane family is methane (CH_4), made of one carbon atom bound to four hydrogen atoms. Methane is the main component of natural gas. Also present in smaller quantities in naturally occurring and produced-at-surface conditions are larger molecules such as ethanes (C_2H_5), butanes, propanes, and their different varieties. Natural gas refers to the mix produced by the well bore, the more methane-concentrated gas stripped out of its larger molecules, and other components naturally present once treated and made ready for shipping into the pipeline network.

There are four typical sources of natural gas (Exhibit 11):

- **Conventional gas accumulations:** Natural gas remains trapped by an overlying impermeable formation, called the seal, when it migrates from its source rock into an overlying sandstone formation. Associated gas refers to natural gas being accumulated in conjunction with oil, while non-associated gas accumulates on its own.[30]
- **Tight sand gas:** Similar to conventional gas reservoirs, natural gas migrates away from its source rock but, rather than accumulating in larger concentrations in stratigraphic traps, it sees its migration ability limited due to the reduced permeability of the rock it encounters and remains diffused over larger areas.[31]
- **Shale Gas:** Natural gas remains trapped in its source rock from which it is unable to migrate.
- **Coalbed Methane (CBM):** Natural gas results from the transformation of organic material in coal.[32]

Exhibit 11: Geologic Nature - Major Sources of Natural Gas



Source: EIA and USGS.

Natural Gas: Conventional Production

Conventional natural gas production typically involves drilling vertically into sandstone and carbonate rock formations.

Conventional natural gas production typically involves drilling vertically into sandstone and carbonate rock formations to release natural gas that has been trapped by a geologic seal. As natural gas is formed by bacteria or high pressures, it tends to migrate upward as long as the rock has sufficient permeability. This migration will continue until the gas encounters rocks with low permeability, called seal rocks, which trap the migrating gas. The focus of conventional gas exploration is finding these traps. This is more difficult than finding vast shale formations, but until recent advancements in hydraulic fracturing and horizontal drilling, conventional gas exploration was more economic than shale exploration. In the United States, conventional gas production has been in decline for several years and RBC estimates that it only represents roughly 30% of U.S. gas production, though it is still the primary source of production for the rest of the world.

Offshore Gulf of Mexico

Natural gas exploration and production in the Gulf of Mexico (GOM) is basically all conventional. Depths cover the spectrum, from only a few thousand feet to over 35,000 feet in the deepwater. The offshore GOM represents around 6% of total U.S. gas production and more than 20% of conventional U.S. gas production[33]. This production will likely be in decline in the near- to mid-term, as permitting issues post the Macondo drilling disaster have substantially restricted new gas drilling in the GOM.

Onshore U.S.

The largest conventional field in the United States is the Hugoton in southwest Kansas, which has approximately 10 tcf–15 tcf of estimated gas in place and accounts for roughly 40% of Kansas' total gas production. The field has been in steady decline since the completion of downspacing in the late 1990s, producing about 380 mmcf/d in 2010 compared to roughly 885 mmcf/d in 2000.[34]

Historically, some of the largest conventional natural gas plays, including the Frio, Yegua, Wilcox and Vicksburg, have been discovered in Texas and Louisiana. However, the conventional onshore Gulf Coast gas plays have been largely drilled up, so there is currently little new conventional activity. While the Permian Basin, located in West Texas and southeastern New Mexico, is traditionally considered an oil field, it also produces substantial volumes of associated gas through conventional methods (around 2.5 bcf/d).[35]

The Rockies have become dominated by CBM and tight sand production, but there are still several large conventional plays. The Madden Field in Wyoming was recently producing around 300 mmcf/d, primarily from the Fort Union, Lance, Cody, and Madison formations at depths of up to 24,000 feet, and has produced over 2 tcf historically[36]. While much of the field is now primarily focused on unconventional development, the Wattenberg Field in Colorado has historically been a significant conventional natural gas producer[37].

In Appalachia, conventional gas is typically produced from the Devonian and Mississippian formations. The largest conventional gas field in Appalachia is the Big Sandy Field near the intersection of Kentucky, Virginia, and West Virginia. The field has yielded over 2.5 tcf to date (expected ultimate recovery over 3 tcf) with current production around 300 mmcf/d. However, nearly all Appalachian activity is currently focused on unconventional shale plays.

The Elk Hills field is the largest gas producing field in California (though it is primarily an oil field), with more than 2.5 tcf produced to date and 500 Bcf in reserves. The field is primarily operated by Occidental Petroleum, and currently produces around 275 mmcf/d (more than 40% of total California gas production).[38]

Canada

Most of Canada's gas production comes from the huge (540,000 square miles) Western Canada Sedimentary Basin (WCSB). The basin produces around 15 bcf/d (more than 12 bcf/d conventionally), representing more than 90% of Canada's total gas production, and has produced more than 170 tcf in conventional gas historically. Estimated remaining conventional reserves are around 140 tcf, but the majority of the most productive areas have already been drilled. As a result, the industry expects WCSB conventional gas production to decline steadily going forward.[39]

Natural Gas: Unconventional Production

Coalbed Methane (CBM)

CBM is natural gas, virtually 100% methane, produced from underground coal seams.

Coalbed Methane is natural gas, virtually 100% methane, produced from underground coal seams. CBM is a North American term and is also referred to as Coal Seam Gas (CSG) in Asia, particularly in Australia. Based on the nature of the process that resulted in its origination, CBM can be biogenic (created through a biological process driven by bacteria fauna) or thermogenic (created through a chemical process driven by high temperature conditions). While conventional natural gas lies chemically unbound with the medium in the pores of a rock or sand formation, CBM is chemically absorbed (stored) in coal. Due to that fundamental difference, coal can hold 6-7 times more gas than conventional gas media. The gas content of a coal seam is generally measured in standard cubic feet per ton (cf/t) or thousand cubic feet per ton (mcf/t). Higher gas content can be more favourable to economic production, although high fracturing and permeability are also very important to productivity of the coals.

CBM production in the U.S. started as an offshoot of coal mining. Gas-laden coals can easily be ignited during coal mining operations. Methane in coal mines historically represented a significant danger of mining activities, potentially resulting in dramatic explosions and costing the lives of numerous miners. The coal industry initially vented gas into the atmosphere, until realizing that volumes were substantial enough to support a separate business line. While CBM production began as early as the 1930s, commercial sales did not become significant until the late 1980s.

In the United States, there are 16 CBM basins currently in various stages of development. Activity is primarily concentrated in nine of those basins. The San Juan Basin and Powder River Basin are the most actively drilled, while the Black Warrior Basin is the longest-producing. The characteristics of each basin vary tremendously, creating significantly different economic parameters.

Shale/Tight Gas Reservoirs

The first commercial natural gas well in the United States was drilled in 1821 in Fredonia, New York and produced from the Devonian-age Dunkirk shale.[40] The nascent E&P industry quickly expanded, targeting shallow shale gas reservoirs throughout the Appalachian and Illinois basins of the north-eastern United States. Development of shale gas, however, soon diminished in favour of more productive conventional reservoirs. Although production from shale has become pervasive in North America over the last decade, it was not until the close of the twentieth century that interest revived when the Barnett Shale came to the fore.

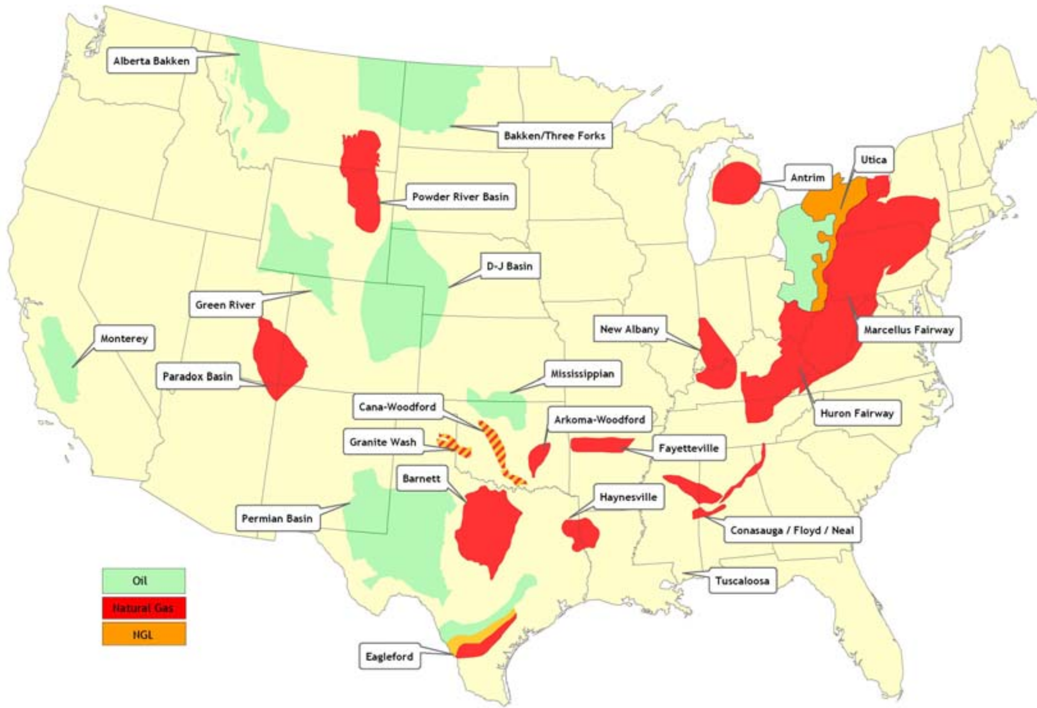
Situated in the Fort Worth basin, the Barnett has led the way as a premier shale gas reservoir in the United States. Since the first vertical wells went into production in 1982, and subsequently with the advent of horizontal drilling around 2000, a new era in U.S. natural gas production was ushered in. Mitchell Energy (later acquired by Devon Energy) drilled more than 3,500 vertical wells in the basin over five decades, bypassing the Barnett, targeting the deeper Boonville Bend Conglomerate and Strawn reservoirs. Noticing well-log analogies between the first Barnett well in Wise County and prolific Appalachian Devonian shales, Mitchell kept experimenting during the 1980-90s, and tried various stimulation techniques. In 2002, Devon tested horizontal drilling, complementing their by-then mature vertical well program. Nearly a decade later, the Barnett Shale averaged more than 6 Bcf/d of natural gas production in 2010, and is currently holding steady above 5 Bcf/d.

It didn't take long for the techniques in the Barnett to be applied elsewhere. In 2003, Southwestern Energy quietly began leasing acreage in northern Arkansas and in 2004, it drilled and completed its first horizontal well in the Fayetteville Shale, a geologic age-equivalent of the Barnett. Other companies quickly followed suit.

Shale Gas Currently Represents the Major Source of North American Natural Gas

Following the results and technical advances of the Barnett, shale gas resources could be unlocked in many other areas in North America. The Fayetteville and Haynesville shales made the riches of the industry while, more recently, the Marcellus and the Utica shales are being targeted (Exhibit 12).

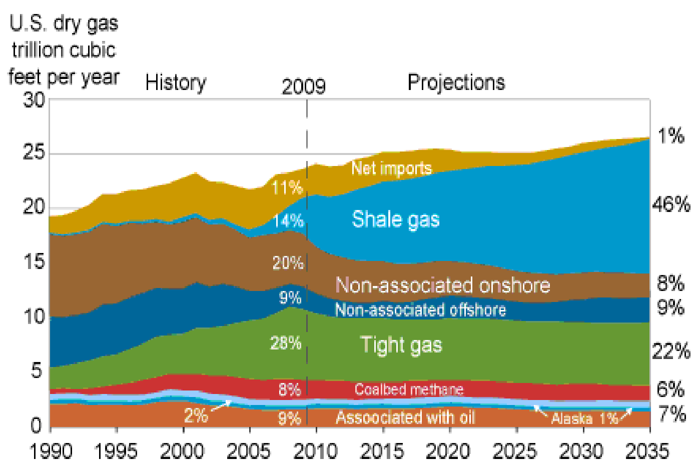
Exhibit 12: U.S. Resource Plays



Source: RBC Capital Markets estimates, EIA and USGS.

According to the EIA Annual Energy Outlook 2011, potential U.S. natural gas resources are 2,543 tcf. Natural gas from shale resources accounts for 862 tcf (34%) of this estimate, or about 100 years of supply, based on 2010 consumption. As shown below, the EIA also expects U.S. shale gas production to expand very significantly going forward (Exhibit 13).

Exhibit 13: U.S. Natural Gas Supply, 1990-2035

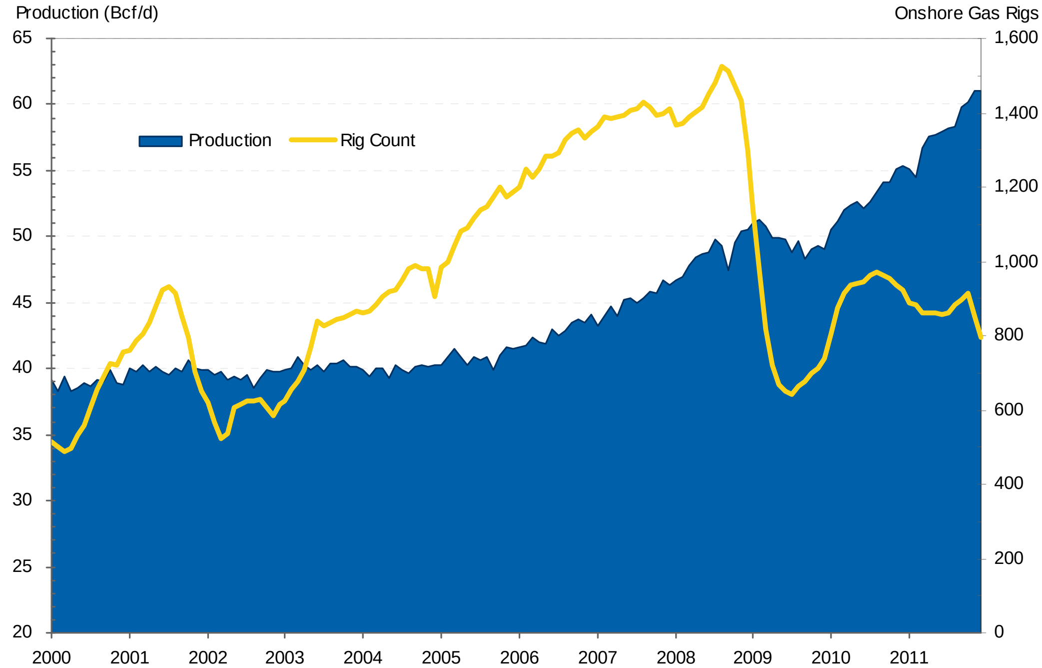


Source: EIA, Annual Energy Outlook 2011

The Unprecedented Shale Gas Growth and Its Impact on North American Gas Pricing

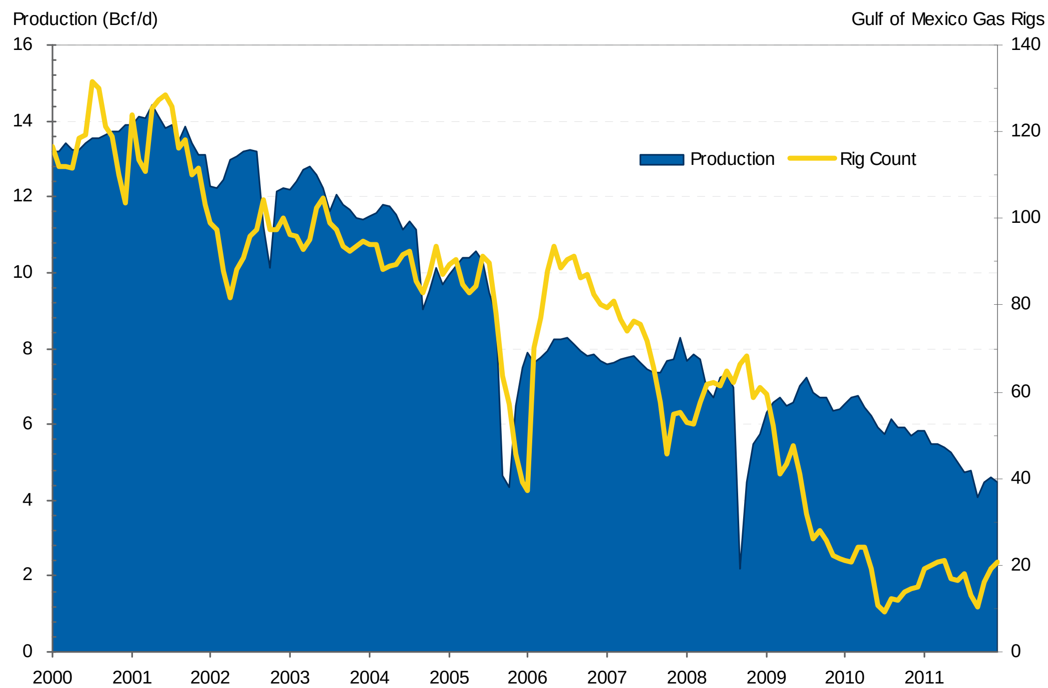
Assisted by the credit crisis and the global recession that followed, the recent growth in U.S. shale gas production reached such unprecedented levels so rapidly that the increase in supply led to a collapse of North American natural gas prices. Despite the obvious impact on pricing and the resulting marginally economical wells, lease expiration timing issues have incentivized the industry to continue drilling to capture leases. Current rig counts remain higher than the number that would suffice to keep production flat (Exhibits 14-15).

Exhibit 14: U.S. Onshore Natural Gas Production and Rig Count



Source: EIA and Baker Hughes

Exhibit 15: U.S. Offshore Natural Gas Production and Rig Count

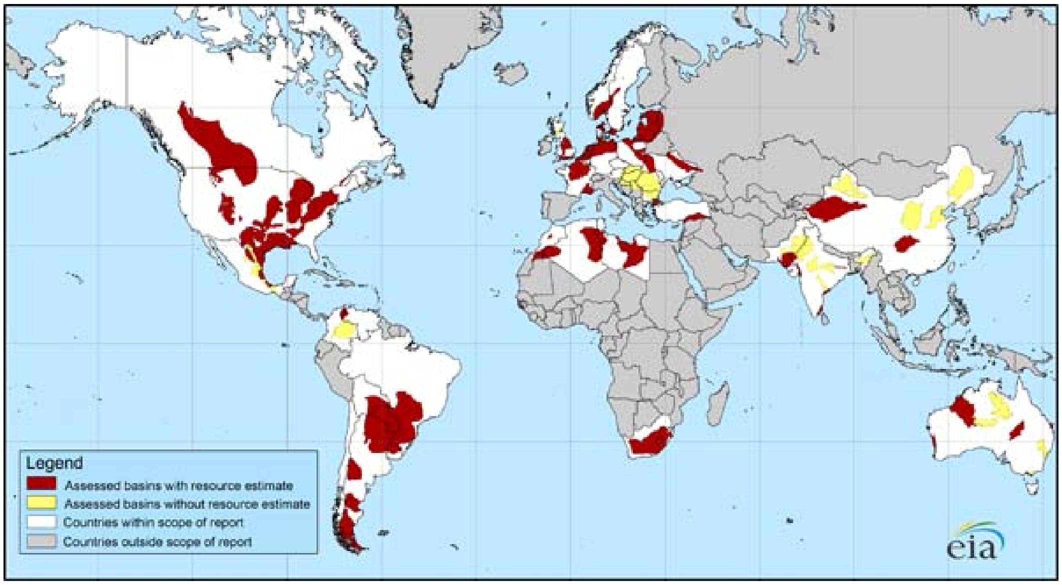


Source: EIA and Baker Hughes

International Shale Gas: The Next Place for Large Growth

Shale gas drilling and completion technology is now being applied in other parts of the world that likely hold immense reserves, previously considered unrecoverable by existing conventional techniques. The UK, Netherlands, France, Germany and especially Poland are European nations thought to hold large amounts of shale gas. China and South Africa also appear to have substantial resources (Exhibit 16). A study by the EIA published in April 2011 identified and assessed global technically recoverable shale gas resources (in the 32 countries examined) equal to 5,760 tcf, excluding the United States.

Exhibit 16: Major Shale Gas Basins – Select Countries



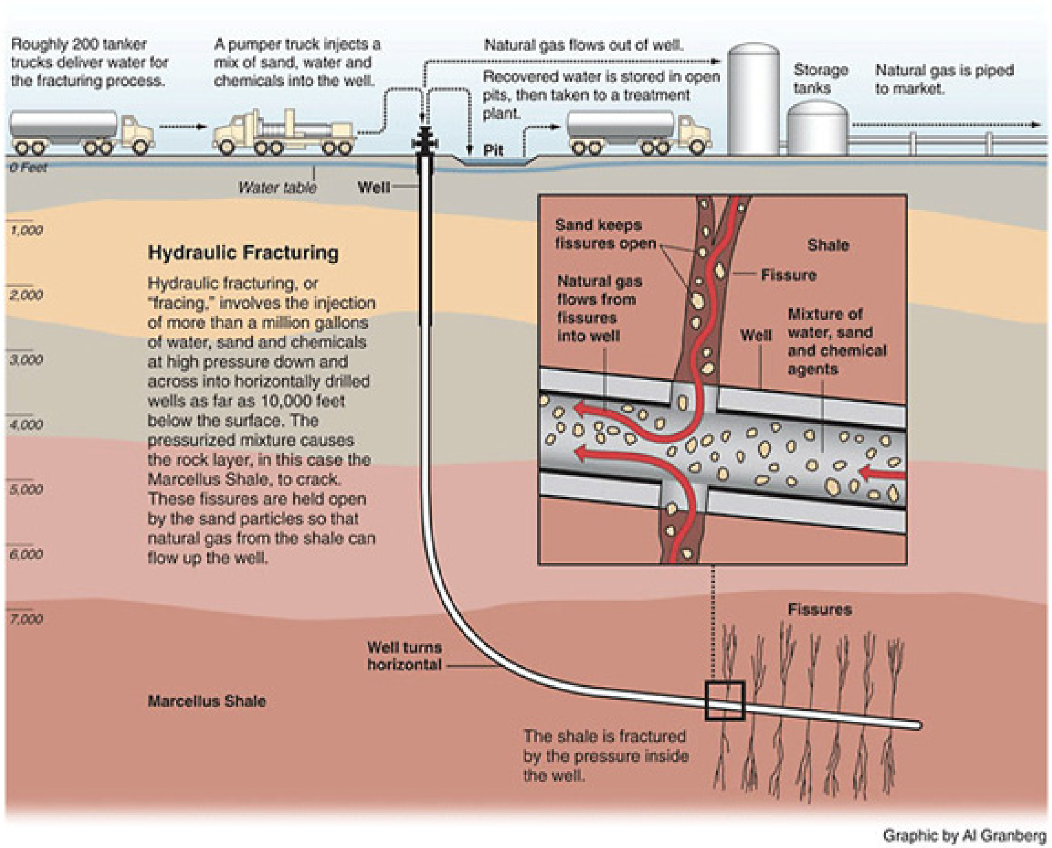
Source: EIA

Shale Gas Drilling

Shale gas drilling techniques differ from conventional techniques due to the low permeability and low porosity characteristics of the shale rock, necessitating two advances over traditional well designs:

- **Directional and Horizontal Drilling.** Shale gas wells need to maximize the surface of the well bore in contact with the formation in order to increase recovery. To achieve this objective, wells penetrate the formation horizontally (as opposed to vertically) to follow its shape. In addition, the azimuth of the well is intended to be perpendicular to the natural fractures of the formation.
- **Hydraulic Fracturing (Fracing).** Once drilled into, the source rock is further fractured to increase the flow of fluids toward the wellbore. Fractures are induced via the injection of pressurized fluid into the well bore. The rock cracks in multiple places around the horizontal portion of the wellbore, with micro pellets of sand or other materials in solution in the water prevent the fractures from closing back in once the fracing job is completed (Exhibit 17).

Exhibit 17: Hydraulic Fracturing Operations



Source: ProPublica

These completion techniques have raised some potential environmental concerns as fracing requires large amounts of fresh water and heavy truck traffic in and around the drilling areas. If mismanaged, fracing fluid spills or leaks could lead to contamination of surrounding areas with hazardous chemicals in fracing water solution.

Natural Gas: Supply and Demand Drivers

Supply

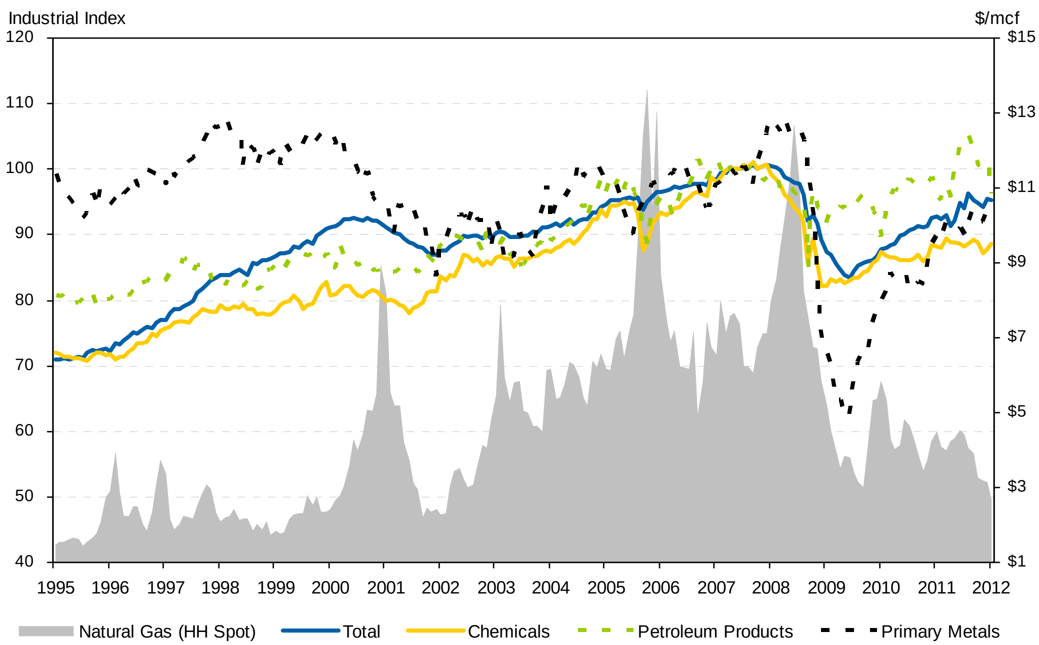
Supply for natural gas is essentially price driven. High prices provide an incentive to explore and drill for new reserves. With a shorter term impact, severe weather also has a seasonal impact on supply. In particular in the Gulf of Mexico (GOM), hurricanes pose a major threat to existing production. Offshore workers are evacuated prior to the storm, shutting in part of the production until crews come back aboard production facilities. This effect has somewhat diminished in recent years, due to the increased automation of production management that requires less offshore staff. In severe cases, hurricanes can damage the platform, further delaying supply from coming back online. In 1992, Hurricane Andrew caused major flows to be re-routed through the North American pipeline system to replace lost supplies.

Demand

Demand is mainly driven by three segments of consumption: (1) industrial consumption, (2) residential consumption, and (3) power generation.

- **Industrial consumption**: This includes all natural gas powered machines, such as ovens in heat processes and heavy equipment to manufacture products. Industrial natural gas usage is highly sensitive to GDP and commodity prices; and over 50% of industrial gas is used by the chemicals, petroleum, and metals industries (Exhibit 18).

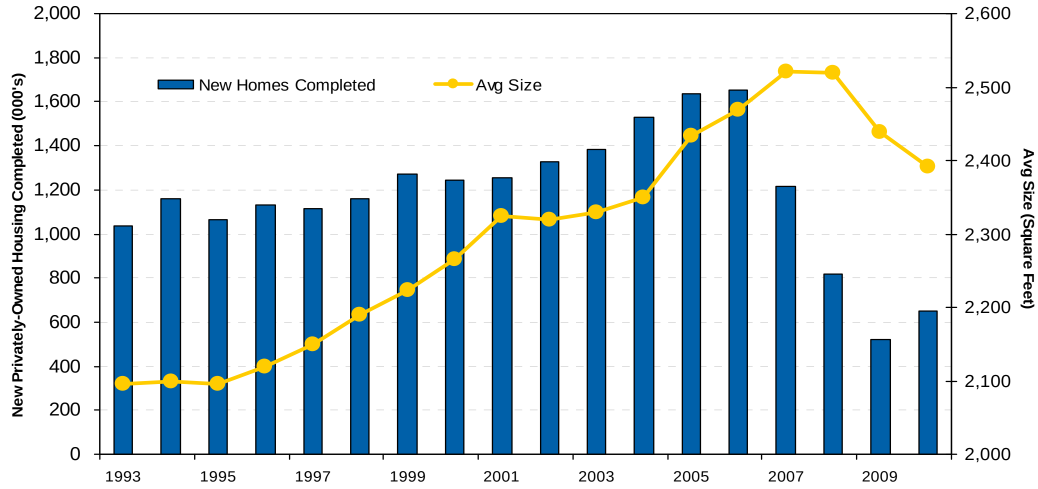
Exhibit 18: U.S. Industrial Natural Gas Usage

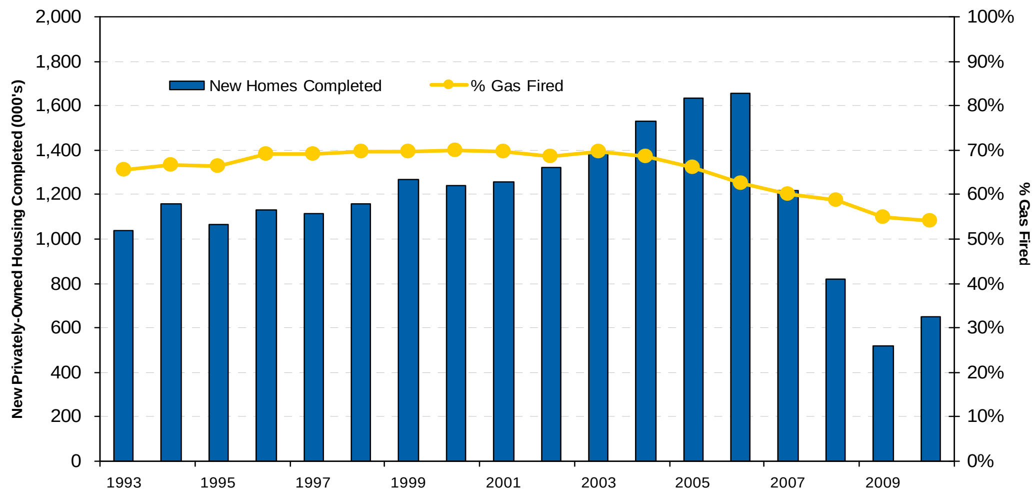


Source: Federal Reserve & Bloomberg

- **Residential consumption**: Natural gas is used for home heating in order to fuel stoves and hot water heating tanks. Despite data showing a shift of populations to warmer climates, residential natural gas consumption remains steady in all U.S. regions. The growing profile of new homes over the past decade, including square footage and higher ceilings, has partly offset gains in efficiency. More recently, new home sizes have tapered off and declined from the boom years (Exhibit 19). Overall, natural gas remains the primary heating fuel but has lost some of its penetration to electric heating systems, while fuel oil usage continues to decline (Exhibit 20).

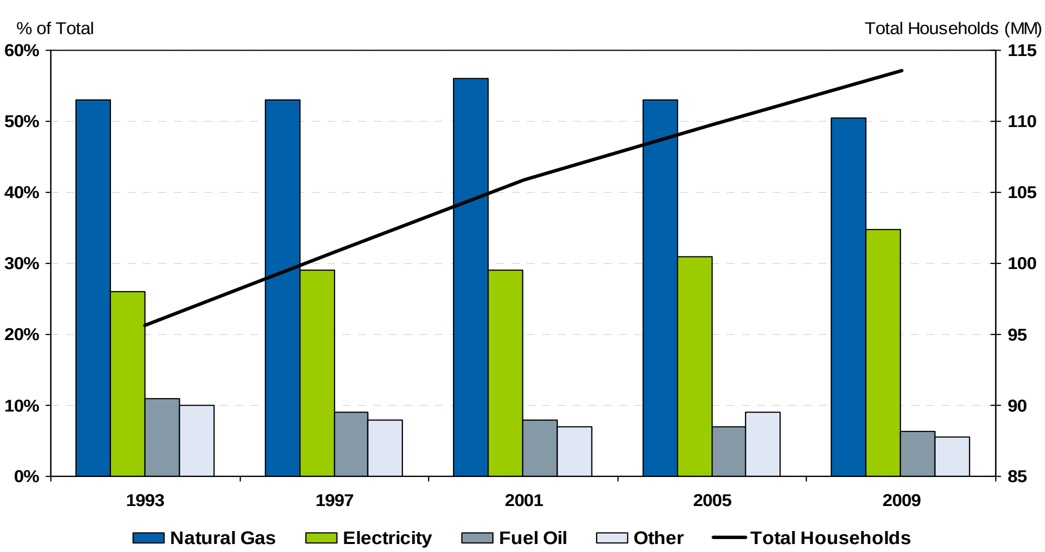
Exhibit 19: U.S. Residential Consumption: New Home Sizes Grow; Gas Remains Fuel of Choice





Source: RBC Capital Markets estimates & U.S. Census Bureau.

Exhibit 20: U.S. Residential Consumption: Primary Space-Heating Fuels

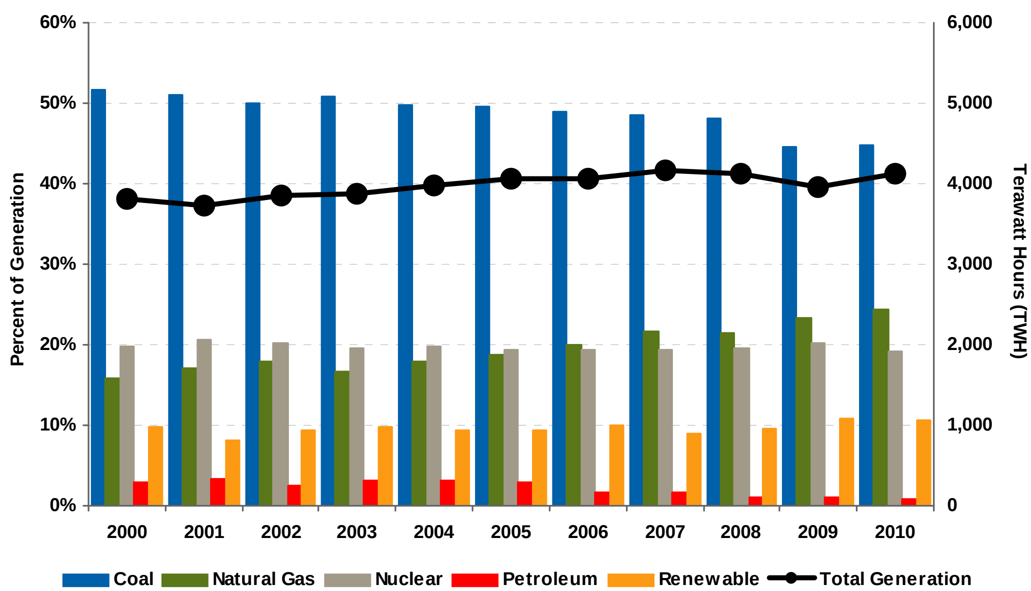


Source: RBC Capital Markets estimates & EIA.

- **Power generation**: Natural gas is also burned in power plants by electric utilities and independent power producers (IPPs) to drive gas-fired turbines and steam-powered generators. Several forces are currently affecting the power generation sector with regards to nuclear, coal, and renewable energy sources (Exhibit 21).
  - The first is U.S. reluctance to the construction of new **nuclear power** plants. The Three Mile Island incident first revealed the reality of the contamination inherent in nuclear energy. Subsequently, the Chernobyl and Fukushima incidents shed light on the technical difficulties of forecasting and preparing for risks at a reasonable cost, and the large scale political and financial liabilities of a major incident. Although nuclear will likely remain part of the energy mix and potentially grow, especially in emerging economies with limited sources to power large-scale growth, many industrialized economies have postponed what was once dubbed "the nuclear renaissance."
  - Secondly, emission standards have placed a lot of scrutiny on the construction of **coal power** plants around the world. Although many projects have been delayed in North America and stopped in Europe, the elusive goal of "clean coal" generation is unlikely to be reached, despite timid progress in CO_2 sequestration efforts.
  - Thirdly, **renewable energy** sources have been growing strongly over the past decade, with capacity reaching roughly 107 GW, although utilization rates remain around 40%. Renewable energy sources require back up power to ensure supply and stability of the electrical network that needs to compensate for the intermittent availability of most renewable sources. Lastly, peak capacity demand requires a fast starting power generation source.

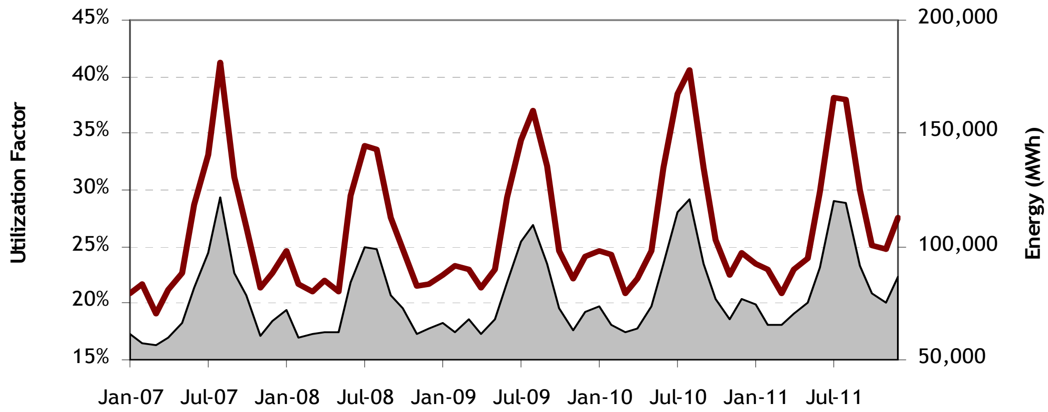
Due to the growing demand for power generation and the lack of alternatives reflective of the challenges discussed above, natural gas remains the fuel of choice to bridge the power generation gap. Recent weakness in the natural gas price has only added to its attractiveness over coal for power generation.

Exhibit 21: Electricity Generation by Source



Source: EIA

Exhibit 22: Natural Gas Generation Utilization



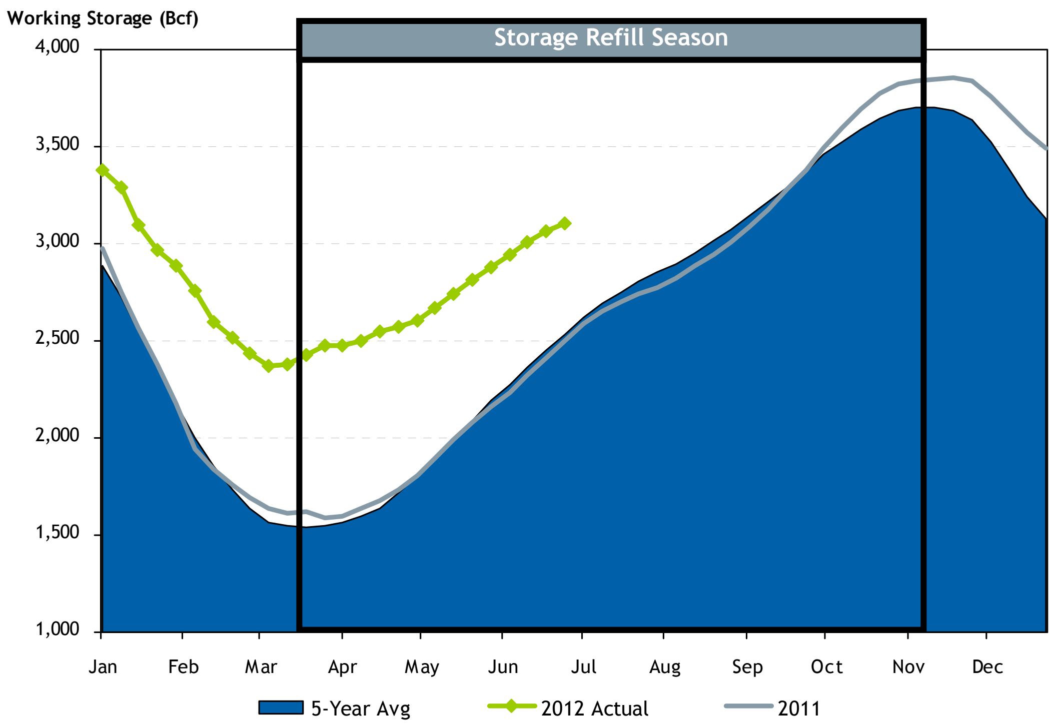
Source: RBC Capital Markets estimates & EIA.

Natural Gas Seasonal Storage

Natural gas utilization peaks in the summer months for electricity generation for cooling and in the winter months for heating. Nonetheless, the winter remains the season with the highest demand. Because supply cannot be turned on and off seasonally but rather, it is driven by E&P exploration programs, large storage facilities are used to act as a buffer in order to smooth out the seasonal consumption patterns (Exhibit 23).

Natural gas utilization peaks in the summer months for electricity generation and in the winter months for heating.

Exhibit 23: U.S. Natural Gas Storage Cycles, Inventory as of July 2012



Source: RBC Capital Markets estimates & EIA.

Natural gas is held in storage in North America over the different seasons. It is pumped in during the low consumption summer and pumped out during the winter. Three types of underground facilities are mainly used:

- **Depleted reservoirs.** Depleted reservoirs in oil and gas fields are the most commonly used storage facilities, since they are widely available, often close to consumption centres and offer existing available infrastructure and connection to an existing pipeline network.
- **Aquifers**. Water bearing sedimentary rock formations overlaid by impermeable cap rocks are often suitable to store natural gas.
- **Salt cavern formations**. Salt dome formations in the U.S. Gulf Coast states have been used for natural gas storage because they offer appealing high withdrawal and injection rates relative to their working gas capacity.

Over the past decade, storage activities have shifted away from seasonal inventory management toward market-oriented arbitrage opportunities. This was particularly facilitated by Federal Energy Regulatory Commission ("FERC") Order 636 that required pipeline companies to operate facilities on an open access basis, making them available for lease by third party players.

LNG: The New Kid on the Block

Liquefied Natural Gas (LNG) is natural gas that has been treated and subsequently converted into a liquid state by cooling it to a temperature lower than -160^{o}C (-269^{o}F) in a liquefaction plant. LNG must be stored and transported at or near this temperature and at a pressure of 8 bar. This is accomplished in an insulated, pressurised, double tank system, similar in principle to a thermos flask. LNG is approximately 1/600th the volume of natural gas at atmospheric conditions and has an energy density that is approximately 60% that of diesel and 70% that of gasoline. LNG is converted back into a gas state at a regasification plant located at terminals connected to local supply systems associated with regional markets.

Traditional suppliers of LNG include Australia, Algeria, Indonesia, Malaysia, Nigeria and Qatar, while East Asia and Europe have been consumers of LNG for several decades. Global demand for LNG is increasingly strong, driven by firm underlying demand. Demand in the U.S. has always been marginal, with the country historically thought of as an LNG importer despite very stringent requirements to build gasification facilities which made obtaining new permits a lengthy and uncertain process. Faced with the glut of natural gas from U.S. shale production, however, the idea of LNG exports from the lower 48 states is gaining momentum, although political barriers remain.

North American Natural Gas: Benchmark Prices

Natural gas is generally more expensive and difficult to transport than liquid hydrocarbons. Within North America, natural gas is generally only transported by pipelines, which are very expensive to build over long distances. As a result, natural gas benchmark prices are typically determined by the supply and demand dynamics of local markets near where the gas is produced. Gas produced near population centres and premium electricity markets, such as the Northeast United States, generally receives a higher price due to strong regional demand. However, gas produced in areas with low populations relative to the amount of gas produced or highly seasonal demand, such as the Rockies and Canada, may receive a lower price due to the supply/demand imbalance. Natural gas prices are generally quoted as USD per million British thermal unit (mmBtu). Conventionally, one thousand cubic feet (1 mcf) of natural gas is equivalent to 1.03 mmBtu. However, one mcf of gas produced in different regions often contains varying energy content, and may therefore receive pricing that is slightly different than the benchmark per Btu.

Seasonality

Natural gas is one of the more seasonal commodities, as a result of being used extensively for heating in the winter and to generate electricity for cooling in the summer.

Natural gas is one of the more seasonal commodities, due to its extensive use for heating in the winter and for generating electricity for cooling in the summer. Natural gas prices tend to be strongest during the winter months, due to very high residential and commercial heating demand. The residential and commercial share of natural gas consumption (which largely represents heating use) typically bottoms at around 15% during the summer, and peaks at around 55% during the winter. Gas prices also tend to be strong during the summer, when the share of natural gas consumption attributable to electricity generation (which largely represents cooling use) tends to peak around 55%, compared to a bottom of around 20% in the winter.[41] Prices tend to be weaker in the shoulder seasons as both heating and electricity demand is typically low during the spring and fall months. Additionally, natural gas prices can experience abrupt spikes as a result of an active hurricane season in the Gulf of Mexico (July-October) as the region accounts for a decent portion (around 10%) of U.S. gas production.

Henry Hub: The Key U.S. Gas Benchmark

Henry Hub was chosen as the benchmark spot natural gas for the New York Mercantile Exchange's (NYMEX) futures contract in 1989. The actual delivery location of the Henry Hub contract is a point on the natural gas pipeline system (owned by Sabine Pipe) in Erath, Louisiana. The hub provides access to many of the major gas markets (Midwest, Northeast, Southeast and Gulf Coast) in the United States through nine interstate pipelines, which is the primary reason for the benchmark's popularity.[42]

Other Important Natural Gas Benchmarks

While Henry Hub is typically used as the proxy for the entire United States gas market, there are numerous regional benchmarks. Some notable North American benchmarks that are tied to major gas producing regions are highlighted below. Please refer to Exhibits 24-25 for North American natural gas market center hubs and select historical price differentials to the Henry Hub benchmark.

Appalachia: Appalachian gas has historically traded at a premium to Henry Hub, mainly due to its proximity to premium Northeast markets with very high relative gas demand and abnormally large population centres relative to the amount of gas produced. The influx of natural gas produced from the Marcellus Shale has also done little to narrow the differential. There are two major Appalachian benchmarks, the Dominion and Leidy Hubs. The Dominion Hub is the most active of the market centres operating in the Northeast, with interconnections to more than 15 major pipelines, and access to substantial storage facilities. The Leidy Hub is a storage facility in Clinton County, Pennsylvania, where many interstate pipelines traverse the general area (with transportation to the Southeast, Texas, Northeast and the West Coast).[43]

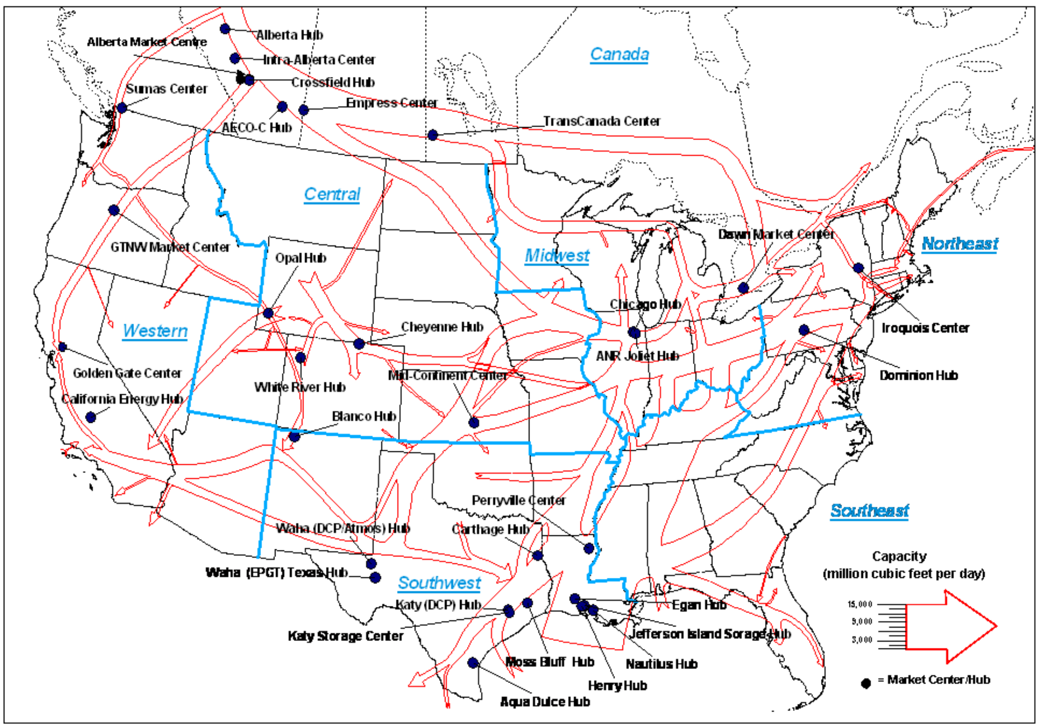
Colorado Interstate Gas (CIG): The Colorado Interstate Gas benchmark is generally considered the best proxy for the Rockies gas market. The benchmark has fluctuated wildly on a historical basis but has often traded at a relatively steep discount to Henry Hub due to the sparse population density and relatively low power demands of the local markets. While the CIG pipeline system allows transportation to Wyoming, Utah, Colorado, Kansas, Oklahoma, Texas and California, there are few major population centers nearby that can receive the natural gas.[44]

AECO Hub: The AECO Hub is a gas sales location physically located in Suffield Alberta, and is generally used as a proxy for the entire Canadian market. Essentially all of the natural gas sold at the AECO hub is produced in the Western Canada Sedimentary Basin (WCSB) which accounts for 95% of Canada's gas production. AECO natural gas tends to trade at a discount (or "basis") to Henry Hub, which can vary wildly as a result of a multitude of factors which include Alberta supply and demand levels, but has historically averaged $0.60 - $0.80/mcf.[45]

NGPL Mid-Con: The NGPL Mid-Con benchmark is a good proxy for the gas market in the U.S. Mid-Continent region. This market tends to trade similarly to the CIG market, though Mid-Con typically trades at a smaller discount to Henry Hub reflecting better access to premium markets in the south.[46]

Waha: The Waha benchmark represents the gas market in West Texas, which is primarily supplied by gas produced in the Permian Basin. Because there is limited gas demand in West Texas due to the low population density, Waha had historically traded at a substantial discount to Henry Hub. However, this discount has narrowed as of late due to increased capacity for transport out of West Texas (to the Midwest, East Texas, southern Louisiana and the West Coast). The discount to Henry Hub tends to shrink during the summer months as power use for cooling increases in Texas, and it increases during the winter on lower power demand in the South relative to the Northeast.[47]

Exhibit 24: Natural Gas Market Center Hubs



Source: EIA

Exhibit 25: Average Historical Natural Gas Price Differentials - Select Hubs

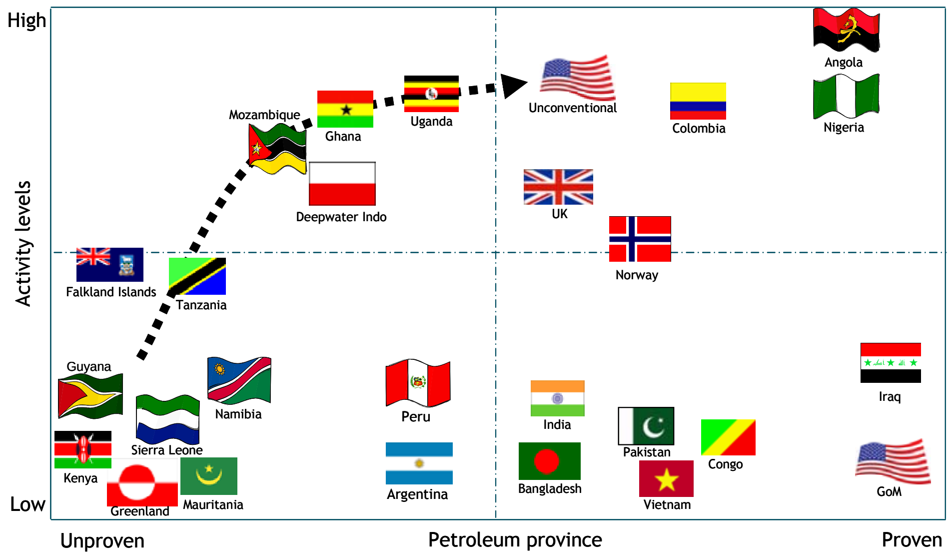
	Average Henry Hub Natural Gas Differential						
Benchmark	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**1H12**
Henry Hub Gas	**$6.73**	**$6.97**	**$8.89**	**$3.94**	**$4.37**	**$4.00**	**$2.36**
Appalachian Gas	$0.36	$0.54	$0.75	$0.59	$0.50	$0.37	$0.14
Waha Gas	($0.70)	($0.54)	($1.19)	($0.42)	($0.16)	($0.08)	($0.05)
Mid-Con Gas	($0.77)	($0.75)	($1.69)	($0.62)	($0.21)	($0.10)	($0.09)
AECO Gas	($0.97)	($0.96)	($1.08)	($0.44)	($0.50)	($0.33)	($0.36)
Rockies Gas	($1.31)	($2.91)	($2.29)	($0.75)	($0.43)	($0.16)	($0.08)

Source: Bloomberg

International E&P - The Exceptions

International E&P provides access to less mature and, at times, frontier basins, such as French Guiana and Greenland, where there is the potential to make significant discoveries or access under-exploited opportunities as the political or security situation becomes more conducive to foreign involvement. This allows often relatively small companies to build extensive acreage positions leading to rapid growth and success. International E&P companies take a relatively open-minded view on geographies, and have opened up a number of new basins / provinces as shown in Exhibit 26 below.

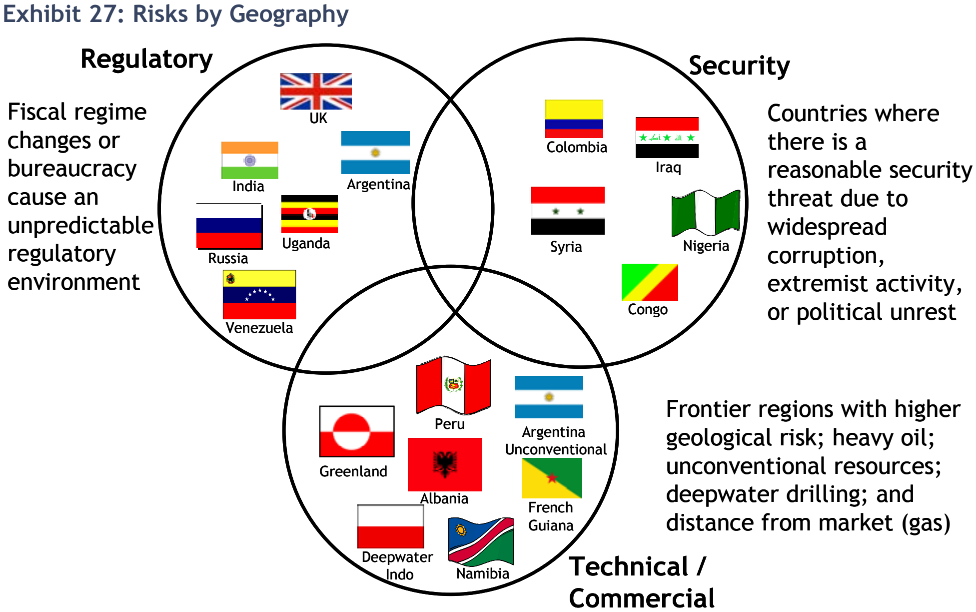
Exhibit 26: Hot E&P Geographies



Source: RBC Capital Markets

This global access does, however, expose International E&Ps to a variety of risks, including (1) technical/commercial, (2) security, and (3) political / regulatory risks. Exhibit 27 below plots some of the key geographies in terms of these risks. Note that countries with regulatory risk include the UK where, in early 2011, the upstream marginal tax rate was increased from 50% to 62%.

Exhibit 27: Risks by Geography



Source: RBC Capital Markets

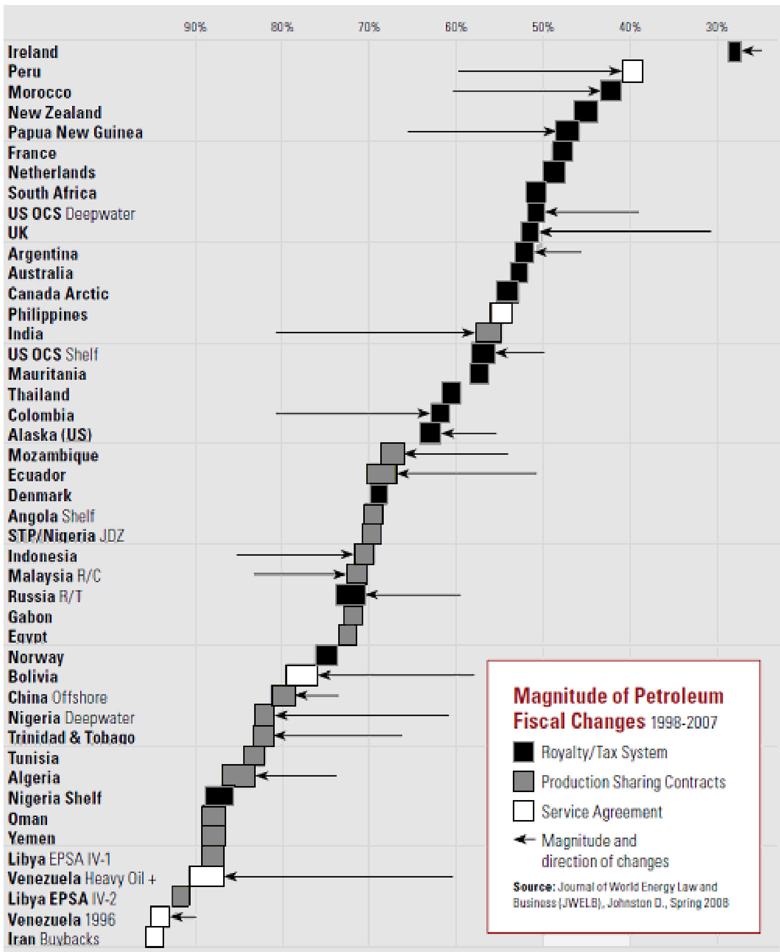
Fiscal Terms

Oil and gas is of strategic importance to nations, particularly with regards to the revenues that accompany development. In order to begin oil and gas exploration and development, a company requires a contract granted either by the government or its National Oil Company (NOC) to exploit the resources. Rates and systems vary across the world and, to put it simply, the most attractive provinces have the harshest terms.

For prolific geographies, demand for licences is high and the entry costs (signature bonuses) and fiscal terms are often harsh. The opposite is true for countries with limited or unknown oil reserves.

For prolific geographies, demand for licences is high and the entry costs (signature bonuses) and fiscal terms are often harsh. The opposite is true for countries with limited or unknown oil reserves. In a bid to attract investment, fiscal terms are eased (e.g. Ireland's fiscal take of 30% compared to Norway at 78% or Indonesia at 85%). Fiscal regimes can also be improved to attract investment to mature or increasingly overlooked regions, such as India and Colombia, where the terms and opportunities are (now) both attractive. Exhibit 28 presents the magnitude and direction of fiscal changes from 1998 to 2007. A move to the left represents an increase in the government take and, therefore, increased regulatory risk. Note that these tax rates can be changed by the government.

Exhibit 28: Magnitude of Petroleum Fiscal Changes



Source: Journal of World Energy Law and Business

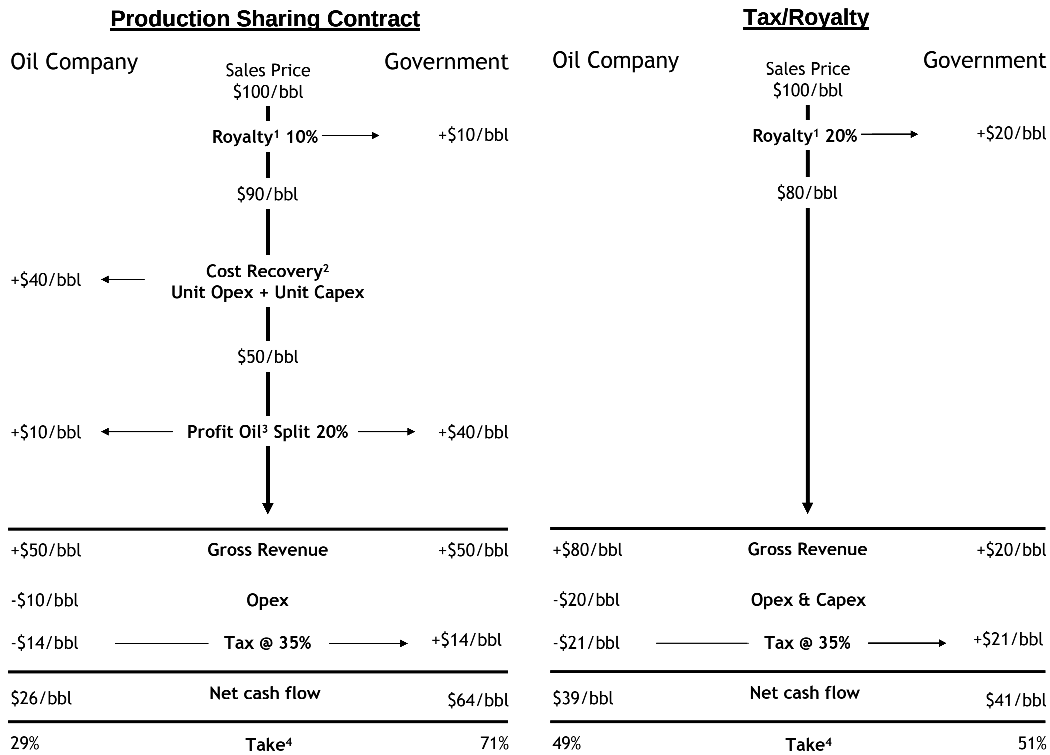
The type of fiscal agreement can vary between and within countries and depends on many factors, including the maturity of the industry, the potential for investment, and the political regime. In general, the fiscal agreements can be divided into two broad types: 1) tax and royalty regimes or 2) Production Sharing Agreements / Contracts (PSAs/PSCs) (Exhibit 29). In some countries, government back-in rights allow the government to avoid funding exploration while retaining an option to take a stake in any commercial development.

Concession (Tax & Royalty): The oil & gas company is granted rights to exploration and development, taking on the full risk and costs and generally holding title for all resources found. The production and sale of hydrocarbons may be subsequently subject to royalty payments (percentage of revenue) before enduring profit-related taxes – generally corporate tax and industry specific taxes.

In a PSC, the resource is owned by the state and the foreign company is brought in to explore and develop the resource.

PSC: In a PSC, the resource is owned by the state and the foreign company is brought in to explore and develop the resource. The contractor takes the exploration and development risk and is entitled to a specified share of production to recover its costs and, thereafter, a portion of the profit. Ownership of the underlying resource is retained by the government in most cases. “Cost oil” is capped at a fixed level of production and the remaining output “profit oil” is shared depending on variables such as the project’s rate of return, cumulative production, output levels, etc. Given this blend of formulas, under a PSC, the contractor’s share of production generally decreases with increasing prices and cumulative production levels (known as the “R” factor). It is important to note that a PSC is a legal agreement and, therefore, is rarely ever changed.

Exhibit 29: PSC vs. Concession Example



[1] Royalties can vary on production and can include windfall tax elements arising on higher oil prices.
[2] Cost recovery varies according to the stage of project and fiscal terms. In the early stages of a project, cost recovery can be up to 100%, covering high up-front costs, then trending toward 0% as the project reaches maturity and profitability increases.
[3] Profit oil split can vary with production or investment levels.
[4] Take calculation based on net cash flows

Source: RBC Capital Markets

Pricing

Oil pricing for International E&P companies is very much a global matter, with many of the companies' sales prices indexed to Brent or, to a lesser extent, WTI. However, prices vary with quality, volumes, and export costs. Depending on the country, prices can be subject to government regulation and price caps (e.g. Argentina). Oil and gas pricing can also be impacted by domestic market obligations (Indonesia/Malaysia) or variations in domestic and export prices (Russia/Kurdistan).

Gas prices vary regionally and are a function of the local demand and supply dynamics. As such, regional markets have an impact on prices, development schedules and gas sales volumes. India, Malaysia, Bangladesh and Pakistan all have low fixed gas prices, whereas in Europe, Indonesia and Thailand, gas prices are linked to oil and are currently much higher. Increasingly in Africa and Asia, gas prices have been driven higher by rising demand for exports, which has opened up the LNG industry in these regions, improving supply for areas short on gas. Gas sales contracts are typically required ahead of development activity and will determine the pricing mechanism over the duration of the field life.

Midstream Sector

In the midstream sector, raw crude oil & natural gas that is produced and developed from the upstream sector is gathered, processed, transported and marketed to the downstream sector.

In the midstream sector, raw crude oil & natural gas that is produced and developed from the upstream sector is gathered, processed, transported and marketed to the downstream sector, which consists of end-use customers, wholesalers and local distributors across North America. Midstream facilities can include gas processing, liquids extraction, gas and liquids storage, and transportation assets. Liquids can refer to crude oil or natural gas liquids (NGLs), such as ethane (C_2), propane (C_3), butane (C_4) and condensate/pentanes (C_5). Condensate is particularly important in Alberta, where it is widely used to dilute oil sands bitumen production, so that it can flow through the pipeline system.

Natural Gas Gathering and Processing

Raw natural gas produced from the upstream sector is typically composed of methane (commonly referred to as "natural gas") and NGLs. The gas processing plants take "wet" gas and remove the heavier liquids components (NGLs) as well as other contaminants to create marketable "dry" gas, which will only then meet the gas composition restrictions of major transportation pipelines. Although a by-product in the process, the extracted NGL stream that contains ethane, propane, butane, and condensate is of significant value, and this mixture is subsequently sent to fractionators to be separated into marketable products. Gas producers targeting "liquids-rich" gas are looking for "wet" gas streams that have a significant amount of NGLs entrained. Canadian gas processing economics in the field are generally on a fee-for-service basis. Large extraction plants (also called "straddle plants") on the main export line often operate under economics that depend on the price of the extracted liquids relative to its equivalent value if left in the original gas. The difference between the price of the extracted liquids and its price of methane (i.e., natural gas) is called the "frac spread".

Fractionation, Transportation, and Storage

Midstream companies also own and operate infrastructure, including fractionation plants, storage facilities, and rail and truck loading/offloading facilities. The raw NGL-mixed stream from gas processing plants is sent via NGL pipelines or trucks to fractionation facilities that separate the liquids mixture into marketable products (ethane, propane, butane and condensate) that can be used as feedstock for petrochemical plants and refineries, or as heating fuels. These marketable products are transported by various methods to major NGL marketing hubs in North America (e.g., Edmonton, AB; Conway, KS; Mont Belvieu, TX). When supply outweighs demand (often seasonally driven, particularly in the case of propane), gas, oil and NGLs can be stored in either above-ground or underground storage facilities, which provide a ready supply to meet seasonal and operational requirements.

Pipelines

Unlike refined petroleum products, natural gas is delivered directly to homes and businesses through an extensive network of smaller diameter distribution pipelines.

Pipelines are the primary method of transporting natural gas and liquids over long distances from producing regions to end users, such as refineries, which convert crude oil feedstock into end-products such as gasoline, diesel and other petrochemicals. Gas pipelines are used to transport natural gas from wells to processing plants and distribution systems. Unlike refined petroleum products, natural gas is delivered directly to homes and businesses through an extensive network of smaller diameter distribution pipelines. Please refer to Exhibit 30 for diagrams detailing both crude oil & natural gas pipeline delivery networks.

Liquids Pipelines

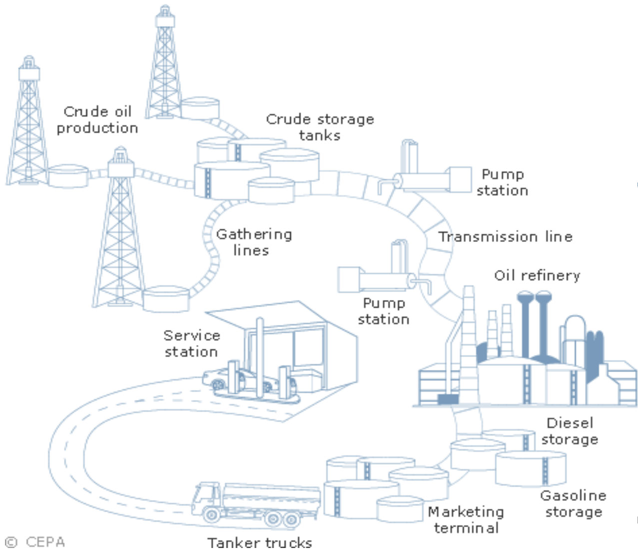
Producing oil fields either have a network of small-diameter gathering lines or use trucks to move produced oil from the wells to central facilities, where larger-diameter feeder pipelines transport the crude oil to nearby refineries and to long-haul pipelines. Through these transmission lines, crude oil is transported to more distant refineries, which use various processes to convert crude oil into refined petroleum products such as gasoline. In addition, liquids transmission lines carry other types of liquids in batches, including refined petroleum products and NGLs.

Gas Pipelines

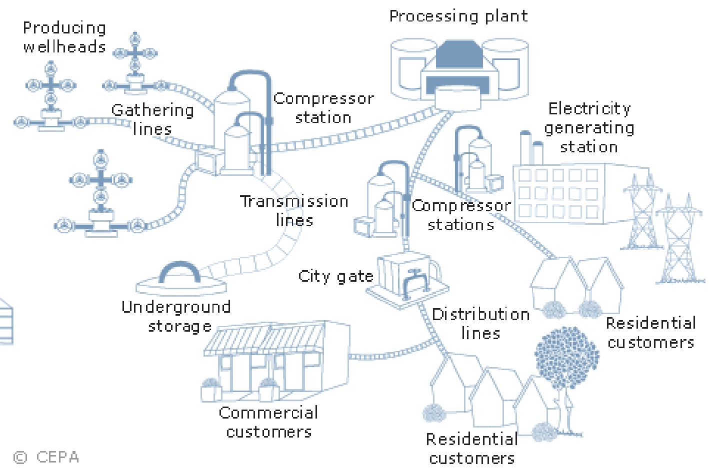
Natural gas producing fields typically have a network of small-diameter gathering lines to move raw natural gas from the producing well to a gas processing facility, which removes water and other components (including NGLs) from the raw gas stream. The "purified" natural gas is then compressed prior to moving into gas transmission pipelines. Compressors placed along the gas transmission pipeline increase the pressure of gas, thereby moving it to its destination, where local distribution companies or gas utilities reduce the pressure for local delivery through smaller distribution pipelines to industrial, commercial and residential customers.

Exhibit 30: Pipeline Delivery Networks

Crude Oil Delivery Network



Natural Gas Delivery Network



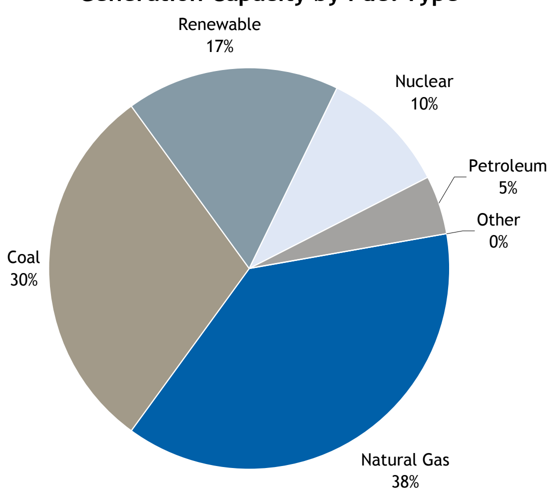
Source: CEPA

Power Generation

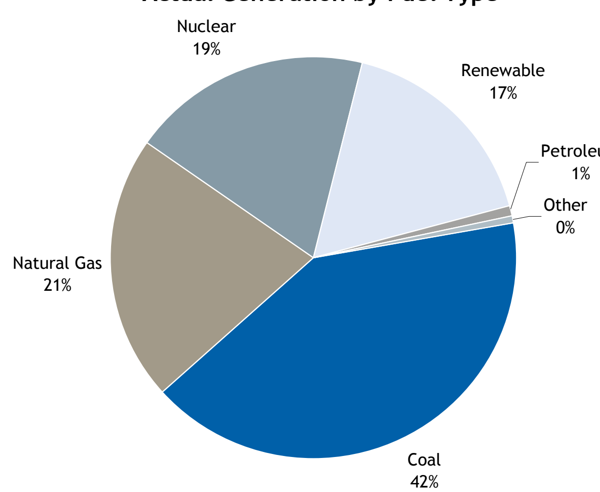
The power sector consists of independent power producers (IPPs) that own unregulated power generation facilities and integrated regulated utilities that own power generation plants along with electric transmission and distribution systems. Power is generated from various sources including coal, natural gas, nuclear, hydro, wind, solar and biomass. As shown in Exhibit 31, the majority of generation capacity and associated power generation comes from coal and natural gas.

Exhibit 31: North American Power Generation (2011)

Generation Capacity by Fuel Type



Actual Generation by Fuel Type



Source: EIA, NERC, CEA, RBC Capital Markets

RBC Capital Markets®

Coal: In 2011, 42% of electricity was produced from coal-fired power plants although only 30% of North American capacity consists of coal-fired facilities. The disproportionate amount of power generation compared to capacity is partly due to the large domestic supply of coal and the low variable cost, making it an economic form of baseload generation. However, the proportion of power from coal-fired power plants is expected to decline over time due to increasing environmental regulations on both sides of the border to deal with emissions (e.g., carbon dioxide, sulphur dioxide, nitrogen oxides). Power is generated from the combustion of coal heating boiler-water, which is channelled to drive a turbine that produces electricity.

Natural Gas: Power from natural gas contributed 21% of total supply in 2011, which is well below the proportion of generation capacity at 38%. However, the proportion of power generation from natural gas is expected to grow over time as a replacement for coal-fired capacity that is expected to be decommissioned due to increasingly stringent environmental regulations. The technology to convert natural gas to power offers a range of efficiency and flexibility. Simple-cycle combustion turbines (often called peakers) can quickly start-up (i.e., some within five minutes) to respond to periods of high demand/prices although these units are less efficient with higher variable costs. Combined-cycle gas turbines (CCGTs) are more efficient with lower variable costs and emissions levels, and are better suited to markets where gas-fired generation is expected to run on a more consistent basis.

Nuclear: Nuclear power generation has a high fixed cost, but low variable cost. Emissions are minimal, which has been an attraction as governments try to achieve lower carbon emissions, although spent nuclear fuel must be handled and stored properly. Power is generated when a nuclear reaction heats boiler-water to produce high-pressure steam, which is channelled to drive a turbine that produces electricity.

Wind: Wind is a renewable resource that is both clean and free. Although wind possesses virtually no variable costs, facility sizes are smaller, the power output is variable and wind resources are often located away from existing transmission grids, which necessitates costlier transmission connections. Further, the variability of wind requires the availability of other generation sources that can provide a back-up supply of power (e.g., natural gas-fired peaking plants, reservoir hydro).

Hydro: Hydro provides over 60% of generation in Canada, but less than 10% in the U.S., partly due to the availability of suitable water resources. Power is generated by water, usually associated with a significant elevation drop, passing through a turbine that generates electricity. Two of the predominant forms of hydro power production are reservoir-based and run-of-river. Reservoir-based hydro employs a dam that can be used to both create an elevation drop and/or to hold back water until peak power needs. On the other hand, run-of-river hydro diverts water from the river to the turbine after which the water re-joins the river.

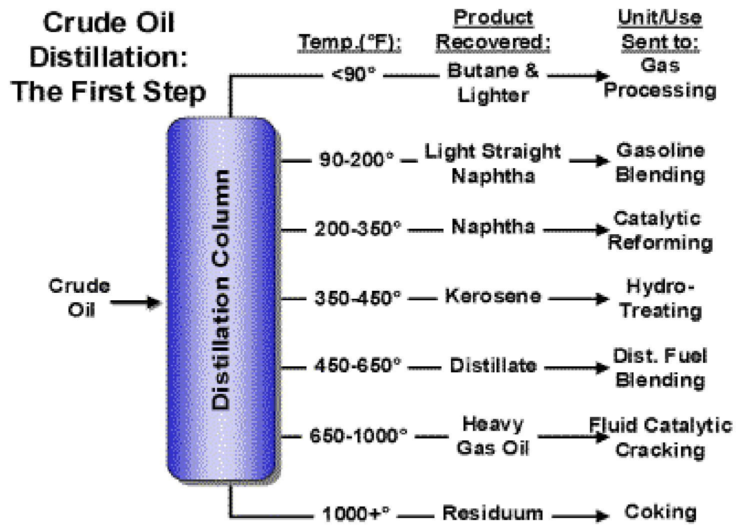
Downstream

The downstream sector encompasses the refining and product marketing portions of the petroleum value chain. Both integrated oil companies and independent refiners are involved in downstream activities.

Refining

Refining is a simple distillation process whereby crude oil is heated and placed in a distillation column resulting in various products (fractions) boiling off and being recovered at different temperatures. "Top of the barrel" or lighter products such as liquid petroleum gas (LPG), naphtha, and gasoline are recovered at the lowest temperatures. Middle distillates such as jet fuel, kerosene, distillate (heating oil and diesel fuel) are burned off at a higher temperature than the lighter products. "Bottom of the barrel" or heavy products (residual fuel oil) are recovered at the highest temperatures. Following the distillation process, most refineries reprocess the heavier fractions into lighter products to maximize economic output. The processes beyond distillation include reforming, hydrocracking, catalytic cracking, coking, alkylation and blending (Exhibit 32).

Exhibit 32: Simple Crude Oil Distillation Process



Source: EIA

Refining margins (also known as "**crack spreads**") are the differentials between the input price (crude oil) and the output price of petroleum products created from the refining process. For example, the "3-2-1" crack spread refers to the margin a refiner receives from processing 3 barrels of crude oil into 2 barrels of gasoline + 1 barrel of distillate.

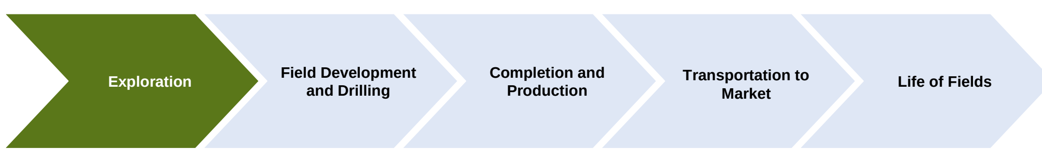
The U.S. refining market (with a total capacity of approximately 17 mmbbl/d) is divided into 5 regions (known as PADDs), with approximately 50% of that operating capacity located in the Gulf Coast region (PADD 3).[48] U.S. refiner profitability is affected primarily by relative demand for light products (gasoline + distillate + jet fuel) and supply factors such as spare capacity in the market, imports, crude differentials (including light/heavy and Brent/WTI). Within certain operational constraints, refiners adjust their crude slates and processing runs to derive the most economic profit from each of their assets. Complex refiners, which have the ability to process heavier and more sour crude oils, can take advantage of wide light/heavy differentials (when they occur) to improve profitability.

In the United States, overall demand for gasoline is generally higher during what is known as the driving season (late May to early autumn) and refineries run at higher utilization rates to meet this demand. Refiners routinely perform maintenance activities between early autumn and late winter as demand falls.

Oilfield Services

Oilfield Service companies provide the equipment and services to help producers explore, extract, and transport oil and natural gas. The services these companies provide can be mapped against the upstream value chain, to better understand how oilfield services companies add value to the oil and gas production process.

Upstream Stage	Exploration and Production sector role	Oilfield Services sector role	Duration
Exploration	Locate underground rock formations that may contain hydrocarbons, delineate the scale of the resource, and reach agreements with owners of surface and mineral rights in the area.	Acquire seismic data (land, transition zones and offshore) using dedicated equipment and then process them to de-risk exploration drilling operations. Perform exploration drilling (coring, logging) to help locate and delineate the resource.	6 months to 5 years
Field Development & Drilling	If field economics justify, invest in full field development. Define the well architecture and the development scheme that contractors will follow.	Drill for resources (onshore, offshore, subsea, horizontal, directional). Operate coiled tubing rigs. Manufacture and deliver drilling fluids. Provide supporting equipment (e.g. rentals). Engineering, Procurement and Construction (EPC) firms develop infrastructure (onshore, offshore, subsea).	3 months to 4 years
Completion & Production	Extract as much hydrocarbon as possible without damaging reservoir properties in a safe and cost effective manner.	Case and cement the well, stimulate the well to increase the productivity of the well, and perform work over operations.	3 months to 3 years
Transportation to Market	Oversee the transportation of the produced hydrocarbons from the well site to markets.	Build and operate natural gas compression and processing equipment. Support pipeline companies to build and operate pipelines.	Up to 40 years
Life of Fields	Maintain the asset integrity over the life of field and invest if price of crude/gas is supportive to increase the recovery rate/lengthen the production plateau.	Enhance the production of existing wells. Perform modification and maintenance operations.	Up to 40 years



Exploration

Seismic

Seismic surveys are used to better understand and map underground geological formations. Seismic surveys aim to acquire the sound waves that are reflected by the subsurface and detect anomalies in the rock formations. A series of algorithms are used to map these anomalies where hydrocarbon reservoirs could be located. Seismic companies generally conduct the surveys, process the data, and interpret the results that are used by operators.

Coring and Logging

An exploration well is sometimes drilled to analyze the properties of a field before additional development wells are drilled. Coring and logging can be used in exploration wells to achieve this. Cores are cylindrical samples of rock that can be obtained by drilling an exploration well, or from previous drilling in nearby locations. Core analysis provides information about the properties of the rock layers below ground. Logging refers to a set of instruments that are lowered down a wellbore to map information on the rock layers.

Field Development & Drilling

Land Drilling (Onshore)

Most land rigs are owned by contractors who sell their services to exploration and production companies on a day rate or footage basis.

Most land rigs are owned by contractors who sell their services to exploration and production companies on a day rate (charge by the day) or footage (charge by foot drilled) basis. Rigs vary based on how deep they can drill, their degree of automation (e.g. automatic pipe handling, automated control systems, moving systems, top drives, etc.), and what they are equipped to drill (e.g. Arctic operations, horizontal drilling). Land-based rigs (Exhibit 33) are designed to be quickly assembled and taken apart for fast movement between locations. Some drilling rigs have their own moving systems, while others employ third party trucking companies.

EPCs/Infrastructure

Engineering, Procurement and Construction (EPC) companies help operators design and build the infrastructure required to produce and process hydrocarbons. The nature of this work depends on whether the facilities are onshore, offshore, or subsea:

- **Onshore:** Building onshore production facilities (preparation of drilling site, field gathering and processing facilities, oil sands extraction facilities, LNG facilities).
- **Offshore:** Building offshore production facilities (fixed platforms, semi-submersibles, floating production storage and offloading, floating LNG)
- **Subsea:** Manufacturing of equipment (trees, manifolds) and installation of umbilicals, risers and flowlines that allow the transmission of flow (oil/gas and information) between the subsea production hub and the offshore production facility.

Under a typical EPC contract, service companies are responsible for the engineering & design, the procurement of necessary equipment, the construction (onshore/offshore) or installation (subsea) of the infrastructure, and the commissioning. The construction is often sub-contracted to third parties.

Exhibit 33: Land Rig

Source: Trinidad Drilling

Offshore Drilling

The drilling mechanism for offshore is analogous to land drilling (onshore). The major difference is that an offshore rig needs a platform (fixed or mobile) to support it and there may be hundreds of metres of water between this platform and the sea floor. Different types of offshore rigs are used depending on the water depth, from rigs on submersibles and jack-ups used in more shallow locations, to drillships and semi-submersibles used in deeper locations.

Horizontal and Directional Drilling

In contrast to traditional vertical wells, directional wells use a curved wellbore. Multiple directional wells can be drilled from a single drilling pad. Directional wells are used to extend the wellbore into a larger portion of the resource-bearing formation, which can result in higher resource recovery compared to a traditional vertical well.

Specialized equipment and techniques are used to drill horizontal and directional wells. Down-hole mud motors are used to rotate the bit, which are powered by the pressure of mud (drilling fluid) being pumped down the pipe. Measure-while-drilling (MWD) equipment, with sensors typically located several metres behind the drill bit, is used to measure deviation and help determine if the drilling is on track.

Coiled Tubing

Coiled tubing is a continuous, joint-less, high-pressure rated hollow steel tube that can be used in place of conventional production tubing, which is made of joined sections of pipe and is similar to a drill string. Special equipment is used to insert the coiled tubing (Exhibit 34) through the wellhead into the wellbore. This method is considerably quicker and more efficient than joining sections of pipe.

Exhibit 34: Coiled tubing

Source: Trican Well Service

Drilling Fluids

Drilling fluids are used to stabilize the borehole to prevent cave-in and collapse, to cool the bit, to flow the cuttings up to the surface, and to increase the rate of penetration. Drilling fluids are pumped down the wellbore through the middle of the pipe during drilling, and the "mud" circulates back up between the drill pipe and hole to the surface. Different types of drilling fluids provide different benefits to the drilling operations, depending on the reservoir type.

Service companies manufacture drilling fluid, transport it to site, analyze the mud when it returns to the surface, and dispose of the fluids once the drilling operation is complete.

Rentals

Service companies rent ancillary equipment to operators and other service companies, with examples including tanks, rig mats, power and light generation, waste handling equipment, and flare stacks, to name just a few.

Completion & Production

Casing and Cementing

As the well is being drilled, a thinner steel pipe is added to stabilize the wellbore, which prevents it from collapsing and helps reduce water and contaminants from entering the wellbore. Cementing is used to set the casing in place.

Pressure Pumping/Well Stimulation

Well stimulation uses physical or chemical means to increase the flow of hydrocarbons in the reservoir.

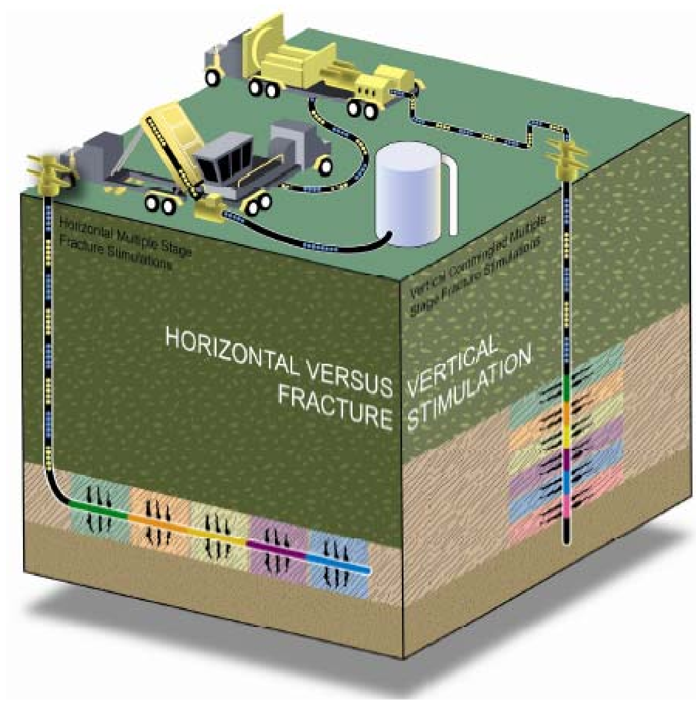
Well stimulation uses physical or chemical means to increase the flow of hydrocarbons in the reservoir. Service companies stimulate a well by pumping liquid down the wellbore and into the reservoir at high pressures. Stimulation can involve acidizing, fracturing, or both.

With acidizing, acid is injected under pressure into the rock formation. The acid dissolves channels in the reservoir, thereby increasing reservoir permeability near the wellbore and, thus, increasing the flow rate.

Stimulation can involve acidizing, fracturing, or both.

With fracturing, fluid such as water or oil is pumped down the hole under sufficient pressure to create cracks (fractures) in the formation. Proppant—a hard substance like sand or ceramic—is injected with the fluid, and as the fluid disperses, the proppant remains to prop open the fractures, thereby increasing the flow of hydrocarbons (Exhibit 35).

Exhibit 35: Fracturing



Source: National Energy Board

Workover

During the course of production, a well may require remedial actions to maintain or improve its production. These operations are frequently called workovers and use workover (or service) rigs. A service rig can look like a small drilling rig and performs tasks like cleaning out a well (removing obstacles that are obstructing the flow of hydrocarbons, such as sand, wax, or rust build-up) or retrieving and replacing a faulty downhole pump.

Transportation to Market

Compression

Gas compression can be used to enhance production from a well or transport the gas to a long-haul pipeline (Exhibit 36). Service companies design, build and operate compressors, offer leasing and rental options, and provide service and parts for existing equipment.

Exhibit 36: Mobile Gas Compression Unit

Source: Total Energy Services

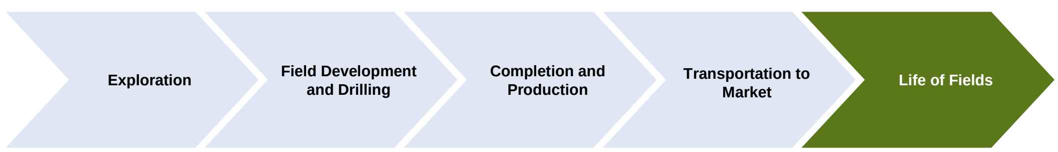
Processing

When hydrocarbons are first produced from a well and before they are transported to market, they often require preliminary processing.

For oil wells, the oil may need to be separated from water or gas which it is mixed with naturally. For natural gas wells, the gas may need to be separated from water and contaminants, like CO_2 and hydrogen sulphide.

Pipelines

Pipelines are used to transport the produced hydrocarbons from the well to market. Service companies are involved in manufacturing, coating, installing, testing, and maintaining pipelines. For more information, please refer to the discussion on Pipelines on Pages 39-40.



Life of Fields

Production Enhancement

As the reservoir is depleted, its pressure may drop resulting in lower rates of production. Several production enhancement alternatives may be used to increase production, including installing surface or down-hole pumps, and drilling water or gas injection wells.

Modification and Maintenance Operations

Service companies also provide modification and maintenance operations on existing infrastructure to maintain or improve the facilities.

Valuation: Net Asset Value (NAV)

In our view, the discounted cash flow (or net asset value) approach is an important method for investors to value oil and gas producers, but variations in methodology and reserve booking practices can result in NAV estimates that are not apples-to-apples comparisons with one another.

Most producers are required to have their reserves evaluated annually by a third party. Evaluating reserves entails a significant degree of judgment, and as such, each evaluator will have a slightly different perspective on asset-specific reserves. Evaluators also report net present value estimates for reserves, which are highly dependent on future commodity price assumptions.

NAV calculations take into account booked reserves as at the most recent year-end, which include 2P (Proven + Probable) reserves. A common approach is to utilize a "blow-down" scenario (allowing reserves to decline naturally) for the Proved Developed Producing (PDP) reserves, and then layer on future development of the Proved Undeveloped (PUD) and Probable reserves as per the reserve evaluators' drilling and future development capital (FDC) schedule.

Typically, NAV calculations take into account booked reserves as at the most recent year-end, which include 2P (Proven + Probable) reserves.

Most NAVs are calculated by taking the present value (using an appropriate discount rate) of after-tax cash flows and adjusting for the estimated value of land and balance sheet items such as other assets and hedges, and deducting reported net debt and other balance sheet items (Exhibit 37). Cash flow projections are based on a specific commodity price forecast – most investors will use their own proprietary deck, the futures strip at the time of calculation, or the reserve evaluators' forecast. NAV per share (NAVPS) is calculated on a fully diluted basis.

As there is a high degree of reserve "booking variability", investors must often rationalize their view of what is included in the company's booked reserves and what they consider to be "unbooked exploration/development upside" associated with a particular company's assets.

Exhibit 37: SampleCo NAV Summary

SampleCo

2P NAV Breakdown & Risked Upside

	Reserves (mmboe)	NPV, Unrisked ($MM)	NPV, Unrisked ($/share)	Risk Factor (%)	NPV, Risked ($MM)	NPV, Risked ($/share)
Proven plus Probable Reserves	80	$1,040	$8.60	100%	$1,040	$8.60
Land Value		$148	$1.22	100%	$148	$1.22
				100%	$0	$0.00
Total Assets		**$1,188**	**$9.82**	100%	**$1,188**	**$9.82**
Net debt		-$312	-$2.58	100%	-$312	-$2.58
PV of G&A costs		-$27	-$0.23	100%	-$27	-$0.23
Other assets/liabilities and option proceeds		$26	$0.22	100%	$26	$0.22
2P NAV		**$874**	**$7.23**	100%	**$874**	**$7.23**
Less: Land Value					-$22	-$0.18
Adjusted 2P NAV					**$852**	**$7.05**

	Unbooked Locations (#)	Recovery per Well (mboe/well)	Unrisked Resource (mmboe)	NPV, Unrisked ($MM)	NPV, Unrisked ($/share)		NPV, Risked ($MM)	NPV, Risked ($/share)
Play #1	200	510	102	$1,050	$9.06	75%	$788	$6.80
Play #2	500	775	388	$1,370	$11.83	25%	$343	$2.96
Play #3	320	380	122	$1,900	$16.40	50%	$950	$8.20
Total	**1,020**		**611**	**$4,320**	**$37.29**		**$2,080**	**$17.95**
2P NAV + Risked Upside			**691**	**$5,172**	**$44.34**		**$2,932**	**$25.00**

Source: Company Reports, RBC Capital Markets estimates

Valuation: Trading Multiples

Along with NAV analysis, comparing oil & gas producers on a variety of near-term trading metrics (that utilize the prevailing market price of a company's shares) can allow an investor to determine whether a stock has a favourable or unfavourable relative valuation versus its peers. Some of the most common multiples include cash flow (Exhibit 38), production (Exhibit 39), and reserves (Exhibit 40) metrics.

Exhibit 38: Cash Flow Metrics

EV / DACF

$$\rightarrow \frac{\text{Enterprise Value}}{\text{Debt Adjusted Cash Flow}} \rightarrow \frac{\text{Market Capitalization + Net Debt}}{\text{Cash From Operations + [Interest*(1 - Tax Rate)]}}$$

P / CFPS

$$\rightarrow \frac{\text{Price}}{\text{Cash Flow per Share}} \rightarrow \frac{\text{Share Price}}{\text{Cash From Operations / Weighted Avg Shares O/S}}$$

Source: RBC Capital Markets

The above cash flow metrics attempt to answer the question "How much are you paying per dollar of cash flow generated by the company's day to day operations?" The difference between the two is the effect of debt outstanding on a company's balance sheet (i.e., "leverage"). Using **EV/DACF** vs. **P/CFPS** results in a "debt neutral" comparison between companies, allowing for a cleaner comparison between their cash-generating operations, regardless of capital structure.

Exhibit 39: Production Metrics

EV / boe/d

$$\rightarrow \frac{\text{Enterprise Value}}{\text{Average Daily Production}} \rightarrow \frac{\text{Market Capitalization + Net Debt}}{\text{Barrels of Oil Equivalent Produced / Period Days}}$$

Field Netback (per boe)

$$\rightarrow \frac{\text{Gross Profit}}{\text{Produced Barrels}} \rightarrow \frac{\text{Revenue - (Royalties + Op Costs + Transportation)}}{\text{Barrels of Oil Equivalent Produced}}$$

Source: RBC Capital Markets

Enterprise Value per Flowing Barrel (EV / boe/d) attempts to answer the question "How much are you paying per barrel of existing production?" That is, how expensive is the company with respect to its current upstream operations? It is important to understand why the market might be assigning a high multiple to a particular company before assuming that it is simply overpriced - is production weighted to oil? If so, the associated revenue and gross profit will be higher if the prevailing oil price environment is stronger than the natural gas market. Are production volumes about to grow? The market is forward-looking: if investors are aware of an event that will cause production to increase significantly (reducing the future multiple), they may be willing to pay now for that growth.

Field Netback shows an investor the take-away or "keep" - i.e., How much margin is generated from a produced barrel after standard costs are factored in? It attempts to indicate asset profitability before factoring in corporate items such as G&A expense, interest and cash taxes.

Exhibit 40: Reserves Metrics

EV / boe reserves $\Rightarrow \dfrac{\text{Enterprise Value}}{\text{Reserves}} \Rightarrow \dfrac{\text{Market Capitalization + Net Debt}}{\text{Barrels of Oil Equivalent Booked to Reserves}}$

FD&A Costs (incl. Δ FDC) (per boe) $\Rightarrow \dfrac{\text{Development Capital + Acquisition Capital + Incremental Change in FDC}}{\text{Gross Additions to Booked Reserves}}$

Recycle Ratio $\Rightarrow \dfrac{\text{Field Netback}}{\text{FD\&A Costs (incl. } \Delta \text{ FDC)}}$

Source: RBC Capital Markets

Enterprise Value-to–Reserves (EV/boe) attempts to answer the question "How much are you paying per barrel of booked reserves?" or "How much are you paying per barrel still in the ground?" The majority of an upstream producer's value resides in the future potential of its oil & gas assets, and investors may be willing to pay more for a "future barrel" in some cases (i.e., if the reserves are oil-weighted). Again, in the case of a strong oil environment vs. a weak natural gas market, oil-weighted reserves should result in comparatively higher future revenue and gross profit. If the majority of booked reserves are classified as PDP (proved developed producing), it's likely that the future cost to bring them onto production is lower than with other classifications of reserves.

Finding, Development & Acquisition (FD&A) costs demonstrate the cost associated with identifying a barrel of reserves and bringing it on production. Reserves can be found organically (i.e., on the company's existing asset base) or they can be bought (i.e., a company acquires an asset with reserves from another producer). Either way, the result is an addition to the reserves book which comes at an expense, and this metric attempts to demonstrate that cost. The incremental change in undiscounted **future development capital (FDC)** is included to equalize the metric with respect to the classification of reserves added. If all of the added reserves are categorized as "probable" then the risk and cost associated with developing those reserves is likely higher than reserves added to the PDP category.

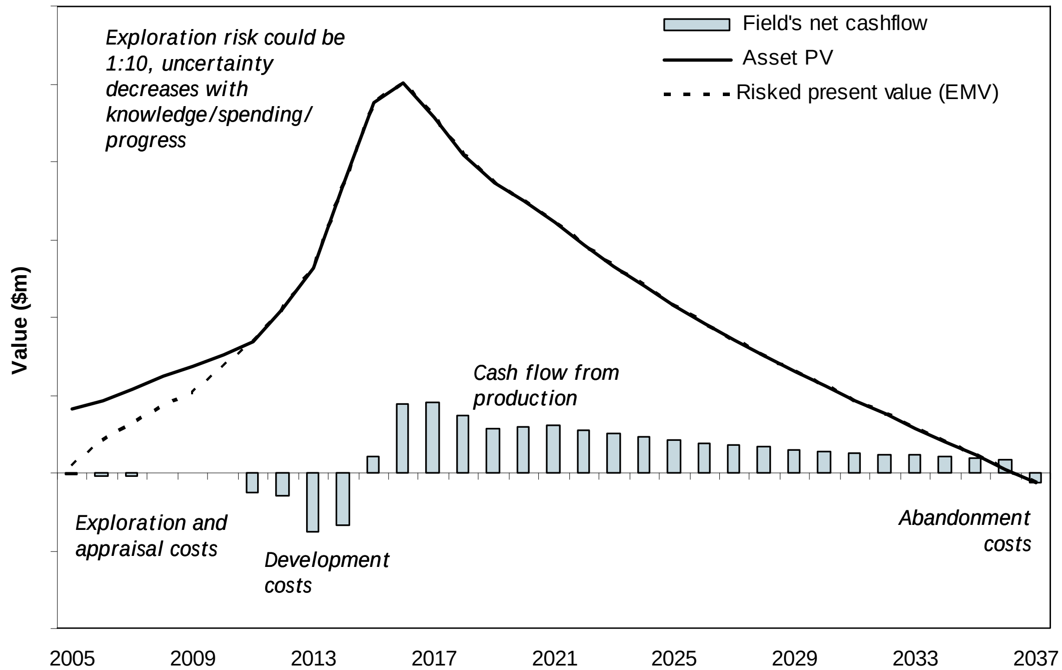
The **Recycle Ratio** indicates the level of profitability of an oil or gas asset (i.e., field profit per barrel as a multiple of the cost to find and develop that barrel). When choosing between assets for development, those with higher recycle ratios are likely to be favoured due to higher associated returns.

Valuation: International E&P

Value Curve

In order to simplify what can appear to be a complex and risky investment, International E&P companies can be plotted on a “value curve” to assess the momentum of the company and the balance of its portfolio. This curve is presented in Exhibit 41 for a typical “defining asset” and therefore a simplified single asset “model” company. Exhibit 42 shows the stock price reaction.

Exhibit 41: Exploration & Production Value Curve



Source: RBC Capital Markets

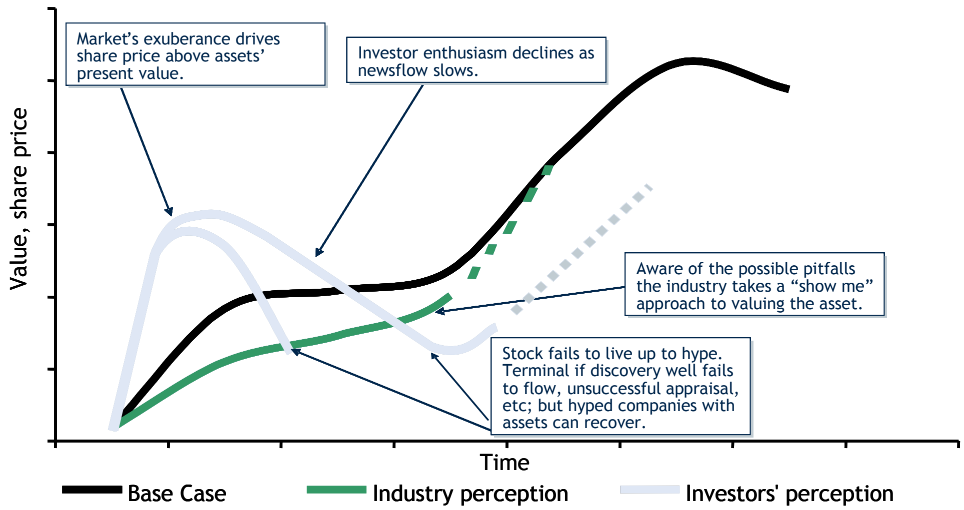
Exploration - Exploration is the phase where tens of millions of dollars typically are invested, which may or may not be recouped. Simultaneously in this phase, share price growth can be rapid on success and/or anticipation of success. If the drilling results in a sizeable discovery, the company should experience rapid value accretion with uncertainty decreasing as knowledge increases, de-risking other nearby drilling. The vast blocks often available within the International E&P space can provide repeatability and further momentum and upward growth in the share price.

Commercialisation - Following the initial exploration results, investors can tire as the discoveries need appraisal and are commercialized, which often takes a number of years. In a worst case scenario, exploration success is followed by appraisal failure.

Development - As discoveries are developed (rapidly with onshore oil, much slower with offshore gas in new markets), share price appreciation slows and stocks often lose momentum (e.g. during pipeline construction). However, as the project is delivered, value growth is steady and significant industry players pay more attention, with the potential for mergers & acquisitions if the equity market undervalues the stock.

Production - When a key “defining asset” comes on-stream, the company needs to have a portfolio that provides reinvestment opportunities to allow momentum and investor excitement to keep building around the expectation of a repeated success.

Exhibit 42: Value Curve – How Stocks React



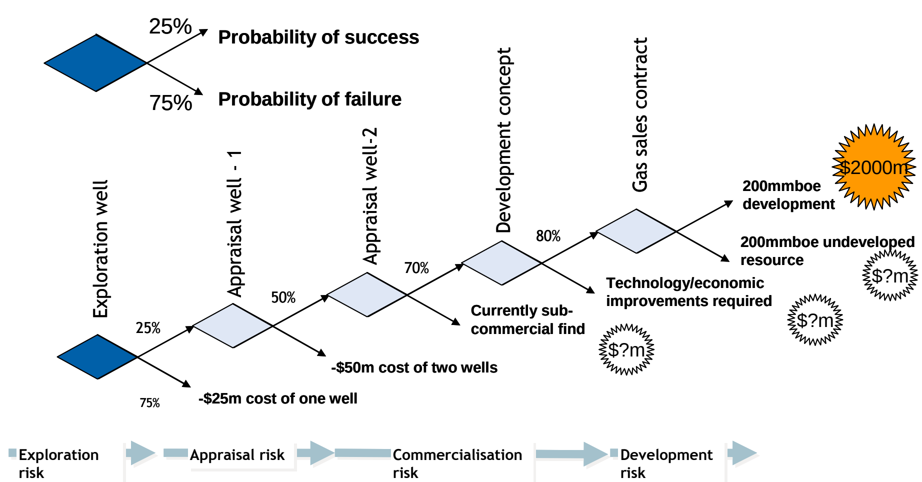
Source: RBC Capital Markets

Valuation – International E&P vs. Majors

The valuation of international E&P companies differs significantly from the major oil companies. The smaller scale of the company allows for a more granular valuation built on the present values of producing assets (using the appropriate fiscal terms). E&Ps can be valued on an asset-by-asset basis comprising three key elements: 1) the commercial core – fields on stream and under development, 2) the risked upside—undeveloped fields and exploration, and (3) financials—net debt adjusted for deals less exploration costs (for a committed 12-month drilling program). For producing fields, a detailed field model can be generated, taking into consideration the fiscal regime and relevant pricing to form a discounted cash flow valuation.

The risked upside comprises a risked value of the fields under development and an expected monetary value (EMV) for the scheduled exploration programs (Exhibit 43). Acreage value need not be included unless there is a commitment to drill and sufficient financing. The EMV of an exploration program is calculated by multiplying the prospect size by an appropriate $/boe metric, then by a chance of success, and finally by the equity stake. This chance of success typically ranges from 1-in-10 (wildcat wells) to 1-in-2 for appraisal wells. As a discovery is made, the drilling will partially be de-risked and the risk factor will subsequently be unwound as the discovery is appraised. Exploration upside is a key value driver for many investors, but considerable uncertainty is associated with its interpretation / assessment.

Exhibit 43: A Simple Expected Monetary Value "EMV"



Source: RBC Capital Markets

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Valuation: Oilfield Services

Oilfield Services companies are typically valued using one of three methods: (1) EV/EBITDA multiple, (2) P/E multiple, and (3) sum of the parts. Unlike E&P companies, service companies are not frequently valued using discounted cash flow methods.

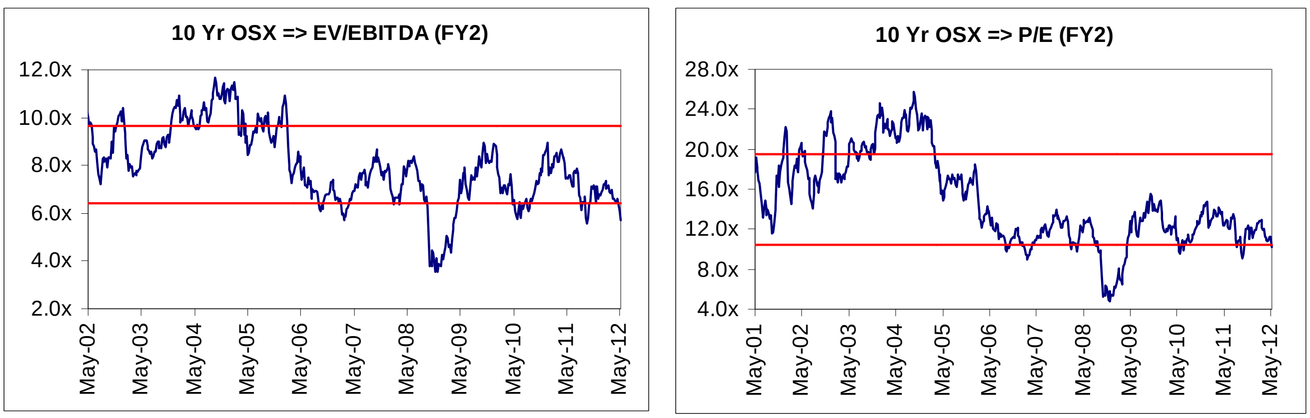
EV/EBITDA and P/E multiples

EV/EBITDA and P/E multiple methods are very similar and will be discussed together. The multiple that a company trades at will depend on various factors, including growth prospects, risk profile, stage in the oilfield services cycle, and strength of leadership team.

Influencing Factor	Higher Multiple	Lower Multiple
Growth prospects	Strong growth prospects	Weak growth prospects
Risk profile	Lower financial and/or operational risk	Higher financial and/or operational risk
Stage in oilfield services cycle	Early (trough earnings)	Late (peak earnings)
Strength of leadership team	Experienced, strong track record of value creation	New, little record of value creation

The most widely tracked sector index is the Philadelphia Stock Exchange Oil Service Sector Index (OSX). Over the past ten years, the value of the index has averaged 8.0x forward year EV/EBITDA, with a one standard deviation range of 6.4x-9.6x, and has averaged 14.6x forward P/E, with a one standard deviation range of 10.0x-19.2x (Exhibit 44).

Exhibit 44: Ten-Year OSX Forward Year EV/EBITDA and P/E Multiples



Source: FactSet, RBC Capital Markets estimates

Sum of the Parts

Sum of the parts valuation is frequently used when companies are involved in more than one major sub-segment of the oilfield services industry. Under this approach, EBITDA is estimated for each segment of the company. A multiple appropriate to each segment is then applied to determine an enterprise value (EV) for each segment, which are then summed to determine an appropriate EV for the company as a whole.

Investing: Commodities vs. Equities

Generally, an investor can gain exposure to commodities either **directly** or **indirectly.** One can gain exposure directly through the spot (cash) market or by purchasing futures contracts. Alternatively, an investor can obtain indirect exposure through the purchase of equity investments in companies that have claim to crude oil and/or natural gas properties.

Commodities

Spot Market

The return on an investment in the spot market is simply the change in spot price for a physical barrel of crude oil. One drawback of holding the physical commodity is the storage cost, which is why investors tend to prefer the use of derivatives to gain exposure to the underlying commodity.

Futures Market

The futures market is somewhat more complex and consists of three components: (1) spot return, (2) collateral return, and (3) roll return.

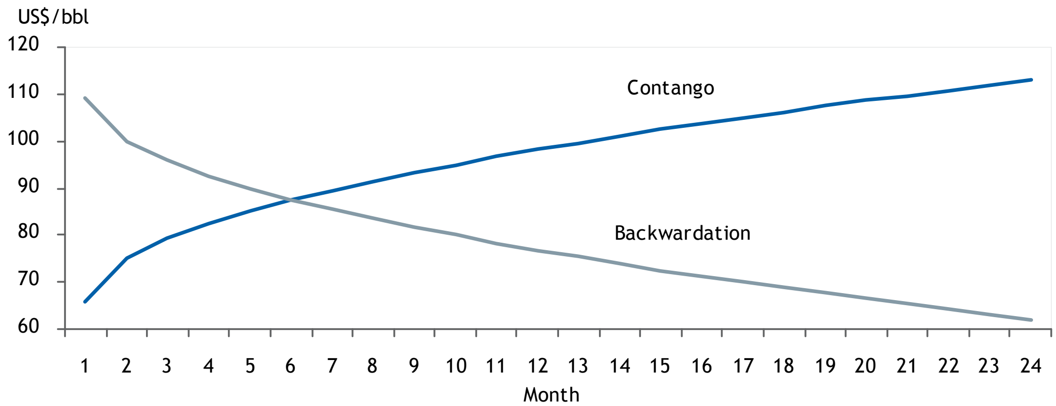
The **spot return** is calculated as the change in the spot price for the commodity. The **collateral return** is the opportunity cost of having the collateral (generally cash in T-bills) earn the risk-free rate. The **roll return** arises from purchasing or rolling the long futures forward.

To illustrate the roll return (Exhibit 45), a price curve can take three general shapes (1) upward sloping (contango), (2) downward sloping (backwardation), or (3) flat. When the curve is upward sloping, the futures contract is trading above the spot price, which means that under a buy and hold strategy, an investor will lose if spot prices remain constant as the futures contract converges to the spot price. The opposite is true if the curve is in backwardation.

Below is an example of how an investor can lose money if the curve is in contango and the investor decides to roll the contract forward.

If the spot price is $60/bbl and an investor buys the next month futures contract at $65/bbl, the holder of the futures contract will lose $5/bbl if spot prices remain flat at $60/bbl. This would translate to a negative roll return of 8%.

Exhibit 45: Contango vs. Backwardation



Source: RBC Capital markets

Equities

An example of an indirect investment in commodities could involve purchasing shares of companies that produce crude oil. However, given that some companies hedge their oil production, have natural gas assets and/or refining businesses, the correlation between crude oil and the underlying share price can vary widely.

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Investing: E&P Bonds

What Do Credit Investors Focus on?

Similar to equity investors, credit investors analyze the fundamentals of the business. There is a divergence in company strategy between the two asset classes, since what may be positive for equity holders may not necessarily be true for bondholders. Although growth and free cash flow are important factors in assessing a company's credit quality, leveraging up a balance sheet for earnings accretion is, for the most part, not looked upon favourably by bond investors. Other examples of events detrimental to bondholders include dividend increases, stock repurchases, etc.

Credit analysis takes into consideration the business and financial risks of a company. The business risk profile for an energy company involves analyzing the cash flow and geological basin diversification, major non-E&P specific operations (additional business risk), size, production and reserve concentrations, reserve life, reserve replacement, and ownership to name a few. Generally, within the investment grade universe, well established companies that generate stable free cash flows to meet interest and principal requirements, combined with a solid balance sheet, are preferred. To sum it all up, assessing credit risk is the most important part of the analysis, as the main focus will be on the company's ability to repay the principal and to meet its annual coupon payments for the duration of the underlying bond.

Within the E&P investment grade universe, credit investors tend to focus on the following credit metrics when assessing the company's financial risk profile (Note: these are just some of the ratios used):

- Debt-to-Capital
- Debt-to-EBITDAX
- EBITDAX-to-Interest
- FFO-to-Debt
- Full-Cycle Coverage Ratio
- Debt-to-Average Daily Production
- Debt-to-PD Reserves (boe)

Note:
EBITDAX = Earnings before interest, taxes, depreciation, amortization and exploration expense
FFO = Funds from operations
PD = Proven developed

Credit Ratings

In Canada, there are three main rating agencies: DBRS, S&P, and Moody's. A credit rating is an independent opinion on the creditworthiness of an issuer and can influence the pricing of the bonds. Each rating agency has its own letter designation with AAA / AAA / Aaa (DBRS / S&P / Moody's) having the strongest credit quality, and D / D / C (DBRS / S&P / Moody's) having the lowest. All rating categories also contain subcategories indicating the directional outlook of the credit rating.

- DBRS (AAA to D with subcategories Low, Mid and High)
- S&P (AAA to D with subcategories Negative, Stable and Positive)
- Moody's (Aaa to C with subcategories Negative, Stable and Positive)

Covenants

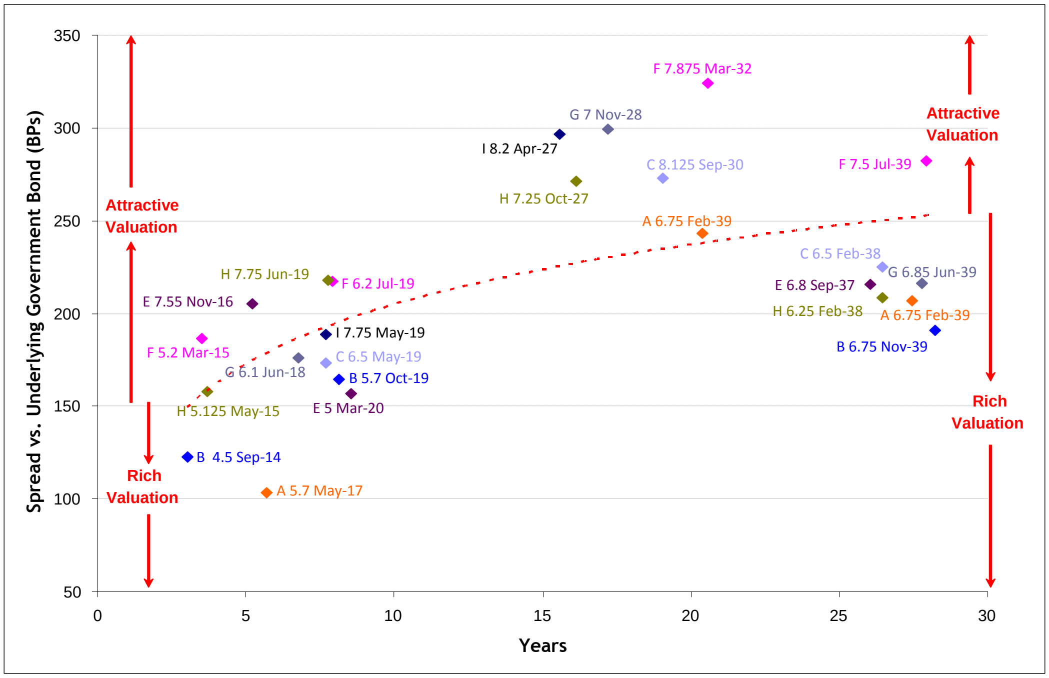
A trust indenture is a legally binding agreement between the company and the bondholders, which includes covenants that set obligations to protect the bondholders. Covenants set limits on the company's incurrence of additional debt, liens, asset sales and the use of proceeds, priority claims over assets, and minimum coverage; as well as leverage ratios the company must maintain on a regular basis (usually quarterly). Within the E&P investment grade universe, indentures do not typically include financial covenants. In most cases, stronger credit companies will have lighter covenants while weaker companies will have tighter covenants that include financial covenants.

Valuation

When valuing a bond, investors generally focus on the spread (in basis points) over the underlying government yield. Although the overall yield is important, spreads, or the additional yield investors receive for holding corporate bonds, allow investors to compare the fundamental risk of the company with its peers.

Exhibit 46 is an example of a Relative Value chart, which lays out the spreads and maturity profile of various bonds. The dashed line is the yield curve for all the bonds in this example. This line provides a quick overview of what looks expensive and cheap, before giving consideration to the various credit-related factors that weigh into the valuation of individual bonds. Bonds with spreads below the line are considered to be expensive, while those that are above the line are cheap. Like stocks, companies with strong credit fundamentals will tend to trade at premium valuations, while the opposite is usually true for lower quality names.

Exhibit 46: Relative Value Chart



Source: RBC Capital Markets estimates

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Appendix I: Sample Press Release

TRILOGY ENERGY CORP.

Calgary, Alberta
February 9, 2011

NEWS RELEASE: TRILOGY ENERGY CORP. ANNOUNCES RESULTS FROM NEW HORIZONTAL MONTNEY OIL PLAY

Trilogy Energy Corp. ("Trilogy" or the "Company") (TSX: TET) is pleased to announce results on its Montney oil development in the Kaybob area.

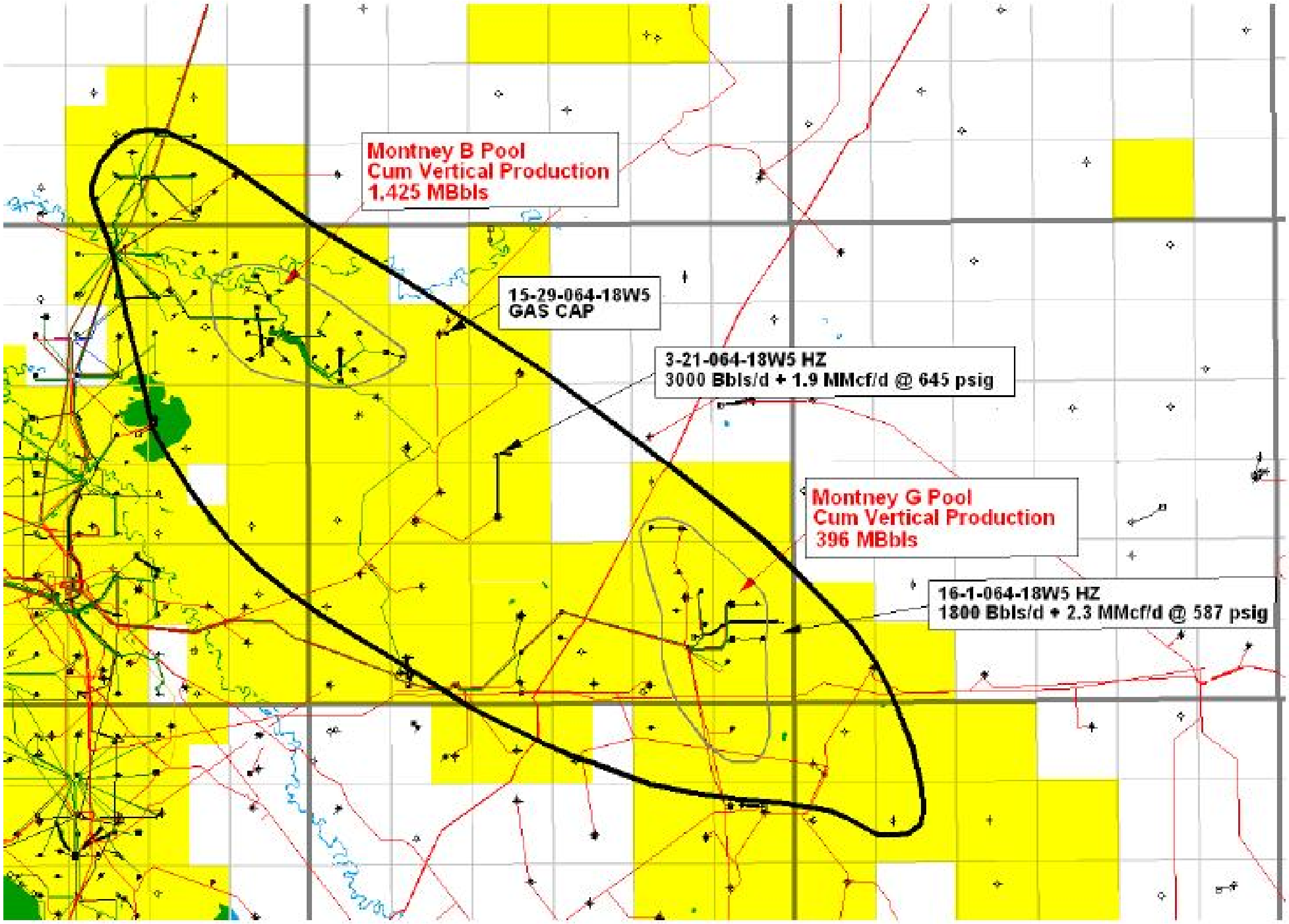
Kaybob Montney Oil Development

Trilogy has successfully applied horizontal drilling and multi-stage fracturing techniques to exploit a Montney oil pool in the Kaybob area of Alberta. In the fourth quarter of 2010, Trilogy completed drilling operations on a horizontal Montney oil well at 16-1-64-18W5 (the "16-1 Well"), and completed it using a 15 stage fracture stimulation. Following recovery of the completion load fluid, the 16-1 Well flowed crude oil at 1,800 bbl/d. During the first full month of production, this well produced at average rates of 500 bbl/d of crude oil and 1 mmcf/d of natural gas.

Trilogy followed up on the success of the 16-1 Well by drilling a second horizontal Montney oil well to further delineate the Montney oil pool. The second well was drilled as a vertical well at 6-16-64-18W5 in order to core the Montney formation; it was subsequently plugged back to a kick off point and drilled horizontally through the Montney to a total depth of 3,120 m, with a bottom hole location at 3-21-64-18W5. The lateral portion of the well was 1,158 m in length and completed with a 15 stage fracture stimulation. Trilogy was able to flow back the well immediately prior to today's Alberta Crown land sale, recovering all 3,650 barrels of completion fluid and 1,600 barrels of oil in the first 24 hours of production. The final rate during flow back was 1.9 mmcf/d of natural gas and 3,000 bbl/d of crude oil (40 degree API) at a flowing pressure of 4,450 kPa (645 psi).

Based on the success of these two horizontal Montney oil wells, Trilogy acquired 28 sections of land along the Montney trend in this area at today's Alberta Crown land sale at a cost of $32.2 million. With a 100 percent working interest in 41 sections of land along the trend, Trilogy believes it now holds substantially all of the petroleum and natural gas rights associated with this Montney oil pool and will evaluate accelerating the development of this play in the second half of 2011. Trilogy anticipates drilling further delineation wells, and that the pool will require four to eight horizontal wells per section to fully exploit the Montney reservoir. Trilogy also believes that this land may also prove to be prospective in the Duvernay shale.

The map below illustrates Trilogy's land position on the Montney oil play in the Kaybob area. The prospective lands lie between and within two existing Montney oil pools.



About Trilogy

Trilogy is a petroleum and natural gas-focused Canadian energy corporation that actively acquires, develops, produces and sells natural gas, crude oil and natural gas liquids. Trilogy's geographically concentrated assets are primarily low-risk, high working interest, liquids-rich, lower-decline properties that provide abundant infill drilling opportunities and good access to infrastructure and processing facilities, many of which are operated and controlled by Trilogy. Trilogy's common shares are listed on the Toronto Stock Exchange under the symbol "TET".

Key Take-Away Points / Follow-up Questions from the Press Release:

Title:

… NEW HORIZONTAL MONTNEY OIL PLAY…

- **Follow-up:** Is this an event that the market was not previously aware of? If so, is it important enough to move Trilogy's stock price? Is it good news or bad news? Does it change the fundamental value of the company in the long-term, or is it a short-term or temporary change?
- **Take-away:** In this case, the term "new" seems to indicate that this is Trilogy's first announcement about the oil pool. As TET is announcing success in discovering a new play to add to its portfolio of assets, it is very likely to move the stock price upwards given that the news is positive, and it would be a long-term fundamental change to Trilogy's value.

First Paragraph:

… Montney oil pool in the Kaybob area of Alberta…

- **Take-away:** This line tells you the formation (Montney), product (oil vs. gas), field (Kaybob) and province (Alberta) where the pool was identified.

…horizontal Montney oil well at 16-1-64-18W5…

- **Take-away:** This line tells you the type of well (horizontal vs. vertical) and its UWI (Universal Well Identifier) which can be used to locate the well on a map.
- **Follow-up:** Are there other wells nearby that might be targeting the same oil pool? If so, how have they performed? Who are they operated by?

…flowed crude oil at 1,800 bbl/d… first full month of production, this well produced at average rates of 500 bbl/d of crude oil and 1 mmcf/d of natural gas…

- **Take-away:** Trilogy is providing information about the well's test rates and IP (Initial Production) rates, as well as the composition of oil vs. gas flowing from the well.
- **Follow-up:** What was the duration of the test? From above, how have other wells nearby performed? What were the costs associated with this well?

Second Paragraph:

… second horizontal Montney oil well to further delineate the Montney oil pool…

- Take-away: There is a second well to collect information on – its purpose was to delineate the pool (i.e. further identify where the pool is prospective on TET's land base)

…. bottom hole location at 3-21-64-18W5…

- Take-away: UWI of the second well to use in similar fashion as the first well UWI.

…. 1,600 barrels of oil in the first 24 hours of production. The final rate during flow back was 1.9 mmcf/d of natural gas and 3,000 bbl/d of crude oil (40 degree API) at a flowing pressure of 4,450 kPa (645 psi)…

- **Take-away:** For the second well, Trilogy has provided the duration of the test (24 hours). The company has also provided the final rate, the composition of oil and gas, the gravity (light vs. heavy oil) and the pressure at the wellhead – all useful information to help understand the reservoir's characteristics, which are important when determining its value to Trilogy.

Third Paragraph:

… Trilogy acquired 28 sections of land along the Montney trend in this area… cost of $32.2 million …

- **Take-away:** Trilogy purchased some land rights where they feel the pool is prospective.
- **Follow-up:** Where are the land sections they purchased relative to their existing land base? How much did they pay on a per-section basis? How did they finance the transaction?

…. 100 percent working interest in 41 sections of land along the trend …

- **Take-away:** This line indicates Trilogy's overall position in the play, as well as the percentage working interest – important information when determining the impact this new play could have on the company's overall production and growth.

…. Trilogy anticipates drilling further delineation wells …

- **Take-away:** This line indicates Trilogy's next steps in developing the play, and where they will be directing capital spending, as well as what future updates are likely to be announced (i.e. further well results).
- **Follow-up:** Where will these wells be drilled in relation to the first two? Will they be vertical or horizontal wells? Will they use the same completion technology as the first two? Will they cost more / less / the same as the first wells?

… pool will require four to eight horizontal wells per section …

- **Take-away:** Trilogy is providing an indication of how many future wells could be drilled to fully exploit the new oil pool.
- **Follow-up:** How many future locations does this represent? Based on surrounding land development, is four wells per section too conservative? Is eight wells per section to optimistic?

…. this land may also prove to be prospective in the Duvernay shale …

- **Take-away:** Along with Montney oil, Trilogy is announcing that they believe the same land may be prospective for another formation, which could provide future sources of production growth.
- **Follow-up:** What are Trilogy's drilling plans for testing and delineating the Duvernay shale? How much is this expected to cost? Is the Duvernay shale an economic play? Is it oil or gas? How many sections of Trilogy's land is prospective for the play? Are there competitors nearby who are exploring the Duvernay? How have the results been relative to the cost of the wells?

Fourth Paragraph / Map:

… Trilogy's land position on the Montney oil play in the Kaybob area …

- **Take-away:** The provided map gives a visual representation of Trilogy's new oil play, its land base within the play, the locations of the first two exploration wells, and existing development on the lands.

Appendix II: Glossary of Terms

Term	Definition
1C	Denotes low estimate scenario of Contingent Resources.
2C	Denotes best estimate scenario of Contingent Resources.
3C	Denotes high estimate scenario of Contingent Resources.
1P	Taken to be equivalent to Proved Reserves; denotes low estimate scenario of Reserves.
2P	Taken to be equivalent to the sum of Proved plus Probable Reserves; denotes best estimate scenario of Reserves.
3P	Taken to be equivalent to the sum of Proved plus Probable plus Possible Reserves; denotes high estimate scenario of reserves.
Absolute Open Flow Rate	The greatest rate from which gas can flow through the wellbore to the surface from one particular reservoir.
Accumulation	The process of petroleum collection in a reservoir, or the collected body of petroleum itself.
Acidizing	Treatment of oil-bearing limestone or carbonate formations with a solution of hydrochloric acid and other chemicals to increase production. The acid is forced under pressure into the formation where it enlarges the flow channels by dissolving the limestone.
Aggregation	The process of summing reservoir (or project) level estimates of resource quantities to higher levels or combinations such as field, country or company totals. Arithmetic summation of incremental categories may yield different results from probabilistic aggregation of distributions.
Allowable	The amount of oil or gas that a well is permitted by authorities to produce during a given period.
Analogous Reservoir	Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but they are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery.
Anomaly	A regional or local change in the structural settling of subsurface rocks which has been detected by the use of geologic or geophysical studies and which may be the site of oil or gas accumulation.
Anticline	A fold, the core of which contains older rocks. It is convex upward. Anticlines make excellent structural traps for the accumulation of oil or gas.
API Gravity	An arbitrary scale expressing the gravity or density of liquid petroleum products. The measuring scale is calibrated in terms of API degrees. It may be calculated in terms of the following formula: Degree API = (141.5 / Specific Gravity @ 60^{o}F) - 131.5
Appraisal Well	This occurs following the success of an exploratory well and will be part of the beginning of the delineation of the area that will determine the physical extent, reserves, and likely potential production rate of the reservoir.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is underway.
Aquifer	An underground water reservoir contained between layers of rock, sand, or gravel.
Area of mutual interest	An area designated, under an agreement for a period of time, around a well being drilled by two or more parties within which each party has the right to participate in any new drilling activities or land acquisitions of the other.
Asphaltic oil	Crude oil with asphaltic characteristics.
Assessment	See Evaluation.
Associated Gas	Associated Gas is a natural gas found in contact with or dissolved in crude oil in the reservoir. It can be further categorized as Gas-Cap Gas or Solution Gas.
Authority For Expenditure (AFE)	The authorization for the spending of the estimated cost of a capital investment by each of the parties responsible for a share of the cost
Back-In	The conversion of a (smaller) cost-free interest to a (larger) working interest in a well, normally occurring when the original capital investment in the well has been returned (at payout).
Bar	An elongated detrital ridge, mound, or bank deposit by marine waves and current, or rivers and streams.
Barrel	Standard unit of measurement in the petroleum industry. The metric measure is a cubic meter, which is 6.293 times the size of a barrel. One barrel (bbl) is the equivalent of 35 imperial (Canadian) or 42 US gallons. The metric unit of measure is the cubic meter. 1 barrel = 1.5891 m^3.

Term	Definition
Basin	A geologic region of sediments formerly occupied by an ancient sea and separated from other basins by upwarped rock "highs."
Basin-Centred Gas	An unconventional natural gas accumulation that is regionally pervasive and characterized by low permeability, abnormal pressure, gas saturated reservoirs, and lack of a down-dip water leg.
Battery	Tanks, separators, and other production equipment serving a number of wells used to bring oil to a marketable condition where it can be sold to the pipeline.
Beach	A deposit of wave-washed sediment along a coast between the landward limit of a wave action and the outermost breakers.
Bed	A layer of sediment 1 cm or more thickness.
Behind-Pipe Reserves	Behind-pipe reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion prior to the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Best Estimate	With respect to resource categorization, this is considered to be the best estimate of the quantity that will actually be recovered from the accumulation by the project. It is the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
Bit or Drill Bit	An attachment to the end of the drill string, consisting of three conical heads. Rotation of the string during drilling rotates the toothed heads as well, and cuts the rock.
Bitumen	Migratable hydrocarbon formed from thermal alteration of kerogen. A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and that, in its naturally occurring viscous state, will not flow to a well.
Blowdown	The production of gas by expansion, either from the gas cap of an oil reservoir, normally after depletion of the oil, or from a cycled gas pool upon cessation of the cycling operation.
Blowout	A sudden, violent escape of oil, gas, and mud (and sometimes water) from a drilling well, followed by uncontrolled flow from the well. It occurs when high pressure gas is encountered and sufficient precautions, such as increasing the weight of the drilling mud or assuring that blowout preventers work properly, have not been taken.
Bonus	Money paid to a landowner or other holder of mineral rights by the lessee for the execution of an oil and gas lease in addition to any rental or royalty obligations specified in the lease.
Borehole	The hole generated by drilling activity.
Bottom hole choke	A device placed at the bottom of the tubing to restrict the flow of oil or to regulate the gas-oil ratio.
Bottom hole pump	A compact, high-volume pump located in the bottom of a well, not operated by sucker rods or a surface power unit.
Bottom hole pressure	The pressure in a well at a point opposite the producing formation.
Break-Up	The period of the year when the ice on rivers break up and the frost comes out of the ground, usually in late March and April in Alberta. Road-bans and weight restrictions are imposed, restricting equipment movement.
Bring on a well	The act of completing and bringing a well into actual production status. A well is considered complete when it has been acidized, fractured, and the Christmas Tree or wellhead has been installed.
BTU (British thermal unit)	A standard measure of heat content in a fuel. One BTU equals the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit at or near 39.2 degrees Fahrenheit.
Butane	Flammable gaseous paraffin hydrocarbon, C_4H_{10}, obtained from crude petroleum and natural gas.
Buy Back Agreement	An agreement between a host government and a contractor under which the host pays the contractor an agreed price for all volumes of hydrocarbons produced by the contractor. Pricing mechanisms typically provide the contractor with an opportunity to recover investment at an agreed level of profit.
Canadian exploration and development overhead expenses (CEDOE)	General and administrative costs, indirectly related to exploration and development activities, which are capitalized on CEE and CDE expenses and are deducted from resource profits used to determine resource allowance.
Canadian development expense (CDE)	Any expense other than a Canadian exploration expense, incurred in drilling or completing an oil or gas well prior to the commencement of production in commercial quantities from the well, or in drilling or converting a well to dispose of waste liquids or to inject materials to assist in the recovery of petroleum and natural gas from another well.

Term	Definition
Canadian exploration expense (CEE)	Any expense incurred in determining the existence, location, extent, or quality of an accumulation of petroleum or natural gas, or a mineral resource in Canada. CEE includes geological, geophysical and geochemical expenses and any expenses relating to the first well capable of commercial production that is drilling in an area where hydrocarbons were not previously known to exist.
Canadian oil and gas property expense (COGPE)	Any expense incurred in acquiring any right, privilege to explore for, drill for or take petroleum, natural gas or related hydrocarbons in Canada, any oil or gas well in Canada, or any rental or royalty computed by reference to the amount of value of production from an oil or gas well in Canada other than payment made for the preservation of such property.
CAOF (calculated absolute open flow)	A figure representing a gas well's theoretical producing capability per day.
Capped well	A well capable of production but lacking wellhead installations and a pipeline connection.
Carried Interest	A carried interest is an agreement under which one party (the carrying party) agrees to pay for a portion or all of the pre-production costs of another party (the carried party) on a license in which both own a portion of the working interest.
Cash calls	Money requested in advance by operator from participants in a well for capital costs
Casing	Steel pipe that is cemented into place in an open-hole. Casing should be designed to exclude unwanted fluids, control well pressure and support the well bore from collapsing. Casing is also run to protect fresh water formations, isolate a zone or isolate formations with significantly different pressure gradients.
Casing point	Stage of a well after the casing has been cemented, but before production tubing has been installed.
Casing String	Joints of connected casing cemented in a well to protect the hole from caving of the wall, to prevent entry of fluids from other strata, and to permit selective production through perforations, slots or an uncased hole below the pipe.
Cementing	The operation by which a slurry of cement is forced through casing and up around its lower end, filling the space between the casing and the wall of the hole to a selected height. The purpose is to secure the casing in place and to allow for uncontaminated production of oil/gas from the specifically selected horizon(s).
Channel sand	Sandstone rock which has formed through solidification of sand deposited in a river channel and has subsequently been covered by other rock. A sandstone body of this type has a sinuous, unpredictable configuration.
Choke	A short, heavy steel pipe section having an orifice for restricting and controlling the flow of oil and gas. It is inserted in the flow stream at the wellhead or Christmas tree. There are two types: positive choke, having a fixed orifice; adjustable choke, having an adjustable orifice (needle point valve).
Christmas Tree	The assemblage of valves and fittings at the top of a completed well used in the control of production.
Circulation	Techniques for bringing cuttings from the bottom of the well bore to surface by continuously pumping drilling mud down through drill-string and up annulus during rotary drilling.
CO^2 Injection	A secondary recovery technique in which carbon dioxide (CO2) is injected into wells as part of a miscible recovery program.
Coalbed Methane (CBM)	Natural gas contained in coal deposits, whether or not stored in gaseous phase. Coalbed gas, although usually mostly methane, may be produced with variable amounts of inert or even non-inert gases. (Also termed Coal Seam Gas, CSG, or Natural Gas from Coal, NGC)
Cogeneration	An energy conversion system producing both electricity and process steam or steam for heating with a resultant overall improvement in conversion efficiency. It usually involves increasing the temperature and/or pressure of steam required for process use extracting part of the heat for electricity production and discharging the remainder at appropriate conditions for process requirements. Natural gas is a favoured fuel for combined cycle cogeneration units, in which waste heat is converted to electricity.
Coiled tubing	The use of coiled tubing string as a well-intervention method, the techniques offer several key benefits over alternative well-intervention as the company still is able to work under live well conditions.
Collar	A coupling device used to join two lengths of drilling pipe; heavy, thick walled pipe attached between the drilling string and the drilling bit to provide weight on the bit in order to improve its performance (also "drill collar").
Commercial	When a project is commercial, this implies that the essential social, environmental, and economic conditions are met, including political, legal, regulatory and contractual conditions. In addition, a project is commercial if the degree of commitment is such that the accumulation is expected to be developed and placed on production within a reasonable time frame. While five years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

Term	Definition
Committed project	Projects are committed only when it can be demonstrated that there is a firm intention to develop them and bring them to production. Intention may be demonstrated with funding/financial plans and declaration of commerciality based on realistic expectations of regulatory approvals and reasonable satisfaction of other conditions that would otherwise prevent the project from being developed and brought to production.
Completed	A well that is equipped and ready to produce following its drilling and testing.
Completion	Completion of a well. The process by which a well is brought to its final classification—basically dry hole, producer, injector, or monitor well. A dry hole is normally plugged and abandoned. A well deemed to be producible of petroleum, or used as an injector, is completed by establishing a connection between the reservoir(s) and the surface so that fluids can be produced from, or injected into, the reservoir. Various methods are utilized to establish this connection, but they commonly involve the installation of some combination of borehole equipment, casing and tubing, and surface injection or production facilities.
Completion interval	The specific reservoir interval(s) that is (are) open to the borehole and connected to the surface facilities for production or injection, or reservoir intervals open to the wellbore and each other for injection purposes.
Compressor	A device that raises the pressure of a compressible fluid, such as air or gas. Compressors create a pressure differential in order to move or compress a vapour or a gas, consuming power in the processing plant, and is used for water injection and recovery enhancement, or on pipeline transmission systems.
Concession	A grant of access for a defined area and time period that transfers certain entitlements to produced hydrocarbons from the host country to an enterprise. The enterprise is generally responsible for exploration, development, production, and sale of hydrocarbons that may be discovered. Typically granted under a legislated fiscal system where the host country collects taxes, fees, and sometimes royalty on profits earned.
Condensate	Condensates are a mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but when produced, are in the liquid phase at surface pressure and temperature conditions. Condensate differs from natural gas liquids (NGL) on two respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities; and (2) NGL includes very light hydrocarbons (ethane, propane, butanes) as well as the pentanes-plus that are the main constituents of condensate.
Conditions	The economic, marketing, legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated (also termed Contingencies).
Confidentiality agreement	An agreement pursuant to which proprietary information is granted to a party in exchange for similar information on, and/or concessions from, the party to whom access is granted.
Conglomerate	Coarse-grained clastic sedimentary rock with fragments larger than 2 mm in diameter.
Constant case	Modifier applied to project resources estimates and associated cash flows when such estimates are based on those conditions (including costs and product prices) that are fixed at a defined point in time (or period average) and are applied unchanged throughout the project life, other than those permitted contractually. In other words, no inflation or deflation adjustments are made to costs or revenues over the evaluation period.
Contingency	See Conditions.
Contingent project	Development and production of recoverable quantities has not been committed due to conditions that may or may not be fulfilled.
Contingent resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources.
Continuous-type deposit	A petroleum accumulation that is pervasive throughout a large area and which is not significantly affected by hydrodynamic influences. Such accumulations are included in Unconventional Resources. Examples of such deposits include "basin-centered" gas, shale gas, gas hydrates, natural bitumen and oil shale accumulations.
Conventional crude oil	Crude oil flowing naturally or capable of being pumped without further processing or dilution (see Crude Oil).
Conventional gas	Conventional gas is a natural gas occurring in a normal porous and permeable reservoir rock, either in the gaseous phase or dissolved in crude oil, and which technically can be produced by normal production practices.
Conventional resources	Conventional resources exist in discrete petroleum accumulations related to localized geological structural features and/or stratigraphic conditions, typically with each accumulation bounded by a downdip contact with an aquifer, and which is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water.
Conveyance	Certain transactions that are in substance borrowings repayable in cash or its equivalent and shall be accounted for as borrowings and may not qualify for the recognition and reporting of oil and gas reserves.
Core	Cylindrical sample of rock taken from a formation while drilling for purposes of examination and analysis.

Term	Definition
Core analysis	A study of the core in a laboratory to determine the following properties of the formation from which the core was taken: porosity, permeability, fluid content, angle of dip, geological age, lithology, and probable productivity, etc.
Core properties	A group of properties which are considered central to a company's operation.
Cost recovery	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor recovers costs (investments and operating expenses) out of the gross production stream. The contractor normally receives payment in oil production and is exposed to both technical and market risks.
Cracking	A process in which the feedstock is subjected to a high temperature for a limited time with the object of increasing the yield of light products, i.e.: gasoline, at the expense of the heavier products.
Crude oil	Crude oil is the portion of petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of pressure and temperature. Crude oil may include small amounts of non-hydrocarbons produced with the liquids but does not include liquids obtained from the processing of natural gas.
Crown	The government in the right of Canada or of a province.
Crown lease	The agreement held with the Crown which provides for the exploration and development of the petroleum and natural gas rights.
Crown royalty	A royalty based on production paid to a provincial government on all producing Crown leases.
Crude oil (heavy)	Crude oil will be deemed to be heavy crude oil if it has a density of ~900 kg/m^3 or more and API gravity 10-22.3 degrees.
Crude oil (light-medium)	Crude oil will be deemed to be light-medium crude oil if it has a density of less than 900 kg/m3. Medium oil has an API gravity of 22.3-31.1 degrees. Light oil has an API gravity of more than 31.1 degrees. An oil with an API gravity of less than 10 degrees (that is, with a density of more than 1,000 kilograms/cubic metre) is commonly referred to as bitumen.
Crude oil equivalent	Converting gas volumes to the oil equivalent is customarily done on the basis of the nominal heating content or calorific value of the fuel. There are a number of methodologies in common use. Before aggregating, the gas volumes first must be converted to the same temperature and pressure. Common industry gas conversion factors usually range between 1 barrel of oil equivalent (BOE) = 5,600 standard cubic feet (scf) of gas to 1 BOE = 6,000 scf. (Many operators use 1 BOE = 5,620 scf derived from the metric unit equivalent 1 m^3 crude oil = 1,000 m^3 natural gas). (Also termed barrels of oil equivalent.)
Cumulative production	The sum of production of oil and gas to date (see also Production).
Current economic conditions	Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve a defined averaging period. The SPE guidelines recommend that a one-year historical average of costs and prices should be used as the default basis of “constant case” resources estimates and associated project cash flows.
Cushion Gas Volume	With respect to underground natural gas storage, Cushion Gas Volume (CGV) is the gas volume required in a storage field for reservoir management purposes and to maintain adequate minimum storage pressure for meeting working gas volume delivery with the required withdrawal profile. In caverns, the cushion gas volume is also required for stability reasons. The cushion gas volume may consist of recoverable and non-recoverable in-situ gas volumes and injected gas volumes.
Cuttings	Rock chips cut by the drilling bit and obtained from a well during drilling operations at the surface over the "shale shaker."
Cycling of gas	Returning to a well the gas removed with the oil, thereby maintaining pressure in the reservoir and promoting more efficient recovery.
Daily Contract Quantity (DCQ)	The daily quantity of gas which the supplier agrees to furnish and for which the buyer agrees to pay, under a specific contract.
Darcy	A permeability unit based upon the passage of one square centimetre in one second under a pressure differential of one atmosphere.
Decline rate	The rate at which a well's production declines due to natural and sometimes man-introduced forces. Expressed in percent per unit of time.
Dedicated reserves	Natural gas supply under contract to a pipeline company.
Deep cut	Refers to the operation of a stripping plant where all natural gas liquids (NGLs) in a gas stream are recovered including ethane. Ethane is left in the gas stream in a shallow cut.
Delineation well	Drilled at a distance from a discovery well to determine physical extent, reserves, and likely production rate of a new oil or gas field.

Term	Definition
Deliverability	The volume of gas or oil a well, field, pipeline, or distribution system can supply at a particular pressure for a 24-hour period. Also refers to available capacity on a pipeline's ability to move gas from producing fields to market.
Depletion	Refers to the consumption of natural resources which are part of a company's assets. Producing oil, mining, and gas companies deal in products that cannot be replenished and as such are known as "wasting assets". The recording of depletion is a bookkeeping entry similar to depreciation and does not involve the expenditure of cash. Depletion is the amount charged to expense in the company's financial statements which relates to depletable assets that have been capitalized. This is not the earned depletion allowance calculated for income tax purposes.
Deposit	Material laid down by a natural process. In resource evaluations, it identifies an accumulation of hydrocarbons in a reservoir (see Accumulation).
Derrick	Load-bearing, tower-like framework over an oil or gas well which holds the hoisting and lowering equipment used to drill a well.
Derrick floor	The floor, or platform, upon which the drilling crew works and the rotary table is located.
Deterministic estimate	The method of estimation of Reserves or Resources is called deterministic if a discrete estimate(s) is made based on known geoscience, engineering, and economic data.
Developed reserves	Developed Reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered "developed" only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are also those expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Development not viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Development pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Development plan	The design specifications, timing and cost estimates of the development project including, but not limited to, well locations, completion techniques, drilling methods, processing facilities, transportation, and marketing. (See also Project.)
Development Unclarified or On Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Development well	Well drilled for oil or gas to a known producing formation within a proven field or area for the purpose of completing the designed pattern of production.
Deviated hole	A well which is not vertical, either by design or accident.
Dew point	The temperature at which vapour starts to condense.
Diamond core barrel	A hollow pipe studded with diamonds at its cutting end attached to a drilling string to obtain rock cores.
Dip	The amount and direction of the slope of subsurface rock beds or formations.
Directional drilling	A drilling operation in which the well is intentionally diverted from a vertical through the use of whipstocks. The rig is placed as near the location as possible and the hole is drilled at an angle to the petroleum-bearing formation.
Discovered	A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons. In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. (See also Known Accumulation)

Term	Definition
Discovered Petroleum Initially-in-Place	Discovered Petroleum Initially-in-Place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. Discovered Petroleum Initially-in-Place may be subdivided into Commercial, Sub-Commercial, and Unrecoverable, with the estimated commercially recoverable portion being classified as Reserves and the estimated sub-commercial recoverable portion being classified as Contingent Resources.
Discovery well	The first oil or gas well drilled in a new field; the well that reveals the presence of a petroleum-bearing reservoir. Subsequent wells are development wells.
Disposal gas	Gas in a crude oil solution.
Disposal well	A well used for disposal of salt water. Usually located in a subsurface formation sealed off from other formations.
Dissolved gas drive	Reservoir drive associated with pressure released by gas coming out of petroleum solution.
Doghouse	Small building located on or nearby the rig floor, used as an office for the driller and as a storage place for small tools and equipment.
Down time	When rig operations are temporarily suspended to effect repairs, for maintenance or for waiting on supplies.
Down-dip well	A well located low on a geological structure which may provide clues to oil and gas trapping higher on the structure.
Downstream segment	Includes refining, marketing, transportation and petrochemical operations.
Drainage	Migration of oil toward a well due to a reduction in pressure caused by the production of the well. In Alberta, the standard drainage area is commonly 640 acres for gas, 160 acres for oil (subject to down spacing).
Drill bit	An attachment to the end of the drill string, consisting of three conical heads. Rotation of the string during drilling rotates the toothed heads as well, and cuts the rock.
Drill collar (rotary):	Hollow, heavy steel bars placed directly about the drilling bit to keep the drill pipe in tension.
Drill pipe	Steel pipe, usually in 9.14 meter or 30 foot lengths, screwed together to form a continuous pipe extension from the drilling rig to the drilling bit at the bottom of the hole. Rotation of the drill pipe and bit causes the bit to bore through the rock.
Drill stem test	Conventional method of testing a formation to determine its potential productivity before installing production casing in a well. A testing tool is attached to the bottom of the drill pipe and placed opposite the formation to be tested which has been isolated by placing packers above and below the formation. Fluids in the formation are allowed to flow up through the drill pipe, enabling measurement of the rate and volume of the flow as well as sampling of fluids at the surface.
Drilled & Abandoned (D&A)	Drilled and abandoned is a term used to describe a well that is found to be dry, then plugged and abandoned.
Driller	An employee directly in charge of a particular crew as opposed to a toolpusher who is in charge of all crews on a rig. Operations of drilling and hoisting equipment constitute his main duties.
Drilling Fluid (“mud”)	Liquid, usually composed of clay, chemicals, and water, which is circulated through the well bore during rotary drilling. Rock cuttings from the bottom of the well bore are brought to the surface in the drilling fluid, which is also called “mud”. The composition and pressure of the drilling fluid helps control down-hole pressures. Drilling fluid also lubricates the bit and drill string.
Drilling program	An integrated schedule of drilling parameters to most effectively drill an oil well.
Drilling rate	The time required for rotary drilling to penetrate a rock formation.
Drillship	A marine vessel with an attached drilling rig, typically designed to operate in deep water. The drillship uses anchors and thrusters to remain stationary on location.
Drillstring	A combination of the drillpipe, bottomhole assembly and any other tools used to make the drill bit turn at the bottom of the wellbore.
Dry Hole	A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.
Economic	In relation to petroleum Reserves and Resources, economic refers to the situation where the income from an operation exceeds the expenses involved in, or attributable to, that operation.
Economic interest	An Economic interest is possessed in every case in which an investor has acquired any interest in mineral in place and secures, by any form of legal relationship, revenue derived from the extraction of the mineral to which he must look for a return of his capital.
Economic limit	Economic limit is defined as the production rate beyond which the net operating cash flows (after royalties or share of production owing to others) from a project, which may be an individual well, lease, or entire field, are negative.

Term	Definition
Edmonton par	Edmonton city gate price benchmark based on "light sweet" crude, as posted by major refiners.
Effective porosity	The percent of a rock volume in which the pore spaces are connected to fluid flow.
Electric log	A recording of the types of rocks, amount of porosity, and hydrocarbon or water content in a well as measured by an electrical instrument run in the well on a wire line. A typical log looks like a "brain-wave" recorded on long folded paper.
Enhanced Oil Recovery (EOR)	The process of stimulating the flow of oil to the well bore through various methods such as waterflood, heat or steam injection, etc. as a means to increase the recoverable reserves of a producing oil pool.
Entitlement	That portion of future production (and thus resources) legally accruing to a lessee or contractor under the terms of the development and production contract with a lessor.
Entity	Entity is a legal construct capable of bearing legal rights and obligations. In resources evaluations this typically refers to the lessee or contractor, which is some form of legal corporation (or consortium of corporations). In a broader sense, an entity can be an organization of any form and may include governments or their agencies.
Equipping	Preparation of a well for production. Equipment typically includes such items as a pump-jack, bottom-hole pump, motor, rods, storage tanks, and valves and fittings.
Estimated Ultimate Recovery (EUR)	Those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced there from.
Evaluation	The geosciences, engineering, and associated studies, including economic analyses, conducted on a petroleum exploration, development, or producing project resulting in estimates of the quantities that can be recovered and sold and the associated cash flow under defined forward conditions. Projects are classified and estimates of derived quantities are categorized according to applicable guidelines. (Also termed Assessment.)
Evaluator	The person or group of persons responsible for performing an evaluation of a project. These may be employees of the entities that have an economic interest in the project or independent consultants contracted for reviews and audits. In all cases, the entity accepting the evaluation takes responsibility for the results, including Reserves and Resources and attributed value estimates.
Exploration	The initial phase in petroleum operations that searches for prospects or plays through Geological and Geophysical surveys that may be followed by exploration drilling.
Exploration costs	Include all lease fees and land acquisition costs, geological and geophysical expenditures, and exploratory drilling costs whether capitalized or expensed. Exploratory drilling is generally defined as the drilling of a well outside a proved area, or within a proven area but to a previously untested zone, in order to determine whether oil or gas reserves exist. Also included are costs of dry wells, casing and other materials and equipment abandoned in place.
Exploratory well	An exploratory well is a well drilled in unproven territory to determine the presence of an oil or gas deposit in commercial quantities. Also called a "wildcat".
Farm-in	When one company drills wells or performs other activity on another company's lease in order to earn an interest in or acquire that lease.
Farm-out	An arrangement under which a portion of an interest in petroleum and natural gas rights is assigned in consideration for the assignee agreeing to explore or drill (and perhaps equip) one well or several wells at his sole expense; subsequent development and equipment costs, if any, and income and operating expenses are shared by the participant on an agreed basis. In its broadest sense, the term includes any arrangement wherein an owner agrees to dilute his interest in a property.
Fee lands	Privately owned, non-public lands.
Feedstock	Raw materials supplied to a refinery or petrochemical plant.
Field	An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both. The term may be defined differently by individual regulatory authorities.
Fishing	Various operations attempting to retrieve from the wellbore sections of drill pipe or other items (the 'fish') which may have broken off or been dropped into the hole.
Fishing tools	Special instruments equipped with the means for recovering the objects lost while drilling the well.
Five spot	The burning of unwanted gas as a means of disposing of it during completion operations, or if there is no market or other use for it.
Flare gas	Total volume of gas vented or burned as part of production and processing operations.
Flow tank	A tank in which the oil is run from the well and in which the gas and water may separate from the oil when the separator is not used.

Term	Definition
Flow test	An operation on a well designed to demonstrate the existence of moveable petroleum in a reservoir by establishing flow to the surface and/or to provide an indication of the potential productivity of that reservoir (such as a wireline formation test).
Flow through shares	Shares issued by the company with a specific provision that the associated funds will be spent on specified activities and any income tax deductions available as a result of such expenditures will be deductible by the shareholder for income tax purposes rather than the company.
Flowing well	A well that produces oil and/or gas by natural energy without any form of artificial lift.
Fluid contacts	The surface or interface in a reservoir separating two regions characterized by predominant differences in fluid saturations. Because of capillary and other phenomena, fluid saturation change is not necessarily abrupt or complete, nor is the surface necessarily horizontal.
Flush production	High rate of oil or gas production in the early life of a new well. The term is particularly applicable to new wells completed in low permeability reservoirs where there is a fairly rapid decline in productive capacity the first few months or so while the bottom-hole pressure is in a transient condition.
Forecast case	Modifier applied to project resources estimates and associated cash flow when such estimates are based on those conditions (including costs and product price schedules) forecast by the evaluator to reasonably exist throughout the life of the project. Inflation or deflation adjustments are made to costs and revenues over the evaluation period.
Formation	Sedimentary bed or deposit composed substantially of the same minerals throughout and distinctive enough to be a unit.
Forward sales	There are a variety of forms of transactions that involve the advance of funds to the owner of an interest in an oil and gas property in exchange for the right to receive the cash proceeds of production, or the production itself, arising from the future operation of the property. In such transactions, the owner almost invariably has a future performance obligation, the outcome of which is uncertain to some degree. Determination as to whether the transaction represents a sale or financing rests on the particular circumstances of each case.
Fracture (mineralogy)	How a mineral breaks; can be diagnostic physical property.
Fracture (stress)	Stress-induced breaks in rock material occurring in conjugate sets.
Fracture (fracing)	Method of stimulating production by increasing the permeability of the producing formation. The pressure causes cracks to open in the formation. Propping agents (such as sand grains, aluminum pellets) are carried in suspension by the fluid into the cracks. When pressure is released at the surface, the fracturing fluid returns, leaving the propping agent in formation. The cracks partially close on the propping agent, providing channels for oil or gas to flow through toward the well bore.
Freehold lease	An agreement with an individual which provides for the petroleum and natural gas rights underlying a given area.
Freehold royalty	A royalty based on production paid to the owner (anyone other than the Crown) of the producing lease.
Fuel gas	See Lease fuel.
Full cost method	A method of accounting for oil and gas properties, plant and equipment whereby costs relating to the acquisition, exploration and development of reserves are capitalized including the costs associated with unsuccessful projects.
Gas	Natural petroleum hydrocarbon in vapor or gas form. Also, Raw gas or marketable gas or any constituent of raw gas, condensate, crude bitumen, or crude oil that is recovered in processing and that is gaseous at the conditions under which its volume is measured or estimated
Gas balance	In gas production operations involving multiple working interest owners, an imbalance in gas deliveries can occur. These imbalances must be monitored over time and eventually balanced in accordance with accepted accounting procedures.
Gas cap gas	Gas cap gas is a free natural gas which overlies and is in contact with crude oil in the reservoir. It is a subset of associated gas.
Gas contract	A contract between a producer of natural gas and a marketer of natural gas for produced volumes and pipeline transportation space over a period of time.
Gas hydrates	Gas hydrates are naturally occurring crystalline substances composed of water and gas, in which a solid water lattice accommodates gas molecules in a cage-like structure, or clathrate. At conditions of standard temperature and pressure (STP), one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas. Because of this large gas-storage capacity, gas hydrates are thought to represent an important future source of natural gas. Gas hydrates are included in unconventional resources, but the technology to support commercial production has yet to be developed.
Gas injection	The pumping of gas into a petroleum reservoir to maintain or re-establish its pressure to increase production.

Term	Definition
Gas inventory	With respect to underground natural gas storage, “gas inventory” is the sum of working gas volume and cushion gas volume.
Gas/oil ratio	Gas to oil ratio in an oil field is calculated using measured natural gas and crude oil volumes at stated conditions. The gas/oil ratio may be the solution gas/oil ratio (Rs), the produced gas/oil ratio (Rp), or another suitably defined ratio of gas production to oil production.
Gas plant products	Gas plant products are natural gas liquids (or components) recovered from natural gas in gas processing plants and, in some situations, from field facilities. Gas plant products include ethane, propane, butanes, butanes/propane mixtures, natural gasoline and plant condensates, sulphur, carbon dioxide, nitrogen, and helium.
Gas seep	Where gas escapes from ground surface exposures of a reservoir.
Gas show	A gas indication in well cuttings.
Gas (Solution)	Gas that is dissolved in crude oil under reservoir conditions and evolves as a result of pressure and temperature changes.
Gas-oil contact	The interface between gas and underlying oil in a trap.
Gas-to-Liquids (GTL) projects	Gas-to-Liquids projects use specialized processing to convert natural gas into liquid petroleum products. Typically, these projects are applied to large gas accumulations where lack of adequate infrastructure or local markets would make conventional natural gas development projects uneconomic.
Gas-water contact	The interface between gas and underlying water in a trap in the absence of oil.
Gathering system	A gathering system is generally a series of pipes in a proven oil or gas field through which oil or gas from various wells flows into a main line or processing facility.
Geology	The study of the Earth—its history, structure, composition, life forms, and the processes that continue to change it.
Geophysics	Branch of science that applies physical principles to the study of Earth. It plays a critical role in the industry as data is used by company personnel to make predictions about the presence, nature, and size of subsurface hydrocarbon accumulations.
Geophysicist	A scientist whose expertise is in the acquisition of geophysical measurements of the Earth's crust either through seismic, magnetic, or gravity methods.
Geostatistical methods	A variety of mathematical techniques and processes dealing with the collection, methods, analysis, interpretation, and presentation of masses of geoscience and engineering data to (mathematically) describe the variability and uncertainties within any reservoir unit or pool, specifically related here to resources estimates, including the definition of (all) well and reservoir parameters in 1, 2, and 3 dimensions and the resultant modeling and potential prediction of various aspects of performance.
Gigajoule (GJ)	A measure of energy content of a fuel; a typical residential consumer of natural gas might use about 130 gigajoules (GJ) per year for household heating.
Gusher	A well drilled into a formation in which the crude is under such high pressure that it first spurts out of the wellhead like a geyser. Gushers are rare today owing to improved drilling technology and the use of drilling mud to control downhole pressure.
Henry Hub	A pipeline interchange near Erath, LA where eight interstate and three intrastate pipelines interconnect. The point of exchange for natural gas futures contracts.
High Estimate	With respect to resource categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.
Horizon	1. (geological) A plane of stratification assumed to have originally been horizontal. 2. (soil) A layer of soil distinguished by characteristic physical properties by letters (for example A horizon, B horizon, C horizon).
Horizontal drilling (Directional drilling)	Term used to describe a well where the departure of the wellbore from the vertical exceeds ~80 degrees. Horizontal wells are able to penetrate a greater length of the reservoir and can offer significant production improvements over a vertical well.
Hydrocarbons	Hydrocarbons are chemical compounds consisting wholly of hydrogen and carbon.
Improved Recovery (IR)	Improved Recovery is the extraction of additional petroleum, beyond Primary Recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called Enhanced Recovery.)
Infill drilling	Wells drilled to fill in between established producing wells to increase production, thereby reducing spacing between wells.

Term	Definition
Initial potential (IP)	The production rate reported on the initial completion of a well. This is usually the result of a production test made at the time of completion or shortly thereafter and reported as the amount of oil and gas produced per day under stated flowing or pumping conditions as applicable. The reported information may or may not reflect the capacity of the well. In the case of gas wells, the theoretical capacity is reported as the open flow potential.
Injection	The forcing, pumping, or free flow under vacuum, of substances into a porous and permeable subsurface rock formation. Injected substances can include either gases or liquids.
Injection well	A well used to inject any fluid or gas for pressure maintenance, storage, disposal, or secondary recovery into an underground reservoir.
Jackup rig	A drilling rig situated on a floating barge and fitted with long support legs that can be raised or lowered independently. The rig is floated to the drilling location and the legs are jacked down which raises the barge and drilling structure above the water.
Justified for development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting and that there are reasonable expectations that all necessary approvals/contracts will be obtained. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Kerogen	The naturally occurring, solid, insoluble organic material that occurs in source rocks and can yield oil upon heating. Kerogen is also defined as the fraction of large chemical aggregates in sedimentary organic matter that is insoluble in solvents (in contrast, the fraction that is soluble in organic solvents is called bitumen). (See also Oil Shales.)
Kick	Occurs when the pressure encountered in a formation exceeds the pressure exerted by the column on drilling mud circulating through the hole. If uncontrolled, a kick leads to a blowout.
Known accumulation	An accumulation is an individual body of petroleum-in-place. The key requirement to consider an accumulation as "known," and hence containing Reserves or Contingent Resources, is that it must have been discovered, that is, penetrated by a well that has established through testing, sampling, or logging the existence of a significant quantity of recoverable hydrocarbons.
Land sale	The sale of oil and gas rights by the Crown.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Lease	Rights held by agreement to explore for, develop and take petroleum and/or natural gas for a fixed term and so long thereafter as production shall continue, subject to payment or reservation of a royalty, or other consideration.
Lease condensate	Lease condensate is condensate recovered from produced natural gas in gas/liquid separators or field facilities.
Lease fuel	Oil and/or gas used for field and processing plant operations. For consistency, quantities consumed as lease fuel should be treated as shrinkage. However, regulatory guidelines may allow lease fuel to be included in Reserves estimates. Where claimed as Reserves, such fuel quantities should be reported separately from sales, and their value must be included as an operating expense.
Lease plant	A general term referring to processing facilities that are dedicated to one or more development projects and the petroleum is processed without prior custody transfer from the owners of the extraction project (for gas projects, also termed "Local Gas Plant").
Lease rental payments	Lease rental payments to the lessor by the lessee in order to retain a lease. A lease can be surrendered by simply not making the annual payment. Lease rental payments on Crown leases must continue to be paid even after production begins.
Lessee	The individual or company who negotiates a petroleum and natural gas lease with the beneficial owner of the right.
Lessor	The beneficial owner of petroleum and natural gas rights underlying a given area.
Liner	Small diameter casing extending into producing layer from just inside the bottom of final string of casing cemented in a well.
Liquefied Natural Gas (LNG) project	Liquefied Natural Gas projects use specialized cryogenic processing to convert natural gas into liquid form for tanker transport. LNG is about 1/164 the volume of natural gas at standard temperature and pressure.
Loan agreement	A loan agreement is typically used by a bank, other investor, or partner to finance all or part of an oil and gas project. Compensation for funds advanced is limited to a specified interest rate.
Log	A continuous vertical recording of natural or induced electrical, radioactive or sonic impulses of the formations which can be interpreted to ascertain rock type, porosity, permeability, and fluid content in varying degrees of accuracy.

Term	Definition
Looping	Paralleling an existing pipeline by another line to increase capacity.
Lost circulation, lost returns	An interruption in the circulation of drilling mud caused by the mud entering a porous zone, fracture, or cavity such that the mud fails to return to the surface.
Low/Best/High estimates	The range of uncertainty reflects a reasonable range of estimated potentially recoverable volumes at varying degrees of uncertainty (using the cumulative scenario approach) for an individual accumulation or a project.
Low estimate	With respect to resource categorization, this is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
Lowest known hydrocarbons	The deepest occurrence of a producible hydrocarbon accumulation as interpreted from well log, flow test, pressure measurement, or core data.
LPG (liquefied petroleum gases)	Hydrocarbon fractions lighter than gasoline, such as ethane, propane and butane, kept in a liquid state through compression and/or refrigeration, commonly referred to as “bottled gas.”
M^3	A cubic meter – metric measurement for volumes of crude oil or natural gas.
Marginal contingent resources	Known (discovered) accumulations for which a development project(s) has been evaluated as economic or reasonably expected to become economic but commitment is withheld because of one or more contingencies (e.g., lack of market and/or infrastructure).
Marginal well	An oil or gas well, the production of which is so limited in relation to production costs, that profit approaches the vanishing point.
Marketable gas	Raw gas from which natural gas liquids and non-hydrocarbon gases have been removed or partially removed by processing. Marketable gas is also known as “pipeline quality gas” or “sales gas”, and it is composed primarily of methane.
Marketer	A company that buys or resells gas or brokers it for a profit. Marketers usually perform a variety of related services associated with moving gas to their customers. This would include arranging transportation, monitoring deliveries, and load balancing.
MCF	The metric unit of measure is the cubic meter. 1 MCF = 28.174 cm^3. MMCF=1,000 MCF. BCF = 1,000 MMCF .
Measurement	The process of establishing quantity (volume or mass) and quality of petroleum products delivered to a reference point under conditions defined by delivery contract or regulatory authorities.
Mineral interest	Mineral interests in properties including (1) a fee ownership or lease, concession, or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest; (2) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and (3) those agreements with foreign governments or authorities under which a reporting entity participates in the operation of the related properties or otherwise serves as producer of the underlying reserves (as opposed to being an independent purchaser, broker, dealer, or importer).
Monte Carlo Simulation	A type of stochastic mathematical simulation that randomly and repeatedly samples input distributions (e.g., reservoir properties) to generate a resulting distribution (e.g., recoverable petroleum volumes).
Mud	A fluid used in drilling to remove cuttings from the hole, it also cools and lubricates the drilling bit and controls underground formation pressures while drilling.
Mud log	A progressive analysis of the well-bore cuttings washed from the borehole by the drilling mud.
Mud pump	Equipment for circulating drilling mud.
Mud tank	Storage tank for drilling mud.
Muskeg	Wet, marshy, poorly drained forested flat lands of Northern Canada; can normally only be accessed in winter when the muskeg is frozen.
Natural bitumen	Natural bitumen is the portion of petroleum that exists in the semisolid or solid phase in natural deposits. In its natural state, it usually contains sulphur, metals, and other non-hydrocarbons. Natural bitumen has a viscosity greater than 10,000 milliPascals per second (mPa.s) (or centipoises) measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural viscous state, it is not normally recoverable at commercial rates through a well and requires the implementation of improved recovery methods such as steam injection. Natural bitumen generally requires upgrading prior to normal refining. (Also called crude bitumen.)
Natural gas	Natural gas is the portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in natural underground reservoirs, and which is gaseous at atmospheric conditions of pressure and temperature. Natural gas may include some amount of non-hydrocarbons.
Natural gas inventory	With respect to underground natural gas storage operations “inventory” is the total of working and cushion gas volumes.

Term	Definition
Natural Gas Liquids	Natural Gas Liquids (NGL) are a mixture of light hydrocarbons that exist in the gaseous phase and are recovered as liquids in gas processing plants. NGL differs from condensate in two principal respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGL includes very light hydrocarbons (ethane, propane, butanes) as well as the pentanes-plus that are the main constituents of condensates.
Natural Gas Liquids to Gas Ratio	Natural gas liquids to gas ratio in an oil or gas field, calculated using measured natural gas liquids and gas volumes at stated conditions.
Natural gas plant	Is the plant in which the hydrogen sulphide and other undesirable contents are removed through chemical and other processes. In addition to gas sweetening in the gas plant, the recovery of other products, such as propane, butane, sulphur and natural gas is made possible. Also known as gas plant.
Net-back	Linkage of input resource to the market price of the refined products.
Net pay	The vertical thickness of the productive rock in a reservoir.
Net profits interest	An interest that receives a portion of the net proceeds from a well, typically after all costs have been paid.
Net working interest	A company's working interest reduced by royalties or share of production owing to others under applicable lease and fiscal terms. (Also called net revenue interest.)
Non-hydrocarbon gas	Natural occurring associated gases such as nitrogen, carbon dioxide, hydrogen sulphide, and helium. If non-hydrocarbon gases are present, the reported volumes should reflect the condition of the gas at the point of sale. Correspondingly, the accounts will reflect the value of the gas product at the point of sale.
Non-associated gas	Non-associated gas is a natural gas found in a natural reservoir that does not contain crude oil.
Normal production practices	Production practices that involve flow of fluids through wells to surface facilities that involve only physical separation of fluids and, if necessary, solids. Wells can be stimulated, using techniques including, but not limited to, hydraulic fracturing, acidization, various other chemical treatments, and thermal methods, and they can be artificially lifted (e.g., with pumps or gas lift). Transportation methods can include mixing with diluents to enable flow, as well as conventional methods of compression or pumping. Practices that involve chemical reforming of molecules of the produced fluids are considered manufacturing processes.
O/W contact	Oil/water contact. Oil, being lighter than water, will rest upon it in subsurface trap. The O/W contact can be detected on logs.
Offset well location	Potential drill location adjacent to an existing well. The offset distance may be governed by well spacing regulations. In the absence of well spacing regulations, technical analysis of drainage areas may be used to define the spacing. For Proved volumes to be assigned to an offset well location there must be conclusive, unambiguous technical data which supports the reasonable certainty of production of hydrocarbon volumes and sufficient legal acreage to economically justify the development without going below the shallower of the fluid contact or the lowest known hydrocarbon.
Oil sands	Sand deposits highly saturated with natural bitumen. Also called "Tar Sands." Note that in deposits such as the Western Canadian "oil sands," significant quantities of natural bitumen may be hosted in a range of lithologies including siltstones and carbonates.
Oil seep	An exposure of an oil reservoir or conduit where oil emerges at the ground surface.
Oil shales	Shale, siltstone, and marl deposits highly saturated with kerogen. Whether extracted by mining or in situ processes, the material must be extensively processed to yield a marketable product (synthetic crude oil).
Oil show	An indication of oil in well cuttings.
Oilfield	A loosely defined term referring to an area where oil is found. May also include the oil reservoir, the surface and wells, and production equipment.
On production	The development project is currently producing and selling petroleum to market. A project status/maturity sub-class that reflects the actions required to move a project toward commercial production.
Open hole	An uncased well bore.
Operator	The company or individual responsible for managing an exploration, development, or production operation.
Outcrop	A ground surface expression of a geologic structure or formation. A portion of bedrock or other stratum protruding through the soil level, indicating a fault or some other oil-bearing formation.
Overlift/Underlift	Production overlift or underlift can occur in annual records because of the necessity for companies to lift their entitlement in parcel sizes to suit the available shipping schedules as agreed among the parties. At any given financial year-end, a company may be in overlift or underlift. Based on the production matching the company's accounts, production should be reported in accord with and equal to the liftings actually made by the company during the year, and not on the production entitlement for the year.

Term	Definition
Overriding royalty	A cost free interest in the production from a well over and above the government's or landowner's royalty.
Payout	The time when all of the costs incurred in drilling a well (or project) have been paid back out of the net operating revenue from a well (or project). Most farm in/farm out agreements contain a payout conversion clause; at payout, the farmer has the right to convert his overriding royalty to a working interest.
Penetration	The intersection of a wellbore with a reservoir.
Perforate	To pierce holes though well casing with an oil or gas bearing formation by means of a perforating gun lowered down the hole and fired electrically from the surface. The perforation permits production from a formation.
Permeability	The measurement of a rock's ability to transmit fluids. Formations that transmit fluid readily are described as permeable and tend to have many large, well connected pores. Impermeable formations such as shale and siltstones tend to be finer grained with smaller/fewer interconnected pores.
Petroleum	Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbon compounds, common examples of which are carbon dioxide, nitrogen, hydrogen sulphide, and sulphur. In rare cases, non-hydrocarbon content could be greater than 50%.
Petroleum Initially-in-Place	Petroleum Initially-in-Place is the total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs. Crude Oil-in-Place, Natural Gas-in-Place and Natural Bitumen-in-Place are defined in the same manner (see Resources). (Also referred as Total Resource Base or Hydrocarbon Endowment.)
Pig	A scraping device that is sent down the pipeline with the oil and gas to clean the inside of the pipeline of waxy build up.
Pilot project	A small-scale test or trial operation that is used to assess the suitability of a method for commercial application.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Pool	An individual and separate accumulation of petroleum in a reservoir.
Pooling	Pooling is the joining of small tracts of land for the purpose of allowing a well permit to be granted under applicable spacing rules.
Pore space	The spaces within a rock body that are unoccupied by solid material. Pore spaces include space between grains, fractures, vesicles, and voids formed by dissolution.
Porosity	The property of rock to contain holes or openings and to contain fluids. It is commonly expressed as a percentage of the rock occupied by these openings. Twenty percent porosity means that 20% of the volume of the rock is made up of holes.
Possible Reserves	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.
Primary porosity	Sediment or particle porosity at a time of deposition.
Primary recovery	Primary recovery is the extraction of petroleum from reservoirs utilizing only the natural energy available in the reservoirs to move fluids through the reservoir rock to other points of recovery.
Probability	The extent to which an event is likely to occur, measured by the ratio of the favourable cases to the whole number of cases possible. SPE convention is to quote cumulative probability of exceeding or equalling a quantity where P90 is the small estimate and P10 is the large estimate. (See also Uncertainty.)
Probabilistic estimate	The method of estimation of Resources is called probabilistic when the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities.
Probable Reserves	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
Processing	The action of removing impurities and by-products from a producing stream.
Producing capacity	The estimated production level that could be achieved, unrestricted by demand, but restricted by reservoir performance, well density and well capacity, oil sands mining capacity, field processing, and pipeline capacity.

Term	Definition
Producing horizon	Where the well is actually produced, since it may be drilled to a much greater depth.
Producing well	A producing well is a well that produces oil or gas.
Production	Production is the cumulative quantity of petroleum that has been actually recovered over a defined time period. While all recoverable resource estimates and production are reported in terms of the sales product specifications, raw production quantities (sales and non-sales, including non-hydrocarbons) are also measured to support engineering analyses requiring reservoir voidage calculations.
Production test	A test made to determine the daily rate of oil, gas, and water production from a potential pay zone.
Production-sharing contract	In a production-sharing contract between a contractor and a host government, the contractor typically bears all risk and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the opportunity to recover the incurred investment from production, subject to specific limits and terms. Ownership is retained by the host government; however, the contractor normally receives title to the prescribed share of the volumes as they are produced.
Profit split	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor is entitled to a share of the remaining profit oil or gas. The contractor receives payment in oil or gas production and is exposed to both technical and market risks.
Project	Represents the link between the petroleum accumulation and the decision-making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, or an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership. In general, an individual project will represent a specific maturity level at which a decision is made on whether or not to proceed (i.e., spend money), and there should be an associated range of estimated recoverable resources for that project. (See also Development Plan.)
Propane	A flammable gaseous paraffin hydrocarbon, C_3H_8 found in crude petroleum and natural gas and is used as a fuel.
Property	A volume of the Earth's crust wherein a corporate entity or individual has contractual rights to extract, process, and market a defined portion of specified in-place minerals (including petroleum). Defined in general as an area but may have depth and/or stratigraphic constraints. May also be termed a lease, concession, or license.
Prorationing	The allocation of production among reservoirs and wells or allocation of pipeline capacity among shippers, etc.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target. A project maturity sub-class that reflects the actions required to move a project toward commercial production.
Prospective resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
Proved Economic	In many cases, external regulatory reporting and/or financing requires that, even if only the Proved Reserves estimate for the project is actually recovered, the project will still meet minimum economic criteria; the project is then termed as "Proved Economic."
Proved Reserves	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Proved Reserves are those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. Often referred to as 1P, also as "Proven."
Purchase contracts	A contract to purchase oil and gas provides the right to purchase a specified volume of production at an agreed price for a defined term.
Pure-service contract	A pure-service contract is an agreement between a contractor and a host government that typically covers a defined technical service to be provided or completed during a specific period of time. The service company investment is typically limited to the value of equipment, tools, and expenses for personnel used to perform the service. In most cases, the service contractor's reimbursement is fixed by the terms of the contract with little exposure to either project performance or market factors.
Range of uncertainty	The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. (See Resource categories.)
Raw natural gas	Raw natural gas is natural gas as it is produced from the reservoir. It includes water vapour and varying amounts of the heavier hydrocarbons that may liquefy in lease facilities or gas plants and may also contain sulphur compounds such as hydrogen sulphide and other non-hydrocarbon gases such as carbon dioxide, nitrogen, or helium, but which, nevertheless, is exploitable for its hydrocarbon content. Raw natural gas is often not suitable for direct utilization by most types of consumers.

Term	Definition
Reasonable certainty	If deterministic methods for estimating recoverable resource quantities are used, then reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered.
Reasonable expectation	Indicates a high degree of confidence (low risk of failure) that the project will proceed with commercial development or the referenced event will occur.
Reasonable forecast	Indicates a high degree of confidence in predictions of future events and commercial conditions. The basis of such forecasts includes, but is not limited to, analysis of historical records and published global economic models.
Reclamation	The process of reconverting disturbed land to its former state or other productive uses.
Re-completion	Work on a well to re-complete it in a different formation, either deeper or shallower than originally completed. (See workover for the distinction.)
Recoverable Resources	Those quantities of hydrocarbons that are estimated to be producible from discovered or undiscovered accumulations.
Recoveries	Dollar amounts received by a company to compensate for expenses incurred for operating a property or managing a project.
Recovery (pools)	In gas pools, the fraction of the in-place reserves of gas expected to be recovered under the subsisting recovery mechanism.
Recovery efficiency	A numeric expression of that portion of in-place quantities of petroleum estimated to be recoverable by specific processes or projects, most often represented as a percentage.
Recovery factor	The expected fraction or percentage of original oil-in-place that will be recovered under certain conditions.
Reference point	A defined location within a petroleum extraction and processing operation where quantities of produced product are measured under defined conditions prior to custody transfer (or consumption). Also called Point of Sale or Custody Transfer Point.
Refining	Manufacturing petroleum products by a series of processes that separate crude oil into its major components and blend or convert these components into a wide range or finished products, such as gasoline or jet fuel.
Re-injection	Product that is produced from a given well is injected to increase or maintain flow rates.
Relief well	A well drilled in a high-pressure formation to control a blow-out.
Renewals	Most petroleum and natural gas leases, both Crown and Freehold, make provision under certain circumstances for their continuation following the expiration of its primary term of the lease. Where a lease is continued beyond the expiration of its primary term, it is often said to be renewed and in some instances, a new lease would be issued and this would be a renewal of the original lease.
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: They must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.
Reservoir	A subsurface rock formation containing an individual and separate natural accumulation of moveable petroleum that is confined by impermeable rocks/formations and is characterized by a single-pressure system.
Reservoir pressure	Pressure in a subsurface petroleum-bearing rock, due to overburden thickness, deformation, fluid column, etc.
Resources	The term “resources” as used herein is intended to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the Earth’s crust, discovered and undiscovered, plus those quantities already produced. Further, it includes all types of petroleum whether currently considered “conventional” or “unconventional” (see Total Petroleum Initially-in-Place). (In basin potential studies, it may be referred to as Total Resource Base or Hydrocarbon Endowment.)
Resources categories	Subdivisions of estimates of resources to be recovered by a project(s) to indicate the associated degrees of uncertainty. Categories reflect uncertainties in the total petroleum remaining within the accumulation (in-place resources), that portion of the in-place petroleum that can be recovered by applying a defined development project or projects, and variations in the conditions that may impact commercial development (e.g., market availability, contractual changes)
Resources classes	Subdivisions of Resources that indicate the relative maturity of the development projects being applied to yield the recoverable quantity estimates. Project maturity may be indicated qualitatively by allocation to classes and sub-classes and/or quantitatively by associating a project’s estimated chance of reaching producing status.
Revenue-sharing contract	Revenue-sharing contracts are very similar to the production-sharing contracts described earlier, with the exception of contractor payment. With these contracts, the contractor usually receives a defined share of revenue rather than a share of the production.
Reversionary interest	The right of future possession of an interest in a property when a specified condition has been met.

Term	Definition
Rig	The derrick, draw-works and attendant surface equipment of a drilling or workover unit.
Risk	The probability of loss or failure. As “risk” is generally associated with the negative outcome, the term “chance” is preferred for general usage to describe the probability of a discrete event occurring.
Risk and reward	Risk and reward associated with oil and gas production activities stems primarily from the variation in revenues due to technical and economic risks. Technical risk affects a company’s ability to physically extract and recover hydrocarbons and is usually dependent on a number of technical parameters. Economic risk is a function of the success of a project and is critically dependent on cost, price, and political or other economic factors.
Risk factor	Oil and gas projects are assigned a “risk factor” based on their chance of success using parameters such as the geological and geophysical interpretation.
Risked-service contract	These agreements are very similar to the production-sharing agreements with the exception of contractor payment, but risk is borne by the contractor. With a risked-service contract, the contractor usually receives a defined share of revenue rather than a share of the production.
Road ban	Travel restriction imposed on secondary, non-surfaced roads during break-up, usually April or May each year.
Rotary drilling	Method of drilling in which the drill pipe is rotated in order to rotate the bit
Rotary table	Equipment over the wellbore which transfers power from the engines to produce a rotary motion. Via bushings and gears, the rotary motion is transferred to the kelly and through to the drilling string.
Roughneck	A worker on a drilling rig or workover rig, subordinate to the driller.
Round trip	Pulling drill pipe from the hole to change the bit, then running the drill pipe and new bit back in the hole.
Royalty	Royalty refers to payments that are due to the host government or mineral owner (lessor) in return for depletion of the reservoirs and the producer (lessee/contractor) for having access to the petroleum resources. Many agreements allow for the producer to lift the royalty volumes, sell them on behalf of the royalty owner, and pay the proceeds to the owner. Some agreements provide for the royalty to be taken only in kind by the royalty owner.
Sales	The quantity of petroleum product delivered at the custody transfer (reference point) with specifications and measurement conditions as defined in the sales contract and/or by regulatory authorities. All recoverable resources are estimated in terms of the product sales quantity measurements.
Sedimentary rock	Rock formed by the accumulation and consolidation of sediment.
Seismic	A geophysical exploration method based on the measurement of wave fronts propagated by dynamic explosions or other sound generations for the mapping of subsurface geologic structures.
Seismic Surveys	Measurements of seismic-wave travel. Seismic exploration is divided into refraction and reflection surveys, depending on whether the predominant portion of the seismic waves’ travel is horizontal or vertical. Refraction seismic surveys are used in exploration. Seismic reflection surveys detect boundaries between different kinds of rocks; this detection assists in mapping of geologic structures.
Semisubmersible	A type of offshore drilling vessel which floats on large pontoon structures submerged below the sea surface and are anchored to the sea floor. Semisubmersibles can operate in deep water.
Separator	A pressure vessel used to separate well fluids into gasses and liquids.
Service well	A well drilled in a known oil or natural gas field to inject liquids that enhance recovery or dispose of salt water.
Shooting	The term “shooting” is used in connection with geophysical work to describe the process of exploding charges of dynamite at various locations and observing its effect with seismographic instruments for the purpose of discovering the nature of the underlying formations.
Show	An indication of oil or gas in well cuttings, drilling mud, or core.
Shut-down well	A term denoting a well on which work has been temporarily stopped.
Shut-in capacity	Unused productive capacity of currently producing oil or gas which, for some reason, is not on production.
Shut-in Reserves	Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate, but which have not started producing; (2) wells which were shut-in for market conditions or pipeline connections; or (3) wells not capable of production for mechanical reasons.
Sidetracking	Drilling another well next to a nonproducing well and using the upper part of the non producer. This is one way to drill past obstructions in a well.
Solution gas	Solution gas is a natural gas which is dissolved in crude oil in the reservoir at the prevailing reservoir conditions of pressure and temperature. It is a subset of associated gas.

Term	Definition
Sour crude	Oil that contains significant amounts of hydrogen sulphide and must be treated to remove the sulphur before it can be used.
Sour natural gas	Sour natural gas is a natural gas that contains sulphur, sulphur compounds, and/or carbon dioxide in quantities that may require removal for sales or effective use.
Sour rocks	Rocks rich in organic material, such as black waxy shales, thought to have "soured" the oil and gas which have since migrated into the reservoir rocks.
Spacing unit	The minimum area on any given prospect on which a well will be drilled. It represents the area of the reservoir in which that well will drain (usually 160 acres for oil, 640 acres for gas).
Specific gravity	The ratio of the density of a substance to the density of water.
Spud	Commencement of the actual drilling of a well. (Sequence of events: rigging up, spudding, drilling ahead or making hole, reaching total depth, testing, completion.)
Spud date	The date that the bit first touches the ground in the drilling operation.
Step-out well	A step-out well is a well drilled adjacent to a proven well but located in an unproven area in an effort to ascertain the extent and boundaries of a producing formation.
Stimulation	The descriptive term used for several processes to enlarge old channels, or create new ones, in the producing formation of a well, i.e. acidizing, fracturing, or explosive treatments.
Stochastic	Adjective defining a process involving or containing a random variable or variables or involving chance or probability such as a stochastic stimulation.
Straddle plant	A natural gas processing plant within the pipeline transmission system, at which point gas is further processed (subsequent to field processing) to remove additional natural gas liquids. This plant "straddles" the main pipeline. In Canada, most ethane is produced at straddle plants. Also known as a reprocessing plant.
Stratification	The layered structure of sedimentary rock.
Stripper	An oil well that yields 10 or fewer barrels of oil per day, or a gas well that produces an average of less than 60,000 cubic feet per day, measured over a 90-day period.
Structural trap	A petroleum trap formed by deformation.
Sub-Commercial	A project is Sub-Commercial if the degree of commitment is such that the accumulation is not expected to be developed and placed on production within a reasonable time frame. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual/strategic objectives. Discovered sub-commercial projects are classified as contingent resources.
Sub-Marginal contingent resources	Known (discovered) accumulations for which evaluation of development project(s) indicated they would not meet economic criteria, even considering reasonably expected improvements in conditions.
Submersible drilling rig (submersibles)	A drilling rig used in relatively shallow offshore drilling locations. The rig is floated to location, where the drilling platform is lowered onto the sea floor while the operating deck sits above the waves.
Surface casing	First string of casing set in well.
Sweet crude	Crude oil with low sulphur content which is less corrosive, burns cleaner, and requires less processing to yield valuable products.
Sweet natural gas	Sweet natural gas is a natural gas that contains no sulphur or sulphur compounds at all, or in such small quantities that no processing is necessary for their removal in order that the gas may be sold.
Synthetic Crude Oil (SCO)	A mixture of hydrocarbons derived by upgrading (i.e., chemically altering) natural bitumen from oil sands, kerogen from oil shales, or processing of other substances such as natural gas or coal. SCO may contain sulphur or other non-hydrocarbon compounds and has many similarities to crude oil.
Take-or-pay	The amount of gas a buyer must either take or pay for now and take delivery in the future.
Tar	Thick, viscous petroleum.
Taxes	Obligatory contributions to the public funds, levied on persons, property, or income by governmental authority.
Technical uncertainty	Indication of the varying degrees of uncertainty in estimates of recoverable quantities influenced by the range of potential in-place hydrocarbon resources within the reservoir and the range of the recovery efficiency of the recovery project being applied.
Three-dimensional (3-D) Seismic	3-D images are created by bouncing sound waves off underground rock formations; It is used to determine best places to drill for hydrocarbons.

Term	Definition
Throughput	A term used to describe the total amount of raw materials that are processed by a plant such as an oil refinery in a given period.
Thrust fault	A fault in which the older rock formations have moved over the younger formations.
Tight formations	A zone of low permeability and thus low well productivity. Wells in such zones usually require fracturing or other stimulation. Typically, the productive capacity of a new well completed in a tight zone declines rapidly for several months or longer after completion.
Tight hole	Information on the drilling and completion of a well is kept secret by the operator.
Toll	A tax or charge levied on those who use a particular service. The charge to transport hydrocarbons from a receipt point to a delivery point.
Total depth (TD)	The greatest depth reached in the well.
Total Petroleum Initially-in-Place	Total Petroleum Initially-in-Place is generally accepted to be all those estimated quantities of petroleum contained in the subsurface, as well as those quantities already produced. This was defined previously by the WPC as "Petroleum-in-Place" and has been termed "Resource Base" by others. Also termed "Original-in-Place" or "Hydrocarbon Endowment."
Trap	A geological feature in which petroleum can accumulate.
Uncertainty	The range of possible outcomes in a series of estimates. For recoverable resource assessments, the range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities for an individual accumulation or a project. (See also Probability.)
Unconventional resources	Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (also called "continuous-type deposits"). Examples include coalbed methane (CBM), basin-centered gas, shale gas, gas hydrate, natural bitumen (tar sands), and oil shale deposits. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, massive fracturing programs for shale gas, steam and/or solvents to mobilize bitumen for in-situ recovery, and, in some cases, mining activities). Moreover, the extracted petroleum may require significant processing prior to sale (e.g., bitumen upgraders). (Also termed "Non-Conventional" Resources and "Continuous Deposits.")
Undeveloped land	Land owned by a company which, to date, has no proven or probable reserves and may have dry holes on it.
Undeveloped Reserves	Undeveloped Reserves are quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.
Unit operator	The oil company in charge of development and production in an oil field in which several companies have joined together to produce the field.
Unitization	Process whereby owners group adjoining properties and divide reserves, production, costs, and other factors according to their respective entitlement to petroleum quantities to be recovered from shared reservoir(s).
Unproved Reserves	Unproved Reserves are based on geoscience and/or engineering data similar to that used in estimates of Proved Reserves, but technical or other uncertainties preclude such reserves being classified as Proved. Unproved Reserves may be further categorized as Probable Reserves and Possible Reserves.
Unrecoverable Resources	That portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which are estimated, as of a given date, not to be recoverable. A portion of these quantities may become recoverable in the future as commercial circumstances change, technological developments occur, or additional data is acquired.
Upgrader	General term applied to processing plants that convert extra-heavy crude oil and natural bitumen into lighter crude and less viscous synthetic crude oil (SCO). While the detailed process varies, the underlying concept is to remove carbon through coking or to increase hydrogen by hydrogenation processes using catalysts.
Viscosity	A measure of the quality of an oil – its resistance to flow. Low viscosity oil has naturally higher recovery factors than high viscosity (i.e. heavy) oils.
Water drive	Natural energy derived from water encroachment into an oil or gas reservoir moving oil or gas producing wells. Encroachment may come from the edge or bottom.
Water encroachment	The invasion of water into an oil or gas zone displacing oil or gas toward producing wells.
Waterflood	The increase in recovery from a pool through replacement of produced fluid with water. A pattern is usually formed with injection wells surrounded by producing wells. This process re-pressures the reservoir and displaces oil otherwise unrecoverable to producers.
Water injection	Pumping of water into a reservoir to establish production pressure.

Term	Definition
Well abandonment	The permanent plugging of a dry hole, an injection well, an exploration well, or a well that no longer produces petroleum or is no longer capable of producing petroleum profitably. Several steps are involved in the abandonment of a well: permission for abandonment and procedural requirements are secured from official agencies; the casing is removed and salvaged if possible; and one or more cement plugs and/or mud are placed in the borehole to prevent migration of fluids between the different formations penetrated by the borehole. In some cases, wells may be temporarily abandoned where operations are suspended for extended periods pending future conversions to other applications (i.e. reservoir monitoring, enhanced recovery, etc.)
Well bore	The three-dimensional, circular perforation that results from drilling a well.
Well program	The procedure for drilling, casing, and completing a well.
Well spacing	Regulation or specification of acres per well and distance between wells as a conservation or economic measure.
Wet gas	Wet (rich) gas is natural gas from which no liquids have been removed prior to the reference point. The wet gas is accounted for in resource assessments, and there is no separate accounting for contained liquids. It should be recognized that this is a resource assessment definition and not a phase behaviour definition.
Wildcat	A well drilled in unproved territory.
Wild well	A well whose flow has not been brought under control.
Working Gas Volume (WGV)	With respect to underground natural gas storage, Working Gas Volume (WGV) is the volume of gas in storage above the designed level of cushion gas which can be withdrawn/injected with the installed subsurface and surface facilities (wells, flowlines, etc.) subject to legal and technical limitations (pressures, velocities, etc.). Depending on local site conditions (injection/withdrawal rates, utilization hours, etc.), the working gas volume may be cycled more than once a year.
Working interest	A company's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.
Workover	Remedial operations on a well with the hope of restoring or increasing production from the same zone; includes such work as plugging back, squeeze cementing, re-perforating, clean-out, acidizing, etc. A workover to re-complete in another formation is called a recompletion.
Zone	A specific interval of rock strata containing one of more reservoirs, used interchangeably with formation.

Source: © 2003-2009 Society of Petroleum Engineers (SPE), the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), The Society of Petroleum Evaluation Engineers (SPEE) Petroleum Resources Management System document, and Ayrton Exploration Consulting Ltd.

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