

COMPTON

PETROLEUM CORPORATION

**ANNUAL INFORMATION FORM
For the Year Ended December 31, 2007**

March 25, 2008

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ABBREVIATIONS AND CONVERSION FACTORS

Abbreviations

The following are abbreviations of technical terms used throughout this Annual Information Form:

“**bbbl**” means barrel;

“**bbbl/d**” means barrels per day;

“**bbls**” means barrels;

“**boe**” means barrels of crude oil equivalent;

“**boepd**” or “**boe/d**” means barrels of crude oil equivalent per day;

“**km²**” means square kilometres;

“**lt**” means long ton;

“**Mbbls**” means thousand barrels;

“**Mboe**” means thousand barrels of crude oil equivalent;

“**Mcf**” means thousand cubic feet;

“**Mcfe**” means thousand cubic feet equivalent;

“**mi**” means miles;

“**mi²**” means square miles;

“**Mlt**” means thousands of long tons;

“**MMbbls**” means million barrels;

“**MMBoe**” means million barrels of crude oil equivalent;

“**MMbtu**” means million British thermal units;

“**MMcf**” means million cubic feet;

“**MMcfd**” or “**MMcf/d**” means million cubic feet per day;

“**MMcfe**” means million cubic feet equivalent; and

“**ngls**” means natural gas liquids.

Conversion Factors

To conform with common usage, Standard Imperial Units of measurement are used in this Annual Information Form to describe exploration and production activities. The following table sets forth conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
boe	Mcfe	6.000
cubic feet	cubic metres of gas	0.028
cubic metres of gas	cubic feet	35.490
bbls of oil	cubic metres	0.159
cubic metres	bbls of oil	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.400
hectares	acres	2.500

DEFINITIONS

The following terms, when used in this Annual Information Form, have the following meanings and, where applicable, are as set forth in National Instrument 51-101, “Standards of Disclosure for Oil and Gas Activities,” issued by the Canadian Securities Administrators (“CSA”).

“**associated gas**” means the gas cap overlying a crude oil accumulation in a reservoir.

“**Company**” or “**Compton**” or “**we**” means Compton Petroleum Corporation and its partnership and subsidiaries where the context so requires.

“**crude oil**” or “**oil**” means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain small amounts of sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir, and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids.

“**developed non-producing**” reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

“**developed producing**” reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production and the date of resumption of production must be known with reasonable certainty.

“development costs” means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering, and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;
- (b) drill and equip development wells, development type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly;
- (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices, production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
- (d) provide improved recovery systems.

“development well” means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

“EUB” means the Alberta Energy and Utilities Board.

“exploration costs” means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as “prospecting costs”) and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

- (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies (collectively sometimes referred to as “geological and geophysical costs”);
- (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
- (c) dry hole contributions and bottom hole contributions;
- (d) costs of drilling and equipping exploratory wells; and
- (e) costs of drilling exploratory type stratigraphic test wells.

“exploratory well” means a well that is not a development well, a service well, or a stratigraphic test well.

“field” means 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 impervious strata or laterally by local geologic barriers or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to denote localized geological features, in contrast to broader terms such as “basin,” “trend,” “province,” “play,” or “area of interest”.

“forecast prices and costs” means future prices and costs that are:

- (a) generally accepted as being a reasonable outlook of the future; and
- (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

“future income tax expenses” means future income tax expenses estimated year-by-year:

- (a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;
- (b) without deducting estimated future costs that are not deductible in computing taxable income;
- (c) taking into account estimated tax credits and allowances; and
- (d) applying to the future, pre-tax cash flows relating to the Company’s oil and gas activities and the appropriate year end statutory tax rates, taking into account future tax rates already legislated.

“future net revenue” means the estimated net amount to be received with respect to the development and production of reserves estimated using forecast prices and costs.

“gross” means:

- (a) in relation to the Company’s interest in production or reserves, its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company;
- (b) in relation to wells, the total number of wells in which the Company has an interest; and
- (c) in relation to properties, the total area of properties in which the Company has an interest.

“liquids” means crude oil, natural gas liquids, and sulphur.

“**natural gas**” or “**gas**” means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases, but which may contain natural gas liquids. Natural gas can exist in a reservoir either dissolved in crude oil (solution gas) or in a gaseous phase (associated gas or non-associated gas). Non-hydrocarbon substances may include hydrogen sulphide, carbon dioxide, and nitrogen.

“**natural gas liquids**” means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate, and small quantities of non-hydrocarbons.

“**net**” means:

- (a) in relation to the Company’s interest in production or reserves, its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;
- (b) in relation to the Company’s interest in wells, the number of wells obtained by aggregating the Company’s working interest in each of its gross wells; and
- (c) in relation to the Company’s interest in a property, the total area of properties in which the Company has an interest multiplied by the working interest owned by the Company.

“**non-associated gas**” means an accumulation of natural gas in a reservoir where there is no crude oil.

“**operating costs**” or “**production costs**” means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

“**probable**” reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

“**production**” means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

“**property**” includes:

- (a) fee ownership or a lease, concession, agreement, permit, licence, 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;
- (b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and
- (c) an agreement with a foreign government or authority under which the Company participates in the operation of properties or otherwise serves as producer of the underlying reserves (in contrast to being an independent purchaser, broker, dealer, or importer).

A property does not include supply agreements or contracts that represent a right to purchase, rather than extract, oil or gas.

“property acquisition costs” means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property) including:

- (a) costs of lease bonuses and options to purchase or lease a property;
- (b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee; and
- (c) brokers’ fees, recording and registration fees, legal costs, and other costs incurred in acquiring properties.

“proved” reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

“proved property” means a property or part of a property to which reserves have been specifically attributed.

“reserves” are estimated remaining quantities of oil and natural gas, and related substances anticipated to be recoverable from known accumulations, as of a given date, based on (a) analysis of drilling, geological, geophysical and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

“reservoir” means a porous and permeable subsurface rock formation that contains a separate accumulation of petroleum that is confined by impermeable rock or water barriers and is characterized by a single pressure system.

“section” means one square mile or 640 acres.

“service well” means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane, or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

“shut-in well” means a well which is capable of economic production or which the Company considers capable of production but which for a variety of reasons, including, but not limited to, lack of markets or development, is not placed on production at the present time.

“solution gas” means gas dissolved in crude oil.

“stratigraphic test well” means a geologically directed drilling effort, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) “exploratory type” if not drilled into a proved property; or (b) “development type”, if drilled into a proved property. Development type stratigraphic wells are also referred to as “evaluation wells”.

“support equipment and facilities” means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps and division, district, or field offices.

“undeveloped” reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g. when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, possible) to which they are assigned.

“unproved property” means a property or part of a property to which no reserves have been specifically attributed.

“well abandonment costs” means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. Costs of abandoning the gathering system or reclaiming the wellsite are not included.

ADVISORIES

Use of BOE Equivalents

The oil and natural gas industry commonly expresses production volumes and reserves on a barrel of oil equivalent (“boe”) basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil, ngl, and natural gas measurement units into one basis for improved measurement of results and comparisons with other industry participants. In several sections that follow, Compton has used the 6:1 boe measure which is the approximate energy equivalency of the two commodities at the burner tip and does not represent a value equivalency at the wellhead. However, boes do not represent a value equivalency at the plant gate where Compton sells its production volumes and therefore may be a misleading measure if used in isolation.

Forward Looking Statements

Certain information regarding the Company contained herein constitutes forward looking information and statements under the meaning of applicable securities laws, including Canadian Securities Administrators’ National Instrument 51-102 Continuous Disclosure Obligations and the United States Private Securities Litigation Reform Act of 1995. Forward looking statements include assumptions, estimates, plans, expectations, opinions, forecasts, projections, guidance, or other statements that are not statements of fact, including statements regarding (i) cash flow, 2008 production estimates, reserve estimates, capital expenditures, operating expenditures, 2008 drilling program, tax estimates, total future net revenue, pricing assumptions, abandonment and reclamation costs, and (ii) other risks and uncertainties described from time to time in the reports and filings made by Compton with securities regulatory authorities. Although Compton believes that the expectations and assumptions reflected in such forward looking statements are reasonable, it can give no assurance that such assumptions and expectations will prove to have been correct. There are many factors that could cause forward looking statements not to be correct, including risks and uncertainties inherent in the Company’s business. These risks include, but are not limited to: crude oil and natural gas price volatility, exchange rate fluctuations, availability of services and supplies, operating hazards, access difficulties and mechanical failures, weather related issues, uncertainties in the estimates of reserves and in projection of future rates of production and timing of development expenditures, general economic conditions, and the actions or inactions of third-party operators, and other risks set forth in the “Risk Factors” section of this Annual Information Form. Statements relating to “reserves” or “resources” are deemed to be forward-looking statements, as they involve the implied assessment, based on estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future. Compton may, as considered necessary in the circumstances, update or revise forward looking information, whether as a result of new information, future events, or otherwise, but Compton does not undertake to update this information at any particular time, except as required by law. The Company’s

forward looking statements are expressly qualified in their entirety by this cautionary statement. Compton cautions readers that the forward-looking statements may not be appropriate for purposes other than their intended purposes and that undue reliance should not be placed on any forward-looking statement.

CORPORATE STRUCTURE

Name and Incorporation

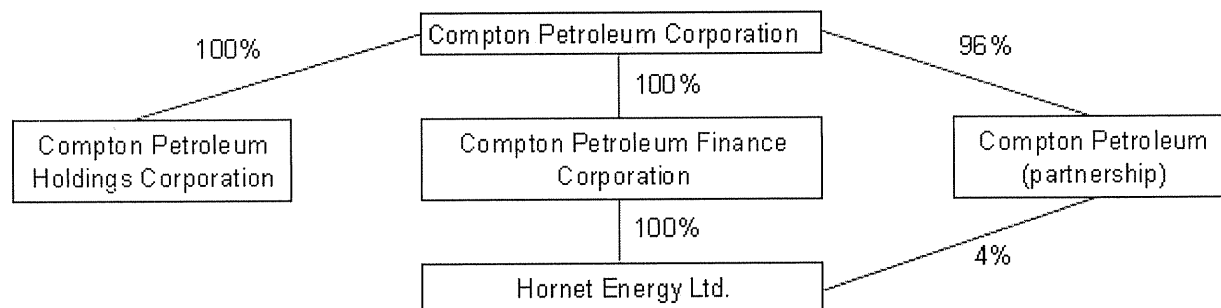
Compton was incorporated by articles of incorporation pursuant to the provisions of the *Business Corporations Act (Alberta)* (the “**ABCA**”) on October 15, 1992, as 544201 Alberta Ltd. The articles were amended on April 13, 1993, to change the Company’s name to Compton Petroleum Corporation and the Company commenced active business operations in July 1993. The articles were amended on November 21, 1994 and March 1, 1996, in order to remove the private company restrictions contained in the articles. A further amendment was made to the articles on September 1, 1998, in order to create a class of preferred shares issuable in series.

The Company’s head and principal office is located at Suite 3300, 425-1st Street S.W., Fifth Avenue Place, East Tower, Calgary, Alberta, Canada, T2P 3L8. Compton’s registered office is located at Suite 3000, 237-4th Avenue, S.W., Fifth Avenue Place, West Tower, Calgary, Alberta, Canada, T2P 4X7.

Effective January 31, 2001, a general partnership called Compton Petroleum was formed under the laws of Alberta. Compton Petroleum Corporation and Hornet Energy Ltd., a wholly-owned subsidiary of Compton Petroleum Finance Corporation, are the partners of the partnership. The majority of our production activities are carried out through this partnership.

Compton Petroleum Finance Corporation, formed under the laws of Alberta, is a wholly-owned subsidiary of Compton Petroleum Corporation. Compton Petroleum Finance Corporation has no independent operations and has no significant liabilities or assets other than US\$450 million of 7½% Senior Notes issued by Compton Petroleum Finance Corporation, its equity interest in Hornet Energy Ltd. and intercorporate indebtedness. The registered office of Compton Petroleum Finance Corporation is 4300 Bankers Hall West, 888 – 3rd Street S.W., Calgary, Alberta, Canada, T2P 5C5.

Compton Petroleum Holdings Corporation, formed under the laws of Alberta, is a wholly-owned subsidiary of Compton Petroleum Corporation. Compton Petroleum Holdings Corporation has no independent operations and has no significant liabilities or assets other than owning US\$158,250,000 aggregate principal amount of 9.90% Notes issued by Compton Petroleum Corporation and intercorporate indebtedness. The registered office of Compton Petroleum Holdings Corporation is 4300 Bankers Hall West, 888 – 3rd Street S.W., Calgary, Alberta, Canada, T2P 5C5.



The consolidated financial statements include the accounts of Compton Petroleum Corporation and all of its subsidiaries and partnerships.

GENERAL DEVELOPMENT OF THE BUSINESS

Compton is an Alberta based independent public company actively engaged in the exploration, development, and production of natural gas, ngls, and crude oil in the Western Canada Sedimentary Basin (the “WCSB”) in Canada. Compton commenced operations in 1993 with \$1 million of share capital, a small dedicated technical team, and a large seismic database. The objective was to build a company through internal, full cycle exploration, complemented by strategic acquisitions. Compton’s goal was to create a company capable of long term sustained growth with a primary focus on natural gas. Compton’s focus and strategy have remained unchanged since conception. Compton’s shares are listed on the Toronto Stock Exchange under the symbol CMT and on the New York Stock Exchange under the symbol CMZ.

Three Year History

In 2005, progress was made on each of the Company’s four resource plays including the Plains Belly River/Edmonton group which includes the Horseshoe Canyon coalbed methane, Basal Quartz at Hooker and thrust, Foothills Belly River at Callum in southern Alberta, and the Rock Creek/Gething play at Niton in central Alberta. The Company’s consolidated capital program of \$513 million included drilling 392 gross (334 net) wells with a 96% success rate. The drilling program resulted in an exit production rate of 35,500 boe/d and average production of 29,424 boe/d for the year. High commodity prices and increased production generated record revenue of \$564 million. Compton’s proved plus probable reserves totaled 207 MMBoe as at December 31, 2005. Approximately 62 MMBoe was added to the Company’s proved plus probable reserves through drilling successes, acquisitions, and extensions.

In 2006, continued progress was made on the development of each of the Company’s four resource plays. Compton’s consolidated capital program of \$526 million included drilling 342 gross (274 net) wells, replacing 348% of its 2006 production at an all-in finding, development, and acquisition cost of \$8.84/boe, excluding change in future capital, and \$13.56/boe, including change in future capital. The drilling program resulted in an average production rate of 33,187 boe/d for the year and total proved plus probable reserves increased 20% to 249 MMBoe as at December 31, 2006.

In 2007, Compton continued to achieve solid proved plus probable reserve additions at competitive finding and development costs in each of the Company’s core areas. Compton successfully completed a 322 well drilling program, replacing 192% of the Company’s 2007 production at an all-in FD&A of \$9.95/boe, excluding change in future capital, and \$12.86/boe, including change in future capital. Compton’s 2007 proved plus probable reserves grew by 9% to 271 MMBoe as at December 31, 2007. During the year, Compton pursued the strategy of divesting non-focus assets and the redeployment of the proceeds into the Company’s focus area natural gas plays. Compton closed non-core property divestments, including its conventional light oil property at Worsley, for total net proceeds of \$303.1 million. Compton also added to its core areas through a series of property acquisitions that totalled approximately \$73.7 million and completed two corporate acquisitions, Stylus Energy Inc. and WIN Energy Corporation, which significantly expanded its presence in southern Alberta and the Foothills at a total cost of \$131.4 million.

DESCRIPTION OF THE BUSINESS

Exploration and Production Operations

Compton's exploration, development and exploitation activities are concentrated principally in two core areas: 1) shallow gas resources play, targeting the Plains Belly River and overlying Edmonton Horseshoe Canyon zones, and 2) deep gas plays that include the Basal Quartz sands at Hooker, the Gething/Rock Creek sands at Niton and Caroline in central Alberta, and the Foothills stacked, thrust Upper Cretaceous Belly River play at Callum in the south. These areas are the geographic focus of Compton's seismic database and are areas in which Compton's management ("Management") and staff have significant technical expertise and operational experience.

Business Plan and Operating Strategy

The Company's business plan is to grow Compton's reserves and maximize production and cash flow from its core geographic areas and other areas where Compton has technical expertise. Management is implementing this objective by focusing on the efficient exploration, development, and exploitation of the Company's properties, controlling operating costs, adding economic reserves and production, and making strategic acquisitions in its core areas. Compton has experienced professional, management, technical, and support staff sufficient to carry out its business plan and its current exploration, exploitation, development, production, engineering, financial, and administrative functions.

The Company's operating strategy includes the components set forth below:

Concentrate on Core Areas. Compton is focused on its core areas, which provide a balanced portfolio of exploration, development, and exploitation prospects. These areas are the geographic focus of the Company's seismic database rights and are areas in which Management and staff have significant technical expertise and operational experience. Compton intends to generate exploration opportunities and to increase the Company's undeveloped land base within the WCSB.

Focus on Unconventional Natural Gas in Large Resource Plays. As of December 31, 2007, approximately 84% of proved reserves were natural gas. The Company has gained considerable technical expertise and achieved significant success in exploring for unconventional, larger natural gas accumulations in the WCSB. Compton plans to continue to focus on finding and developing these types of natural gas opportunities because of their generally lower decline curves and higher economic return over the life of the reserves compared to conventional natural gas opportunities. The large scale nature of the Company's resource plays also offers multiple low-risk drilling locations resulting in lower costs and decreased exploration risk.

Pursue Growth Through the Drill Bit Complemented by Selective Acquisitions. Compton plans to continue to reinvest internally generated cash flow and to use other sources of capital to fund the growth of the Company's exploration and development programs and to further increase its undeveloped land base to maintain a growing inventory of drilling prospects in core areas. Based on plans for an annual drilling program of 500 to 700 gross wells, the Company has over 10 years of drilling inventory on existing lands. Most of these planned wells are expected to be in close proximity to producing wells in existing core areas. Compton's drilling success rate has been at or above 90% for each of the past three years, evidencing the Company's ability to successfully grow reserves and production from its extensive inventory of drilling locations.

Control Infrastructure and Operatorship. Compton believes that control over gathering and processing infrastructure and operatorship of drilling programs will continue to be critical to the success of the Company's full-cycle exploration program. Compton currently owns or has access to critical infrastructure in each of its three core areas. Being an operator ensures discretion in determining the timing and methodology of ongoing exploration, development, and exploitation programs. Compton expects to continue to expand its working interest in core areas to maximize these operating efficiencies.

Maintain Financial Flexibility. The Company is committed to maintaining financial flexibility sufficient to allow it to pursue its full-cycle exploration program in periods of low commodity prices and to respond to opportunities for strategic acquisitions as they arise. Compton has historically funded its exploration, development, and exploitation capital program through internally generated cash flow and has financed acquisitions through bank debt, the issuance of common shares, or a combination thereof. The Company's accelerated drilling program has recently been, and will continue to be, funded through internally generated cash flow, the issuance of additional equity and debt, and non-core property sales. Other components of Compton's financial discipline include establishing appropriate leverage ratios and maintaining an active commodity hedging program.

Principal Properties

Compton engages in oil and gas exploration and development in the WCSB in Alberta, Canada. Compton's focus is on the Deep Basin portion of the Basin, which extends from Northwest Alberta and British Columbia to the United States border. In this large geographical region, Compton pursues two types of resource plays. A shallow gas resource play, targeting the Plains Belly River and overlying Edmonton Horseshoe Canyon zones, and the three deep gas plays that include the Basal Quartz sands at Hooker, the Gething/Rock Creek sands at Niton and Caroline in central Alberta, and the Foothills slacked, thrust Upper Cretaceous Belly River play at Callum in the south.

Shallow Gas

The Plains Belly River and overlying Edmonton Horseshoe Canyon shallow gas zones cover more than 1,200 sections of Compton held land in southern Alberta. The entire 900 metre gas-charged section is comprised of multiple Belly River sands, silts, shales, and coals, overlain by the Edmonton/Horseshoe Canyon coals that similarly include sands, silts, and shales. In 2007 Compton drilled a total of 226 wells through the Edmonton Horseshoe Canyon targeting the Belly River section. Going forward, Compton expects to focus on downspacing, development drilling, and recompletions in order to establish a resource manufacturing and processing model designed to maximize production.

Plains Belly River and Edmonton Coal Bed Methane

At December 31, 2007, Compton was producing approximately 55 mmcf/d from 630 Belly River and Edmonton coal bed methane wells. With 1,200 sections of land, at four wells per section automatic downspacing, this land base translates to a significant multi-year, low risk drilling inventory on which to grow the Company.

During 2007, Compton deployed a four well per section reduced spacing initiative for our Belly River drilling program. Wherever possible, Compton's shallow gas wells were drilled in batches in areas close to existing infrastructure. This initiative enabled Compton to significantly reduce Compton's 2007 spud to rig release and rig release to on-stream times to 2.8 days and 99 days, respectively. Drilling results at Compton's southern Alberta Belly River play were 100% successful in 2007, with particularly notable advances in the Brant, south Hooker, Ghost Pine, and Vulcan areas. Such success resulted from the use of

Compton's 1,200 km² of proprietary 3D seismic, coupled with detailed geological mapping, which allowed us to model the Belly River sands for consistent, repeatable success.

At Brant, Compton's 3-5-17-27W4M compressor station became fully operational in November 2007, providing Compton the requisite horsepower needed to bring on eight new wholly owned Belly River wells. These wells were producing a combined four mmcf/d at year end. The average production rate of these wells is approximately double the Company's 30 day initial production rate of a typical Belly River well. Compton's 2007 drilling targeted longer term producing wells such as Compton Brant 00/07-05-017-27W4M/0 and Compton Silver 00/13-32-016-28W4M/2. These two wells are producing 570 and 860 mcf/d, respectively as at year end. In 2008, Compton intends to follow up with similar drilling initiatives into south Hooker and south Brant.

In the Ghost Pine area, Compton expanded its 15-11-30-23W4M compressor station from eight to 12 mmcf/d in 2007. A total of 62 Belly River and Horse Shoe Canyon coal wells are currently producing 12 mmcf/d at Ghost Pine. Compton has 14 standing gas wells that are scheduled to be tied-in in the first quarter 2008, Compton has recently reprocessed its 3D seismic in this area, and in 2008 Compton plans to use this seismic to replicate the Ghost Pine Belly River gas well 02/07-10-030-23W4M, which had an initial production rate of 1,300 mcf/d, and the 00/05-01-030-23W4/4 Coal Bed Methane gas well, which had an initial production rate of 74 mcf/d.

Finally, further south in the Vulcan area, Compton placed five Belly River gas wells drilled by Stylus Energy Inc. on production in late 2007. In aggregate, these wells were placed on production at 2.2 mmcf/d. These wells are the southernmost Belly River gas wells producing in Alberta.

Compton's total compression capacity for southern Alberta low pressure gas was 95 mmcf/d as at December 31, 2007. Compton had 27,000 horsepower of installed compression dedicated to the plays installed and running at year end 2007.

In 2008, Compton plans to drill 275 Belly River wells, focusing specifically on the top tier prospects identified by its technical teams. Compton has allocated approximately \$180 million in its budget to this area, with \$5 million ear-marked specifically to continue with identification of well locations and licensing such that as industry conditions improve, Compton can readily ramp-up activity. Compton has estimated that approximately 40% of its 2008 Belly River wells drilled in the latter part of the year will not come on production until early 2009 and will, as a result, be eligible to take advantage of the lower shallow gas royalty rates effective in Alberta for 2009.

Compton's 2008 southern Alberta plans also include an eight well per section pilot project. Additionally and following on Compton's Deep Basin deeper target success as described below, Compton will use extended reach drilling with multi-stage fracturing techniques in the pilot project.

Deep Basin

Compton has two Deep Basin gas plays: the Basal Quartz sands at Hooker and the Gething/Rock Creek sands at Niton and Caroline in central Alberta.

Southern Alberta: Hooker

Discovered by Compton in 1999, the Basal Quartz sandstone pool at Hooker is the southern Alberta extension of the Lower Cretaceous Deep Basin gas trend. Current production extends over five townships, and in 2007, Compton drilled 10 wells at Hooker.

In March 2008, Compton successfully completed the first horizontal well in southern Alberta at Niton targeting the Basal Quartz formation utilizing multi-stage fracturing technology. The well at 9-17-17-29W4 was drilled with a 700 metre horizontal leg that flow tested at six mmcf/d and was tied-in shortly thereafter. A second horizontal well is expected to be drilled at 15-30-16-29W4 and 15 follow-up locations have been identified.

While Compton has been employing horizontal drilling and multi-stage frac technology in the Niton area in central Alberta with good success, the 9-17 well at Hooker is significant in that it establishes that this technology is applicable to the development of the Hooker Basal Quartz play in southern Alberta. To date the Hooker play has been developed through drilling one to two vertical wells per section. Reservoir modeling indicates up to four vertical wells per section may be necessary to fully develop the play. A horizontal well could replace two to three vertical wells, eliminating the need for extensive down-spacing in the area.

Central Alberta: Niton and Caroline

The Niton area in central Alberta, 150 miles west of Edmonton, is also in the Lower Cretaceous Deep Basin fairway. Compton's main targets are the Jurassic Rock Creek and Cretaceous Gething, analogous to the Hooker pool in southern Alberta. Proprietary exploration, development, and operational knowledge gained by the Company in southern Alberta has resulted in accelerated growth of this core area. In 2007, Compton drilled 35 wells at Niton and Caroline.

Compton experienced significant drilling success with Compton's Rock Creek horizontal gas well program at Niton in 2007. The average cost to drill and complete a Niton horizontal gas well is approximately \$4.5 million, or roughly two times the cost of a comparative vertical Rock Creek gas well. With a 30 day initial production average of 5.0 mmcfe/d per well, horizontal wells produce about four times that of a comparative vertical well. Compton's average horizontal gas well is 2,600 metres deep and has a 1,000 metre open-hole section. Multiple open-hole packers are set within the horizontal section and three to four staged hydraulic fractures are completed. At year end, Compton had eight Niton horizontal Rock Creek wells on production. Six of these wells were gas wells and two were oil wells. with the gas wells producing approximately 16.2 mmcfe/d in aggregate and the two oil wells producing a combined 153 boe/d.

To date in 2008 Compton has drilled two additional horizontal wells at Niton and a third well is being drilled in March 2008. The first well tested 3.0 mmcf/d and most recently, the well at 4-27-52-17W5 completed at the end of February 2008 flow tested at 11 mmcf/d. The third well is scheduled to be completed in March 2008. Production from these wells will be facility constrained pending the completion of additional compression and gathering lines. This work is scheduled for completion by the end of March 2008 barring any delay resulting from an early spring break-up. A total of 10 additional locations are planned for this area in 2008.

In 2008, Compton's Niton budget plans for 15 horizontal wells using this multi-stage frac technology. Last year's focus by a number of producers, including Compton, targeted the Compton discovered Edson Rock Creek P pool. Following the Niton Rock Creek successes, Compton posted and acquired a 100% interest in 12 sections of mineral rights on a second Rock Creek discovery. Late in 2007, Compton drilled Edson 00/01-31-052-16W5M/0 discovery well on this block of land. This well was successful and is currently producing at 3.5 mmcfe/d.

All major compression equipment has been ordered for this play, Compton plans to have eight 100% working interest horizontal wells on stream by the end of May 2008.

For 2008 Compton has allocated approximately \$135 million or 33% of its total planned capital expenditures to its central Alberta resource play. Compton plans to drill 48 wells in this area, with 13 of these wells slated to be horizontal. The 2008 plan is to continue to aggressively drill similar Rock Creek plays and to transfer this multi-staged horizontal fracture technology to other Compton-operated deep basin gas plays throughout Alberta.

Foothills

Compton's Callum/Cowley property consists of a series of over pressured, thrust, low permeability Belly River sands in the foothills of southern Alberta. A total of 15 exploratory wells have been drilled over the life of the play. Based on Compton's initial detailed geological, geophysical, and engineering analysis of seismic, cores, well logs, and test and production data, Callum appears to exhibit many similarities to the deep unconventional gas pools of the Rocky Mountain region of the United States.

In 2007, Compton drilled a horizontal well targeting a specific group of sands plus intersecting mapped fracture systems. The well came on production at approximately 6.5 mmcf/d, without stimulation. Further reservoir and completion work is planned on this well bore in 2008.

During the fourth quarter of 2007, Compton acquired WIN Energy Inc., a junior oil and gas company that was active on lands immediately adjacent to Compton's. This acquisition added 68,000 gross (53,600 net) acres of undeveloped land in the Cowley area in southern Alberta prospective for the thrust Belly River trend. As at December 31, 2007 Compton held approximately 239 net sections of high impact exploration lands at Callum and Cowley.

With Compton's acquisition of WIN Energy Inc., it also acquired 55 kilometres of 2D seismic and a new 36 square mile 3D seismic survey surrounding currently producing wells. Using this seismic data, Compton plans to replicate its recent horizontal well program at Callum in the Cowley area. In 2008, Compton plans to drill four extended reach horizontal wells. These wells will be oriented to intersect the maximum number of natural fractures in the foothills gas play. Each of these horizontal wells will use multi-stage fracturing techniques and will be drilled from existing pads to minimize our environmental impact. Compton plans to drill a total of nine wells in the Callum and Cowley area in 2008.

Compton treats the southern Alberta Foothills region as a unique environmental eco-system. In conjunction with a number of southern Alberta ranching operations, we are completing a rangeland health assessment that addresses optimal ways to restore these systems to their natural state. This includes funding of studies on native rough fescue grasses by the University of Alberta, as well as working closely with both industry and landowner work groups. Surface impact on all proposed wells are anticipated to be minimized by using existing drill pads or by selecting surface areas on sites previously disturbed by the agriculture industry.

Principal Markets and Distribution Methods

Compton's natural gas production is sold under a combination of longer term contracts with aggregators and short term daily or monthly indexed contracts. Approximately 10% of the Company's natural gas production in 2007 was committed to aggregators, compared to an average of 11% in 2006. The average aggregator price realized in 2007 was \$0.75/Mcf less than the non-aggregator prices realized during the year. Natural gas production is transported through regulated pipelines within Alberta, at tolls requiring government approval.

The Company's crude oil sales are priced at Edmonton postings and are typically sold on 30 day evergreen arrangements. Natural gas liquids are bid out on an annual basis to obtain the most favorable pricing. The Company sells crude oil and ngl's primarily to refineries and marketers of crude oil and natural gas liquids. Liquids may be transported through regulated pipelines or trucked to the point of sale.

Environmental Policies

Compton believes in the importance of protecting the environment. The Company is committed to conducting all operations in a safe manner that minimizes environmental impact, while meeting regulatory requirements and corporate standards. The Company maintains a comprehensive range of internal programs and controls to promote regulatory compliance and an appropriate level of safety and environmental protection across its operations. The Company's proactive program includes annual environmental compliance audit and inspection programs to ensure Compton's facilities continually meet or exceed regulatory standards. The Company has participated in programs for continual improvement set forth by the Canadian Association of Petroleum Producers, Energy Resources and Conservation Board, Alberta Environmental Protection, and other related associations, thus demonstrating Compton's commitment to minimizing the Company's environmental impact.

The Company carries out its activities in compliance with all relevant regulations and industry best practices. At present, the Company believes that it meets all existing environmental standards and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet current environmental protection requirements. The Company does not anticipate making extraordinary material expenditures for environmental compliance during 2008. However, it does expect to incur site restoration costs over a prolonged period as existing wells become fully produced. Compton provides for future abandonment and reclamation costs in its financial statements in accordance with Canadian generally accepted accounting principles.

Mazeppa Processing Partnership

In June of 2003, Mazeppa Processing Partnership ("MPP") acquired certain midstream assets from an independent third party. The assets consist of major natural gas gathering and processing facilities in Southern Alberta. Compton does not have an ownership position in MPP. Through a management agreement, Compton manages the activities of MPP and is therefore considered to be the primary beneficiary of MPP's operations. As a result, Compton consolidates the accounts of MPP for reporting purposes in accordance with the guidelines issued by the Accounting Standards Board, in Accounting Guideline AcG-15, "Consolidation of Variable Interest Entities." The results of the midstream activities are immaterial to Compton's consolidated financial condition.

Employees

As at December 31, 2007, Compton had 197 full-time employees in its Calgary office and 56 full-time employees at field locations.

Competitive Conditions

Competitive conditions affecting the oil and gas industry are described under the heading "Competition" in the "Risk Factors" section of this Annual Information Form.

RISK FACTORS

Volatility of Prices, Markets, and Marketing Production

Oil and gas prices have historically been extremely volatile. The average prices that the Company currently receives for its production are higher than historic averages. Factors which contribute to oil and gas price fluctuations include global demand, domestic and foreign supplies of oil and gas, the price of foreign oil and gas imports, decisions of the Organization of Petroleum Exporting Countries relating to export quotas, domestic and foreign governmental regulations, political conditions in producing regions, global and domestic economic conditions, the price and availability of alternative fuels, including liquefied natural gas, and weather conditions.

The Company's financial condition is substantially dependent on, and highly sensitive to, oil and gas commodity prices. Any material decline in prices could result in a material reduction of Compton's operating results, revenue, reserves, and overall value. Lower commodity prices could change the economics of production from some wells. As a result, the Company could elect not to drill, develop, or produce from certain wells. In addition, Compton is impacted by the differential between prices paid by refiners for light quality oil and the grades of oil produced by the Company.

Under Canadian generally accepted accounting principles, oil and gas assets are reviewed quarterly to determine if the carrying value of the assets exceeds their expected future cash flows. A sustained period of low commodity prices may reduce expected future cash flows and require a write down to the fair value of the Company's oil and gas properties, thereby adversely affecting operating results.

Any future and sustained period of weakness in oil and gas prices would also have an adverse effect on the Compton's capacity to borrow funds. The Company's senior secured credit facilities is based upon the lenders' estimate of the value of the Company's proved reserves, which determines the borrowing amount. A reduction in the quantity or value of reserves may also obligate Compton to make additional payments under the processing agreement with MPP.

Any decline in the Company's ability to market production could have a material adverse effect on production levels or on the sale price received for production. Compton's ability to market the oil and gas from the Company's wells depends on numerous factors beyond the Company's control, including the availability and capacity of gas gathering systems, pipelines and processing facilities, and their proximity to the wells. The Company will be impacted by Canadian federal and provincial, as well as U.S. federal and state, energy policies, taxes, regulation of oil and gas production, processing, and transportation, as well as Canadian federal regulation of oil and gas sold or transported outside of the province of Alberta.

Need to Replace Reserves

Compton's future success depends upon the Company's ability to find, develop, or acquire additional oil and gas reserves that are economically recoverable. Without successful exploration, development, exploitation, or acquisition activities, the Company's reserves will deplete and, as a consequence, either production or the average life of reserves will decline. If future production declines to the extent that cash flow becomes insufficient to fund capital expenditures, and external sources of capital become limited or unavailable, the Company's ability to make the necessary capital expenditures to maintain and expand its oil and gas reserves will be impaired. Compton cannot guarantee that it will be able to find and develop or acquire additional reserves at an acceptable cost.

Management will continue to evaluate prospects on an ongoing basis in a manner consistent with industry standards and past practices. The long term commercial success of the Company depends on its ability to

find, acquire, develop, and commercially produce oil and gas reserves. No assurance can be given that Compton will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, the Company may determine that current markets, terms of acquisition and participation, or pricing conditions make such acquisitions or participations uneconomic.

Compton's strategies to minimize this inherent risk include focusing on selected core areas in Western Canada with high working interests and assuming operatorship of key facilities. The Company utilizes a team of highly qualified professionals with expertise and experience in these areas. Compton assesses strategic acquisitions to complement existing activities while striving for a balance between exploration and lower risk development and exploitation prospects.

Uncertainty of Reserve Estimates

Estimates of oil and gas reserves, and the future net cash flow therefrom, involve a great deal of uncertainty because they depend upon the reliability of available geologic and engineering data, which is inherently imprecise. Geologic and engineering data are used to determine the probability that an oil and gas reservoir exists at a particular location and whether oil and gas are recoverable from the reservoir. The probability of the existence and recoverability of reserves is less than 100% and actual recoveries of proved reserves may be materially different from estimates.

Estimates of oil and gas reserves require numerous assumptions relating to operating conditions and economic factors, including future oil and gas prices, recovery costs, the availability of enhanced recovery techniques, the ability to market production, and governmental and other regulatory factors, such as taxes, royalty rates, and environmental laws. A change in one or more of these factors could result in known quantities of oil and gas previously estimated as proved reserves becoming unrecoverable. Each of these factors also impact recovery costs and production rates, and therefore, will reduce the present value of future net cash flows from estimated reserves.

In addition, estimates of reserves, and future net cash flows expected therefrom, that are prepared by different independent engineers or by the same engineers at different times, may vary substantially.

Exploration, Development, and Production Risks

There are many operating risks and hazards inherent in exploring for, producing, processing, and transporting oil and gas. Drilling operations may encounter unexpected formations or pressures that could cause damage to equipment or personal injury and fires, explosions, blowouts, oil spills, or other accidents may occur. Additionally, Compton could experience interruptions to or the termination of drilling, production, processing, and transportation activities due to bad weather, natural disasters, delays in obtaining governmental approvals or consents, insufficient storage or transportation capacity, or other geological and mechanical conditions. Any of these events resulting in a shutdown or slowdown of operations, will adversely affect the Company's business. While close well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Drilling activities, including completions, are subject to the risk that no commercially productive reservoirs will be encountered and the Company will not recover all or any portion of its investment. The cost of drilling, completing, and operating wells is often uncertain due to drilling in unknown formations, the costs associated with encountering various drilling conditions, such as over pressured zones, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

Insurance

The risks and hazards of Compton's operations could result in damage to, or destruction of, oil and gas wells, production and processing facilities, pipelines or other property, environmental damage, or personal injury for which the Company will be liable. The location of operations near populated areas, including residential areas, commercial business centers, and industrial sites could increase these risks and hazards. The Company cannot fully protect against all of these risks, nor are all of these risks insurable. Compton may become liable for damages arising from these events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. The occurrence of a significant event not fully insured or indemnified against could seriously harm Compton's financial condition and operating results.

Competition

The oil and gas industry is highly competitive. The Company competes for capital, acquisitions of reserves, undeveloped lands, skilled personnel, access to drilling rigs, service rigs and other equipment, access to processing facilities, and pipeline and refining capacity with a substantial number of other organizations, many of which may have greater technical and financial resources than Compton. Some of these organizations not only explore for, develop and produce oil and gas but also carry on refining operations and market crude oil and other products on a worldwide basis. As a result of these complementary activities, some competitors may have greater and more diverse competitive resources to draw on than does Compton.

Availability of Drilling Equipment and Access Restrictions

Compton's drilling operations could be curtailed, delayed, or cancelled as a result of access restrictions or shortages or delays in the delivery of equipment and services. Oil and gas industry operations in the WCSB are affected by road bans imposed from time to time, which can restrict access to well sites and production facility sites. In addition, landowner constraints or poor surface conditions could disrupt access to the Company's properties. Compton's inability to access the Company's properties or to conduct business as planned could result in a shutdown or slowdown of operations.

Exploration and development activities also depend on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Increased demand for that equipment or imposed access restrictions may affect the availability of equipment to the Company and may delay exploration and development activities.

Additional Funding Requirements

Compton's ongoing activities may not generate sufficient cash flow from operations to fund future exploration, development, or acquisition programs. The Company may require additional funding and there can be no assurance that debt or equity financing will be available or sufficient to meet these requirements or that it will be on acceptable terms. Failure to obtain such financing on a timely basis could cause Compton to forfeit interests in certain properties, miss certain acquisition opportunities, and reduce or terminate operations. This may result in the Company not being able to replace its reserves or maintain production, which will have an adverse effect on its financial position.

Reliance on Key Employees

Compton depends to a large extent on the services of key management personnel, including the Company's executive officers and other key employees, the loss of any of whom could have a material adverse effect on operations. The Company does not maintain key man life insurance with respect to any employees. Compton's success will be dependent upon its ability to continue to employ and retain skilled personnel.

Proposed Changes to the Alberta Royalty Regime

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" ("NRF") containing proposed changes to the Alberta royalty regime scheduled to come into effect on January 1, 2009. The proposed changes include an increase in the royalties collected by the Alberta government and a change in the royalty structure for natural gas and conventional oil by adjusting the current sliding rate formulae that are price and volume sensitive. It is anticipated that the changes proposed in the NRF will result in Compton paying marginally increased royalty rates in Alberta.

It is not possible at this time to determine the full impact of the NRF on Compton's financial condition and operations. There is no assurance that the NRF will be implemented in the form, or on the schedule, proposed. If changes are made to the NRF before it is implemented, such changes may create a royalty regime that will impact Compton in a materially different manner, and may be more or less adverse to Compton, than the NRF as currently proposed.

Environmental Risks

The oil and gas industry is subject to extensive environmental laws and regulations pursuant to local, provincial, and federal legislation. Environmental regulation provides for, among other things, restrictions and prohibitions on the generation, handling, storage, transportation, treatment, and disposal of hazardous substances and waste from spills, releases, or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells, facility sites, and other properties associated with the Company's operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. Under environmental legislation, Compton may be liable for personal injury, clean-up costs, remedial measures, and other environmental and property damages, as well as administrative, civil, and criminal penalties.

Furthermore, future changes in environmental laws and regulations, including adoption of stricter standards or more stringent enforcement, could result in curtailment of production or materially increased costs, such as fines, incurred liability, and increased capital expenditures and operating costs, any of which could have a material adverse effect on Compton's financial condition. For example, Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide, and other so-called "greenhouse gases." On June 22, 2007, the *Kyoto Protocol Implementation Act* received royal assent and was implemented to ensure that Canada meets its global climate change obligations under the Kyoto Protocol through a yearly Climate Change Plan prepared by the Minister of Environment which will set out measures by which Canada will meet its obligations. On March 10, 2008 the federal government announced its plan, "Turning the Corner – Taking Action to Fight Climate Change" to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050. As Compton's production facilities and other operations and activities emit greenhouse gases, this plan will subject Compton to these emissions targets and may subject the Company to legislation that will require increasingly strict regulation with respect to the emissions of greenhouse gases.

Other evolving environmental legislation and actions which could result in a material adverse effect on Compton's financial condition are as follows:

- Canada's *Clean Air Act* - the Government of Canada released the first reading of this Act on October 19, 2006; however, the policy framework for the new legislation has not been released and detailed targets, timeframes and compliance options have not yet been set by the federal government. Future federal legislation may require the reduction of emissions or emissions intensity of the Company's operations and facilities;
- Alberta's *Climate Change and Emissions Management Act* (which has been in existence since 2003, but did not come into effect until July 1, 2007) has outlined emission reduction guidelines which require Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year to reduce their emissions intensity by 12%. Companies have three ways in which to meet their reductions: (i) make operating improvements; (ii) purchase Alberta-based emissions offsets; or (iii) acquire fund credits by making contributions to the Climate Change and Emissions Management Fund;
- *Alberta's 2008 Climate Strategy: Responsibility/Leadership/Action* - on January 24, 2008, the Alberta Government announced a new climate change action plan that is intended to cut Alberta's projected greenhouse gas emissions in half by 2050. The plan focuses on carbon capture and storage, consumer incentives for energy conservation and efficiency and greener energy production through increased investment in clean energy technologies and incentives for the use of renewable and alternative energy sources; and
- Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force - on March 8, 2007, the Government of Canada and the Province of Alberta announced the formation of this Task Force to recommend the best ways for Canada to implement technology to capture carbon dioxide and store it deep underground. The final report of this Task Force was released on January 31, 2008 which recommends, among other things: (i) incorporating carbon capture and storage into federal and provincial greenhouse gas legislation; (ii) allocating new funding into projects through a competitive process; and (iii) targeting research to lower the cost of carbon capture technology.

Given the evolving nature of climate change action and regulation, it is not possible to predict the nature of future legislation with respect to climate change or the impact on the Company, its operations and financial condition at this time.

Compliance with such legislation may require significant expenditures and a failure to comply may result in the issuance of "clean up" orders or the imposition of fines and penalties, some of which may be material. It is possible that the costs of complying with environmental regulations in the future will have a material adverse effect on the Company's financial condition or results of operations. Compton may incur liabilities that could be material or require the Company to cease production on properties if environmental damage occurs.

Compton has not established a separate reclamation fund for the purpose of funding estimated future environmental and reclamation obligations. The Company cannot assure that it will be able to satisfy future environmental and reclamation obligations. Any site reclamation or abandonment costs incurred in the ordinary course in a specific period will be funded out of cash flow from operations. Should Compton be unable to fully fund the cost of remedying an environmental claim, the Company might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy.

The Company is not fully insured against certain environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time, as opposed to sudden and catastrophic damages, is not available on economically reasonable terms. Accordingly, Compton's properties may be subject to liability due to hazards that cannot be insured against or that have not been insured against due to prohibitive premium costs or for other reasons.

STATEMENT OF RESERVES DATA

Compton's interests in its major natural gas and crude oil properties which represents 96% of the Company's oil and natural gas reserves, have been evaluated in a report (the "**Major Report**") as of December 31, 2007, prepared by the independent international integrated petroleum engineering and geological firm, Netherland, Sewell & Associates, Inc. ("**Netherland Sewell**"). Compton's interest in the minor natural gas and crude oil properties which represent 4% of the Company's oil and natural gas reserves have been evaluated in a minor report as of December 31, 2007, prepared internally by Compton. The following summary of the Company's reserves is calculated and reported in accordance with National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities". Assumptions and qualifications relating to costs, prices for future production, and other matters are included below. The Major Report is based on data supplied by the Company and on Netherland Sewell's opinions of reasonable practice in the industry.

All evaluations of future net revenue are after the deduction of future income tax expenses (unless otherwise noted in the tables), royalties, development costs, production costs, and well abandonment costs, but before consideration of indirect costs such as administrative, overhead, and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of Compton's reserves. There is no assurance that the forecast price and cost assumptions contained in the Major Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to the following tables. The recovery and reserves estimates on Compton's properties described herein are estimates only. The actual reserves on Compton's properties may be greater or less than those calculated and these variances may be material. Compton has no heavy oil reserves and "crude oil" refers to light and medium crude oil only.

This statement is dated March 24, 2008. The information being provided in this statement has an effective date of December 31, 2007 and a preparation date of February 29, 2008.

The Report on Reserves Data by Compton's independent qualified reserves evaluators in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached hereto as Schedule "A" and "B" respectively.

Forecast Prices and Costs

A summary of the Company's reserves by product type based upon forecast price and cost assumptions, before and after applicable royalties, at the end of the most recent fiscal year, is presented below.

Summary of Oil and Gas Reserves Using Forecast Pricing as of December 31, 2007

Reserves Category ⁽¹⁾	Crude Oil		Natural Gas ⁽²⁾		Ngl's		Sulphur	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mlt)	Net (Mlt)
Proved								
Developed producing	9,015	8,501	502,312	411,193	9,182	6,498	1,968	1,674
Developed non-producing	222	197	54,579	45,348	1,079	749	66	55
Undeveloped	1,695	1,502	187,629	153,912	2,100	1,432	149	124
Total proved	10,933	10,199	744,520	610,454	12,362	8,679	2,183	1,853
Probable	6,495	5,842	624,604	509,753	9,820	6,879	839	711
Total proved plus probable	17,427	16,042	1,369,124	1,120,208	22,182	15,558	3,022	2,563

(1) Numbers may not add due to rounding.

(2) The solution and associated gas represents 2% of the Company's natural gas reserves and is therefore considered immaterial and is not broken out.

The tables set forth below summarize the Company's future net revenue as of December 31, 2007, based on forecast prices and cost assumptions.

Summary of Future Net Revenue as of December 31, 2007 (Forecast Prices)

Reserves Category ⁽¹⁾	Future Net Revenue (\$000s)					
	Before Income Taxes Discounted at (%/year)					
	0%	5%	8%	10%	15%	20%
Proved						
Developed producing	2,871,487	1,768,094	1,452,542	1,304,364	1,052,974	894,081
Developed non-producing	383,001	228,951	182,516	160,474	122,947	99,404
Undeveloped	1,020,126	561,293	415,622	344,872	222,290	144,771
Total proved	4,274,614	2,558,337	2,050,680	1,809,710	1,398,212	1,138,255
Probable	3,800,077	1,894,415	1,355,781	1,109,123	708,309	475,143
Total proved plus probable	8,074,691	4,452,752	3,406,461	2,918,833	2,106,520	1,613,398

(1) Numbers may not add due to rounding.

Reserves Category ⁽¹⁾	Future Net Revenue (\$000s)					
	After Income Taxes Discounted at (%/year)					
	0%	5%	8%	10%	15%	20%
Proved						
Developed producing	2,385,378	1,559,261	1,296,437	1,170,811	956,188	820,703
Developed non-producing	312,596	195,123	157,460	139,416	108,604	89,271
Undeveloped	791,808	441,507	324,431	267,287	168,360	106,196
Total proved	3,489,782	2,195,891	1,778,327	1,577,515	1,233,151	1,016,171
Probable	2,844,624	1,440,193	1,012,163	815,019	497,843	318,226
Total proved plus probable	6,334,406	3,636,084	2,790,490	2,392,534	1,730,995	1,334,397

(1) Numbers may not add due to rounding.

Undiscounted total future net revenue calculated using forecast prices and costs incorporates the elements presented in the table below.

Total Future Net Revenue (Undiscounted) as of December 31, 2007 (Forecast Prices)

Reserves Category	Revenue (\$000s)	Royalties (\$000s)	Operating Costs (\$000s)	Development Costs (\$000s)	Well Abandonment Costs ⁽¹⁾ (\$000s)	Future Net Revenue Before Income Taxes (\$000s)	Income Taxes (\$000s)	Future Net Revenue After Income Taxes (\$000s)
Proved	9,479,950	1,779,099	3,045,606	318,386	62,245	4,274,614	784,832	3,489,782
Proved plus probable	17,189,666	3,285,085	4,572,123	1,164,773	92,994	8,074,691	1,740,285	6,334,406

(1) Includes, at minimum, well abandonment costs (rather than total abandonment and reclamation costs).

The following table summarizes the Company's total future net revenue using forecast price and cost assumptions, before income taxes, by production group.

Total Future Net Revenue by Production Group as of December 31, 2007 (Forecast Prices)

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) (\$000s)	Unit Value ⁽³⁾ Before Income Tax (discounted at 10%/year) (\$/bbl - \$/Mcf)
Proved	Crude oil ⁽¹⁾	299,508	\$29.37
	Natural gas and ngl ⁽²⁾	1,510,203	\$2.47
Proved plus probable	Crude oil ⁽¹⁾	446,473	\$27.83
	Natural gas and ngl ⁽²⁾	2,472,361	\$2.21

(1) Includes solution gas and related ngl.

(2) Excludes solution gas and related ngl.

(3) Unit values are based on net reserves.

Pricing Assumptions

Future net revenue calculated using forecast prices and costs is based upon the price assumptions set out below. Netherland Sewell incorporated price forecasts which were the average of the December 31, 2007 pricing forecasts prepared by four major Canadian consulting firms in estimating Compton's reserves data using forecast pricing and costs.

Summary of Forecast Pricing and Inflation Rate Assumptions as of December 31, 2007

Year	Crude Oil		Natural Gas		NGLS		Sulphur	Inflation Rate ⁽¹⁾	Exchange Rate
	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par 40° API (\$Cdn/bbl)	AECO C Spot (\$Cdn/MMbtu)	Propane (\$Cdn/bbl)	Butane (\$Cdn/bbl)	Pentanes+ (\$Cdn/bbl)	Plant Gate (\$Cdn/lt)	%/Year	\$Cdn/\$US
Forecast									
2008	\$89.15	\$88.48	\$6.74	\$53.64	\$67.25	\$91.04	\$39.00	2.0%	1.00
2009	\$85.58	\$85.52	\$7.48	\$52.35	\$65.02	\$88.03	\$29.17	2.0%	0.99
2010	\$83.25	\$83.88	\$7.69	\$51.53	\$63.83	\$86.41	\$22.67	2.0%	0.98
2011	\$80.99	\$82.03	\$7.80	\$50.60	\$62.46	\$84.54	\$22.84	2.0%	0.98
2012	\$80.18	\$81.16	\$7.84	\$50.17	\$61.81	\$83.66	\$23.12	2.0%	0.98
2013	\$79.85	\$80.79	\$8.04	\$50.12	\$61.53	\$83.30	\$23.40	2.0%	0.98
2014	\$81.03	\$81.99	\$8.26	\$50.89	\$62.45	\$84.55	\$24.15	2.0%	0.98
2015	\$82.24	\$83.25	\$8.46	\$51.72	\$63.39	\$85.84	\$24.92	2.0%	0.98
2016	\$83.47	\$84.49	\$8.64	\$52.53	\$64.31	\$87.11	\$25.69	2.0%	0.98
2017	\$85.16	\$86.21	\$8.84	\$53.65	\$65.62	\$88.90	\$26.50	2.0%	0.98
Thereafter	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	0.98

(1) Inflation rate for operating and capital costs.

The weighted average realized sales price for Compton for the year ended December 31, 2007 was \$6.33/Mcf for natural gas, \$64.17/bbl for crude oil, \$63.61/bbl for ngl's, and \$6.78/lt for sulphur.

Reserves Reconciliation

The following table provides a summary of the changes in the Company's reserves which occurred in the most recent fiscal year, based upon forecast price and cost assumptions.

Reconciliation of Gross Reserves by Product Type Using Forecast Prices and Costs⁽¹⁾

	Crude Oil			Ngls		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)
December 31, 2006	19,999	9,234	29,233	11,189	7,879	19,068
Extensions	164	456	620	479	865	1,344
Improved recovery	104	28	132	133	155	288
Technical revisions	1,318	(3,620)	(2,302)	232	118	349
Discoveries	122	77	199	458	189	647
Acquisitions	612	319	931	774	629	1,403
Dispositions	(9,581)	-	(9,581)	(172)	(14)	(186)
Production	(1,805)	-	(1,805)	(731)	-	(731)
December 31, 2007	10,933	6,495	17,427	12,362	9,820	22,182

(1) Prepared by Management. Numbers may not add due to rounding.

	Natural Gas			Sulphur		
	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mlt)	Gross Probable (Mlt)	Gross Proved Plus Probable (Mlt)
December 31, 2006	686,838	502,260	1,189,098	1,557	714	2,271
Extensions	29,980	89,284	119,264	-	-	-
Improved recovery	12,269	12,696	24,965	-	-	-
Technical revisions	14,235	(38,824)	(24,589)	705	126	830
Discoveries	18,054	10,691	28,745	-	-	-
Acquisitions	49,178	49,923	99,101	-	-	-
Dispositions	(13,124)	(1,426)	(14,550)	-	-	-
Production	(52,910)	-	(52,910)	(79)	-	(79)
December 31, 2007	744,520	624,604	1,369,124	2,183	839	3,022

(1) Prepared by Management. Numbers may not add due to rounding.

	Total Reserves		
	Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved Plus Probable (Mboe)
December 31, 2006	147,218	101,537	248,755
Extensions	5,640	16,202	21,841
Improved recovery	2,282	2,299	4,581
Technical revisions	4,627	(9,848)	(5,221)
Discoveries	3,589	2,048	5,637
Acquisitions	9,583	9,269	18,851
Dispositions	(11,940)	(252)	(12,192)
Production	(11,434)	-	(11,434)
December 31, 2007	149,564	121,255	270,819

(1) Prepared by Management. Numbers may not add due to rounding.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following discussion generally describes the basis on which Compton attributes proved and probable undeveloped reserves and its plans for developing those undeveloped reserves.

Proved Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year, or wells further away from the Company's gathering systems. In addition, such reserves may relate to planned infill drilling locations. The majority of these reserves are planned to be in production within a two year timeframe.

The following table summarizes the Company's proved undeveloped reserves over the past three years using forecast price and cost assumptions by production type.

Year	Total Proved Undeveloped			
	Crude Oil (Mbbbl)	Natural Gas (MMcf)	Ngls (Mbbbl)	Sulphur (Mlt)
2007	1,695	187,629	2,100	149
2006	3,220	174,999	2,016	115
2005	5,019	84,333	1,731	118

Probable Undeveloped Reserves

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive infill drilling locations and lands contiguous to production. The majority of these reserves are planned to be in production by the end of 2010.

The following table summarizes the Company's probable undeveloped reserves over the past three years using forecast price and cost assumptions by production type.

Year	Total Probable Undeveloped			
	Crude Oil (Mbbbl)	Natural Gas (MMcf)	Ngls (Mbbbl)	Sulphur (Mlt)
2007	3,302	482,866	4,685	528
2006	5,533	420,522	6,446	526
2005	5,779	355,237	5,646	772

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and natural gas prices and costs change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information.

The reserve estimates contained herein are based on current production forecasts, prices, and economic conditions. Compton's reserves are evaluated by Netherland Sewell.

Future Development Costs

The following table provides a summary of the development costs deducted in the estimation of future net revenue attributable to each of the reserves categories set out below:

Undiscounted Development Costs Deducted in Estimating Future Net Revenues⁽¹⁾

Year	Proved	Proved Plus Probable
	Forecast Prices and Costs/Year (\$000s)	Forecast Prices and Costs/Year (\$000s)
2008	\$191,081	\$297,416
2009	104,598	338,215
2010	21,164	254,466
2011	6,158	162,108
2012	3,624	61,308
Remaining	54,006	144,254
Total	\$380,631	\$1,257,767

(1) Includes abandonment costs. Numbers may not add due to rounding.

Compton estimates that its internally generated cash flow will be sufficient to fund the future development costs disclosed above. Compton typically has available three sources of funding to finance its capital expenditure program: (i) internally generated cash flow from operations; (ii) debt financing when appropriate; and (iii) new equity issues, if available on favourable terms. Compton does not expect that the costs of funding its capital expenditures will have a material effect on the economics of the programs.

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

The following table summarizes the location of the Company's important interests as at December 31, 2007 in crude oil and natural gas wells which are producing or which the Company considers to be capable of production.

Area	Producing Crude Oil Wells		Non-producing Crude Oil Wells ⁽²⁾		Producing Natural Gas Wells		Non-producing Natural Gas Wells ⁽²⁾		Total Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta										
South	144	57	41	8	1,619	1,112	312	232	2,116	1,409
Central	150	91	40	10	262	141	108	38	560	280
Peace River Arch	245	95	49	21	96	39	40	17	430	172
BC	1	-	2	-	44	3	6	1	53	4
Total wells	540	243	132	39	2,021	1,295	466	288	3,159	1,865

(1) Numbers may not add due to rounding.

(2) A portion of the non-producing wells are wells considered capable of production but which, for a variety of reasons including but not limited to a lack of markets and lack of development, cannot be placed on production at the present time.

Properties with No Attributed Reserves

The following table sets forth the Company's undeveloped land holdings to which no proved reserves have been attributed as at December 31, 2007.

Area	Gross Acres	Net Acres
British Columbia	25,344	4,082
Alberta	1,092,588	886,382
Saskatchewan	1,918	1,918
Manitoba	1,280	1,080
Total	1,121,130	893,462

Approximately 32,000 net acres of undeveloped land could expire by December 31, 2008. However, the Company's 2008 exploration and development activities will defer the expiry of a portion of these lands.

Forward Contracts

In 2007, Compton's realized average field price was \$43.82/boe, comprised of \$6.33/Mcf for natural gas and \$62.28/bbl for liquids. In 2006, Compton's realized average field price was \$44.65/boe, comprised of \$6.32/Mcf for natural gas and \$59.09/bbl for liquids.

Compton's natural gas production is sold under a combination of longer term contracts with aggregators and short term daily or monthly indexed contracts. Approximately 10% of the Company's natural gas production in 2007 was committed to aggregators. The average aggregator price realized was \$0.75/Mcf less than the non-aggregator prices realized during the year.

Compton's crude oil sales are priced at Edmonton postings and are typically sold on 30 day evergreen arrangements. Natural gas liquids are bid out on an annual basis to establish the most competitive pricing. The Company sells crude oil and ngl's primarily to refineries and marketers of crude oil and ngl's.

From time to time, Compton may enter into hedging arrangements to mitigate commodity price risk and take advantage of opportunistic pricing. In accordance with Compton's policy, hedging programs will not exceed 60% of non-contracted net production.

Additional Information Concerning Abandonment and Reclamation Costs

Compton is required to remove production equipment, batteries, pipelines, and natural gas plants and to restore land at the end of oil and natural gas operations. The Company estimates these costs in accordance with existing laws, contracts, and other policies. These obligations are initially measured at fair value, which is the discounted future value of the liability. This fair value is also capitalized as part of the cost of the related assets and amortized over the useful life of the assets.

An independent environmental consulting firm was hired to assist Management in the estimation of the Company's asset retirement obligations ("ARO"). ARO cost calculations were derived from a combination of actual third party cost quotes, EUB cost models, and typical industry experience and practices. The deemed ARO liability for Compton's 1,900 net well sites and facilities is the sum of the calculated abandonment and reclamation liabilities adjusted for designated status as an active, inactive, abandoned, or problem site. Information regarding environmental remediation costs and other liability issues for site specific concerns were derived from a review of historical audit and assessment reports of

sites and facilities. An inflation rate of 2% and a credit adjusted risk free rate of 10.8% was used in the fair value calculation.

Total asset retirement costs, net of estimated salvage values, is estimated to be \$116 million or \$12 million when discounted at 10%. The undiscounted ARO associated with pipelines and facilities is estimated to be \$49 million and is not deducted in estimating total future net revenue, as calculated in the Company's reserve report. The Company expects to pay \$7 million dollars in ARO costs between 2008 and 2011.

Tax Horizon

Based upon planned capital expenditure programs and current commodity price assumptions, it is anticipated the Company will not be cash taxable until at least 2010.

Capital Expenditures

In 2007, Compton incurred approximately \$43 million of exploration costs and \$252 million of development costs. Additionally, approximately \$109 million was received on proved property net dispositions and \$28 million was spent on unproved property acquisitions.

Exploration and Development Activities

The following table sets forth the number of crude oil and natural gas wells drilled by the Company, or which the Company participated in drilling, that are capable of production, as well as the number of dry and abandoned wells, all expressed in terms of gross and net wells during the years ended December 31, 2007 and 2006.

	Year Ended December 31, 2007				Year Ended December 31, 2006			
	Development		Exploratory		Development		Exploratory	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Natural gas	257	219	19	15	222	180	29	24
Crude oil	24	13	1	1	50	34	6	5
Dry and abandoned	4	4	6	5	17	14	3	3
Total	285	236	26	21	289	228	38	32
Success Ratio	97%				94%			

In 2008, the Company expects to continue to focus its resources in Alberta, Canada. Compton's overall objective for 2008 is the recognition of its unbooked resource potential. The Company has developed a \$410 million capital expenditure plan for 2008, encompassing up to 350 gross wells.

Production History

The Company's average daily production volume of natural gas and liquids, before deduction of royalties, for each of the periods indicated, is set forth below.

Gross Natural Gas and Liquids Production

Product Type	Fiscal 2007 Three Months Ended				Year Ended
	March 31, 2007	June 30, 2007	September 30, 2007	December 31, 2007	December 31, 2007
Natural gas (MMcf/d)	148	130	135	167	145
Natural gas (MMcf)	13,277	11,859	12,413	15,361	52,910
Natural gas liquids (boe/d) ⁽¹⁾	2,705	1,714	2,231	2,239	2,221
Natural gas liquids (Mboe) ⁽¹⁾	243	156	205	206	810
Crude oil (bbl/d)	6,024	5,485	5,723	2,579	4,945
Crude oil (Mbbls)	542	499	526	237	1,805
Total liquids (boe/d)	8,729	7,199	7,954	4,818	7,166
Total liquids (Mboe)	785	655	731	443	2,615
Total (boe/d)	33,316	28,918	30,440	32,646	31,326
Total (Mboe)	2,998	2,632	2,800	3,003	11,434

(1) Includes sulphur.

Product Type	Fiscal 2006 Three Months Ended				Year Ended
	March 31, 2006	June 30, 2006	September 30, 2006	December 31, 2006	December 31, 2006
Natural gas (MMcf/d)	142	137	142	148	142
Natural gas (MMcf)	12,750	12,462	13,024	13,604	51,840
Natural gas liquids (boe/d) ⁽¹⁾	2,843	2,692	2,656	2,642	2,707
Natural gas liquids (Mboe) ⁽¹⁾	256	245	244	243	988
Crude oil (bbl/d)	7,575	7,129	6,593	5,958	6,809
Crude oil (Mbbls)	682	649	607	548	2,486
Total liquids (boe/d)	10,418	9,821	9,249	8,600	9,516
Total liquids (Mboe)	938	894	851	791	3,474
Total (boe/d)	34,029	32,645	32,843	33,245	33,187
Total (Mboe)	3,063	2,971	3,022	3,058	12,114

(1) Includes sulphur.

2008 Production Estimates

Production volumes in 2008, as estimated in the Company's reserve forecast before deduction of royalties, are set forth below.

Reserves Category ⁽¹⁾	Crude Oil(bbl/d)	Natural Gas (MMcf/d)	Ngls (bbl/d)	Sulphur (lt/d)	Total (boe/d)
Proved					
Developed producing	2,648	129	2,218	207	26,553
Developed non-producing	67	12	227	4	2,292
Undeveloped	145	19	254	-	3,592
Total proved	2,860	160	2,699	211	32,436
Probable	538	24	487	3	5,080
Total proved plus probable	3,397	184	3,186	214	37,516

(1) Numbers may not add due to rounding. Based on estimates only. Variances may occur due to circumstances beyond Compton's control.

Compton's property in Niton is estimated to have production volumes in 2008 of 8,439 boe/d which represents 22.5% of the total 2008 production estimate for total proved plus probable reserves.

The Company's per unit results on a quarterly basis for the periods indicated is set forth below.

	Fiscal 2007 Three Months Ended				Year Ended
	March 31, 2007	June 30, 2007	September 30, 2007	December 31, 2007	December 31, 2007
Natural gas (\$/Mcf)					
Price	\$7.24	\$6.92	\$5.23	\$6.00	\$6.33
Royalties	(1.52)	(1.35)	(1.26)	(1.32)	(1.36)
Operating costs ⁽¹⁾	(1.30)	(1.34)	(1.22)	(1.44)	(1.33)
Transportation costs	(0.11)	(0.11)	(0.11)	(0.11)	(0.11)
Netback	\$4.31	\$4.12	\$2.64	\$3.13	\$3.53
Natural gas liquids (\$/bbl)⁽³⁾					
Price	\$49.49	\$52.23	\$51.21	\$79.40	\$58.05
Royalties	(12.61)	(12.10)	(12.32)	(16.34)	(13.39)
Operating costs ⁽¹⁾	(7.79)	(8.01)	(7.32)	(8.61)	(7.97)
Transportation costs	(2.57)	(2.67)	(2.54)	(2.63)	(2.60)
Netback	\$26.52	\$29.45	\$29.03	\$51.82	\$34.09
Crude oil (\$/bbl)					
Price	\$58.13	\$63.08	\$66.09	\$76.04	\$64.17
Royalties	(9.91)	(10.76)	(11.27)	(12.80)	(10.92)
Operating costs ⁽¹⁾	(12.74)	(12.79)	(14.78)	(15.70)	(13.72)
Transportation costs	(2.57)	(2.67)	(2.54)	(2.63)	(2.60)
Netback	\$32.91	\$36.86	\$37.50	\$44.91	\$36.93
Total liquids (\$/bbl)					
Price	\$55.45	\$60.49	\$61.91	\$77.60	\$62.28
Royalties	(10.75)	(11.08)	(11.56)	(14.44)	(11.68)
Operating costs ⁽¹⁾	(11.21)	(11.65)	(12.69)	(12.41)	(11.94)
Transportation costs	(2.57)	(2.67)	(2.54)	(2.63)	(2.60)
Netback	\$30.92	\$35.09	\$35.12	\$48.12	\$36.06
Total (\$/boe)					
Price ⁽²⁾	\$46.98	\$47.94	\$38.56	\$41.94	\$43.82
Royalties	(9.55)	(8.86)	(8.61)	(8.86)	(8.98)
Operating costs ⁽¹⁾	(8.68)	(8.92)	(8.72)	(9.17)	(8.88)
Transportation costs	(1.16)	(1.16)	(1.15)	(.95)	(1.10)
Netback	\$27.59	\$29.00	\$20.08	\$22.96	\$24.86

(1) A portion of our natural gas production is associated with our crude oil production, additionally the production of natural gas liquids is associated with our natural gas production. As a result, per unit operating costs for each product line reflect the allocation of certain common costs in this determination.

(2) Includes third party processing fees, but not included in product pricing.

(3) Includes sulphur.

	Fiscal 2006 Three Months Ended				Year Ended
	March 31, 2006	June 30, 2006	September 30, 2006	December 31, 2006	December 31, 2006
Natural gas (\$/Mcf)					
Price	\$7.58	\$5.86	\$5.38	\$6.48	\$6.32
Royalties	(1.79)	(1.31)	(1.15)	(1.47)	(1.43)
Operating costs ⁽¹⁾	(1.03)	(1.11)	(1.35)	(1.41)	(1.23)
Transportation costs	(0.15)	(0.15)	(0.15)	(0.15)	(0.15)
Netback	\$4.61	\$3.29	\$2.73	\$3.45	\$3.51
Natural gas liquids (\$/bbl)⁽³⁾					
Price	\$43.76	\$54.38	\$53.32	\$42.94	\$48.56
Royalties	(13.52)	(15.29)	(14.87)	(12.36)	(14.01)
Operating costs ⁽¹⁾	(6.19)	(6.66)	(8.13)	(8.49)	(7.37)
Transportation costs	(1.24)	(1.41)	(1.41)	(1.48)	(1.38)
Netback	\$22.81	\$31.02	\$28.91	\$20.61	\$25.80
Crude oil (\$/bbl)					
Price	\$57.84	\$71.89	\$69.11	\$53.39	\$63.28
Royalties	(12.09)	(17.60)	(16.33)	(11.37)	(14.40)
Operating costs ⁽¹⁾	(10.50)	(11.36)	(14.17)	(15.31)	(12.77)
Transportation costs	(1.24)	(1.41)	(1.41)	(1.48)	(1.38)
Netback	\$34.01	\$41.52	\$37.20	\$25.23	\$34.73
Total liquids (\$/bbl)					
Price	\$54.00	\$67.09	\$64.58	\$50.18	\$59.09
Royalties	(12.48)	(16.97)	(15.91)	(11.68)	(14.29)
Operating costs ⁽¹⁾	(9.32)	(10.07)	(12.43)	(13.21)	(11.23)
Transportation costs	(1.24)	(1.41)	(1.41)	(1.48)	(1.38)
Netback	\$30.96	\$38.64	\$34.83	\$23.81	\$32.19
Total (\$/boe)					
Price ⁽²⁾	\$48.58	\$45.37	\$42.03	\$42.60	\$44.65
Royalties	(11.29)	(10.59)	(9.42)	(9.54)	(10.21)
Operating costs ⁽¹⁾	(7.15)	(7.69)	(9.34)	(9.71)	(8.47)
Transportation costs	(1.00)	(1.05)	(1.04)	(1.05)	(1.04)
Netback	\$29.14	\$26.04	\$22.23	\$22.30	\$24.93

(1) A portion of our natural gas production is associated with our crude oil production, additionally the production of natural gas liquids is associated with our natural gas production. As a result, per unit operating costs for each product line reflect the allocation of certain common costs in this determination.

(2) Includes third party processing fees, but not included in product pricing.

(3) Includes sulphur.

(4) Certain amounts have been reclassified to conform with current period presentation.

The following table indicates average daily gross production from important areas in respect of Compton's assets for the year ended December 31, 2007:

	Crude Oil (Bbls/d)	Natural Gas (Mcf/d)	Ngls (Bbls/d)	Total (Boe/d)
Southern Alberta	340	79,109	1,050	14,575
Central Alberta	1,086	50,855	919	10,480
Peace River Arch	3,418	14,435	182	6,007
Other	101	561	70	264
	<u>4,945</u>	<u>144,960</u>	<u>2,221</u>	<u>31,326</u>

DIVIDENDS

The Company has neither declared nor paid any dividends on its common shares. The Company intends to retain its earnings to finance growth and expand its operations and does not anticipate paying any dividends on its common shares in the foreseeable future.

CAPITAL STRUCTURE

Compton is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares, of which 129,317,421 common shares are issued and outstanding as fully paid and non-assessable share as at March 25, 2008. No preferred shares are issued and outstanding as at March 25, 2008. The following is a description of Company's common and preferred shares.

Common Shares

Common shares have attached to them the following rights, privileges, restrictions, and conditions: (i) except for meetings at which only holders of another specified class or series of shares of the Company are entitled to vote separately as a class or series, each holder of a common share is entitled to receive notice of, to attend, and to vote at all meetings of the shareholders of the Company; (ii) subject to the rights, privileges, restrictions, and conditions attached to any preferred shares, the holders of common shares are entitled to receive dividends if, and when, declared by the directors of the Company; and (iii) subject to the rights, privileges, restrictions, and conditions attached to any other class of shares of the Company, the holders of common shares are entitled to share equally in the remaining property of the Company upon liquidation, dissolution, or winding-up of the Company.

Preferred Shares

The preferred shares may be issued in one or more series, and the directors are authorized to fix the number of shares in each series and to determine the designation, rights, privileges, restrictions, and conditions attached to the shares of each series. Holders of preferred shares do not hold voting rights. The preferred shares are entitled to a priority over the common shares with respect to the payment of dividends and the distribution of assets upon the liquidation, dissolution, or winding-up of Compton.

Shareholder Rights Plan

Compton has a shareholder rights plan (the “**Rights Plan**”) under the terms of a shareholder rights plan agreement dated as of April 22, 2003 between the Company and Computershare Trust Company of Canada, as rights agent. The Rights Plan is designed to encourage the fair treatment of shareholders in connection with a take-over bid for Compton. Rights issued under the Rights Plan become exercisable when a person, and any related parties, acquires or announces its intention to acquire 20% or more of the outstanding Common Shares without complying with certain provisions set out in the Rights Plan or without approval of the Board of directors of Compton. Should such an acquisition or announcement occur, each rights holder, other than the acquiring person and related parties, will have the right to purchase Common Shares at a 50% discount to the market price at that time. The Rights Plan was ratified by and extended to June 3, 2009 by shareholders at the annual and special meeting of Compton shareholders held on May 10, 2006.

MARKET FOR SECURITIES

The outstanding common shares of the Company are listed on the Toronto Stock Exchange (“**TSX**”) under the symbol CMT and on the New York Stock Exchange until the symbol CMZ. The following table sets out the high and low closing prices and average trading volume of common shares as reported by the TSX, for the periods indicated.

Period	TSX High Close	TSX Low Close	TSX Average Daily Trading Volume
2007			
January	\$11.42	\$9.57	492,536
February	\$11.40	\$10.54	322,984
March	\$11.81	\$10.22	493,522
April	\$12.27	\$11.38	346,252
May	\$13.19	\$11.92	458,374
June	\$12.65	\$10.58	485,356
July	\$11.50	\$10.45	799,383
August	\$10.96	\$9.40	596,761
September	\$10.01	\$9.17	359,196
October	\$9.40	\$8.20	487,587
November	\$8.30	\$7.40	519,224
December	\$9.26	\$7.87	420,086
2008			
January	\$9.79	\$8.79	409,255
February	\$11.80	\$9.75	536,633
March 1-25	\$12.05	\$11.03	427,023

CONFLICTS OF INTEREST

The directors and officers of Compton are engaged in and will continue to engage in other activities in the oil and natural gas industry and as a result of these and other activities, the directors and officers of Compton may become subject to conflicts of interest. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA. As at the date hereof, Compton is not aware of any existing or potential material conflicts of interest between Compton and a director or officer of the Company.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the current executive officers or directors of Compton, and no person or company that is the direct or indirect beneficial owner of, or who exercised control or direction over more than 10% of the common shares of Compton, nor any associate or affiliate of the foregoing has or has had, at any time, any material interest, directly or indirectly, in any transaction or proposed transaction that has materially affected or would materially affect Compton.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

None of those persons who are directors or officers of Compton is or has been within the past 10 years, a director, chief executive officer or chief financial officer of any company, including Compton, that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied company access to any exemption under securities legislation, for a period of more than 30 consecutive days, or after such persons ceased to be a director, chief executive officer or chief financial officer of the company was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, for a period of more than 30 consecutive days, which resulted from an event that occurred while acting in such capacity.

In addition, none of those persons who are directors or executive officers of Compton or a shareholder holding a sufficient number of securities of Compton to affect materially the control of the Company, is, or has been within the past 10 years, a director or executive officer of any company, including Compton, that while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold assets.

None of the persons who are directors or officers of Compton have been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, Compton has not entered into any material contracts within the last financial year, or before the last financial year which are still in effect, other than as follows: an Indenture dated as of November 22, 2005, among Compton Petroleum Finance Corporation, Compton, as parent guarantor, Hornet Energy Ltd., Compton Petroleum (partnership) and Compton Petroleum Holdings Corporation, as the initial subsidiary guarantors, and The Bank of Nova Scotia Trust Company of New York, as trustee, whereby, on November 22, 2005, Compton Petroleum Finance Corporation issued and sold U.S.\$300 million aggregate principal amount of senior term notes, which are unsecured and bear interest semi-annually, in arrears on December 1 and June 1 of each year, at a rate of 7½% per year, with principal repayable on December 1, 2013. On April 4, 2006, Compton Petroleum Finance Corporation issued an additional U.S.\$150 million aggregate principal amount of senior term notes under this Indenture on the same terms and conditions as the senior terms notes issued on November 22, 2005. The senior notes are guaranteed by Compton and the initial subsidiary guarantors.

Compton has a \$500 million (as at December 31, 2007) authorized senior secured credit facility with a syndicate of banks. The credit facility is available for general corporate purposes. The facility reaches term on July 2, 2008 and matures 366 days later on July 3, 2009 at which time must be repaid in full. Compton currently intends to request that the term and maturity of the credit facilities be extended, subject to the bank lenders' consent to such requests.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of the Company, there are no legal proceedings material to the Company to which the Company is or was a party to or of which any of its properties is or was the subject of, during the financial year ended December 31, 2007 nor are there any such proceedings known to the Company to be contemplated.

During the year ended December 31, 2007, there were no: (i) penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority; (ii) penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision, or (iii) settlement agreements the Company entered into before a court relating to securities legislation or with a securities regulatory authority.

INTERESTS OF EXPERTS

As at the date hereof, the partners and associates of Grant Thornton, LLP, the auditors of Compton, as a group, did not beneficially own any of Compton's outstanding common shares. As at the date hereof, principals of Netherland Sewell personally disclosed in certificates of qualification that they neither held, nor expected to receive, any of the Company's outstanding common shares.

RATINGS

Standard & Poor's Rating Services ("S&P") and Moody's Corporation ("Moody's") have rated Compton Petroleum Finance Corporation's U.S. \$450 million 7% Senior Notes as B and B2 respectively, as at December 31, 2007. A security rating is not a recommendation to buy, sell, or hold securities and may be subject to revisions or withdrawal at any time by the rating agency.

An S&P credit rating considers likelihood of payment, nature of and provisions of the obligation, protection afforded by, and relative position of, the obligation in the event of bankruptcy, reorganization, or other arrangement under the laws of bankruptcy and other laws affecting creditors' rights. S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, representing the range from highest to lowest quality of such securities rated. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. According to the S&P rating system, debt securities rated B are vulnerable to nonpayment, but the obligor currently has the capacity to meet its financial commitment on the obligation. Adverse business, financial, or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitment on the obligation.

Moody's credit ratings on long-term structured finance obligations primarily address the expected credit loss an investor might incur on or before the legal final maturity of such obligations, incorporating the probability of default and the severity of the loss. Moody's credit ratings are on a long-term debt rating scale that ranges from Aaa to C, representing the range from least credit risk to greatest credit risk of such securities rated. Moody's applies numerical modifiers 1, 2 and 3 in each generic rating classification from Aa through Caa in its long term debt rating system. The modifier 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking, and the modifier 3 indicates that the issue ranks in the lower end of that generic rating category. According to the Moody's rating system, debt securities rated B2 are considered speculative and are subject to high credit risk.

DIRECTORS AND OFFICERS

Directors

Information is given below with respect to each of the current directors of the Company. All directors of Compton stand for election at each annual meeting of the Company. The next Annual Meeting of Shareholders is scheduled for May 12, 2008 at 3:30 pm. (Calgary time) in the Historical Ballroom on the Fourth Floor of the Calgary Chamber of Commerce, 517 Centre Street South, Calgary, Alberta, Canada.

The Board of directors has established an Audit, Finance and Risk Committee; an Engineering, Operations and Reserves Committee; a Human Resources, Compensation, Environmental, Health and Safety Committee; and a Corporate Governance Committee. All independent directors, other than Peter Seldin, sit on each of the Board Committees. Mr. Sapieha does not sit on the Board Committees since he is a non-independent director due to his position as President & Chief Executive Officer of the Company.

The name, city of residence, and principal occupation during the last five years of each of the directors of the Company are set forth in the following table.

Name and Municipality of Residence	Principal Occupation	Director Since
Mel F. Belich, Q.C. Calgary, AB, Canada	Chairman, Compton Petroleum Corporation. Mr. Belich has been Chairman and President of each of Enbridge International Inc. and Enbridge Technology Inc., and a director of numerous affiliates of Enbridge Inc., a pipeline company, including those in Europe and Latin America. Mr. Belich is the Chairman of the Board of directors of Compton, the Chairman of the Corporate Governance Committee and the Chairman of the Special Committee of Independent Members of the Board.	1993
Ernie G. Sapieha, C.A. Calgary, AB, Canada	President & Chief Executive Officer of the Company.	1993
J. Stephens Allan, F.C.A., ICD.D Calgary, AB, Canada	Consultant to RSM Richter LLP, one of the largest independent accounting, business advisory, and consulting firms in Canada. Mr. Allan has 38 years of experience as a Chartered Accountant, which includes extensive experience in corporate restructuring and complex corporate litigation matters. He was awarded an FCA in 1992.	2007
Irvine J. Koop, P. Eng. Calgary, AB, Canada	Independent businessman and prior thereto was the Chairman and Chief Executive Officer of IKO Resources Inc., a petroleum consulting firm. Mr. Koop was the President and CEO, Pipelines and Midstream of Westcoast Energy Inc., an energy products and services company (acquired by Duke Energy Company), and was the former president and CEO of Numac Energy, an oil and gas company (acquired by Anderson Exploration). Mr. Koop is the Chairman of the Human Resources, Compensation, Environmental, Health and Safety Committee.	1996
John W. Preston Calgary, AB, Canada	Independent Businessman and prior thereto, an Account Executive with Sun Microsystems of Canada Inc., a computer company.	1993
Peter K. Seldin New York, New York, United States	Founder and Managing Member of Centennial Energy Partners, L.L.C., general partner of four energy-sector investment partnerships that invest in oil and gas producers and oilfield service companies worldwide. Mr. Seldin is also a director of Tesco Corporation, an oilfield equipment and services company.	2008
Jeffrey T. Smith, P. Geol. Calgary, AB, Canada	Independent Businessman and prior thereto, Chief Operating Officer of Northstar Energy Corporation, an oil and gas company (acquired by Devon Energy). Mr. Smith is Chairman of the Engineering, Reserves and Operations Committee.	1999
John A. Thomson, C.A. Calgary, AB, Canada	Independent Businessman. Mr. Thomson served as Vice President Corporate Development from 2000 and as a director from 1999, to 2001, of Avid Oil & Gas Ltd., an oil and gas company and prior thereto, he was Senior Vice President and Chief Financial Officer of Renaissance Energy Ltd., an oil and gas company (acquired by Husky Energy Inc.). Mr. Thomson is the Chairman of the Audit, Finance and Risk Committee.	2003

Further information about the directors and the committees of the Board of directors is set forth under the heading "Election of Directors" in the Company's Management Proxy Circular dated March 10, 2008

relating to the Annual Meeting of Shareholders to be held on May 12, 2008, which sections are incorporated by reference into this Annual Information Form.

Officers

The name, city of residence, and principal occupation during the last five years of each of the officers of the Company are set forth in the following table.

Name and Municipality of Residence	Principal Occupation
Ernie G. Sapieha, C.A. Calgary, Alberta	President & Chief Executive Officer of the Company.
Norman G. Knecht, C.A. Calgary, Alberta	Vice President Finance & Chief Financial Officer of the Company.
Tim G. Millar, LL.B. Calgary, Alberta	Vice President, General Counsel & Corporate Secretary of the Company.
Murray J. Stodalka, P. Eng. Calgary, Alberta	Vice President Operations & Engineering of the Company.
Marc R. Junghans, P. Geol. Calgary, Alberta	Vice President Exploration of the Company.

As at March 25, 2008, the directors and officers of Compton as a group beneficially owned or controlled, directly or indirectly, 13,789,135 common shares of Compton, representing approximately 10.7% of the issued and outstanding common shares of the Company. None of the directors or officers held a sufficient number of common shares to materially affect the control of Compton.

AUDIT, FINANCE AND RISK COMMITTEE INFORMATION

The Charter of the Audit, Finance and Risk Committee is set forth in Schedule C.

Composition of the Audit, Finance and Risk Committee

Chairman: John A. Thomson

Members: J. Stephens Allan, Mel F. Belich, Irvine J. Koop, John W. Preston, Jeffrey T. Smith

Based upon applicable Canadian and United States securities laws and the New York Stock Exchange corporate governance rules, Compton has adopted “Standards of Independence,” which may be viewed in full on the Company’s website. The Board affirmatively determines on an annual basis the independence of its members. Messrs. Allan, Belich, Koop, Preston, Smith, and Thomson have been determined to be independent directors.

Mr. Thomson is considered to be a “financial expert,” as defined in National Instrument 52-110, “Audit Committees,” (“NI 52-110”) issued by the CSA, due to his experience in the oil and natural gas industry as a Chartered Accountant, as Chief Financial Officer of a major public oil and natural gas company, and as a board member and Officer for other public reporting oil and natural gas companies. All other Committee members are “financially literate,” as defined in NI 52-110, due to their experience in various management positions or qualification as a Chartered Accountant.

External Auditor Fees

The aggregate amounts paid or accrued by the Company with respect to fees payable to Grant Thornton LLP for audit and audit-related engagements (including separate audits of subsidiary entities, financings, and regulatory reporting requirements), tax and other services in the fiscal years ended December 31, 2007 and 2006 were as follows:

Type of Service	Fiscal 2007	Fiscal 2006
Financial statement audit	\$517,000	\$578,610
Internal controls audit	454,000	690,675
Audit related	43,000	69,220
Tax	-	8,795
Other non-audit	37,699	34,740
Total	\$1,051,699	\$1,382,040

Fees in respect of the fiscal 2007 Internal Controls Audit related to the review of Compton's United States Sarbanes-Oxley Act of 2002, and similar Canadian regulatory, compliance. The audit related fees incurred in fiscal 2007 related to Compton Petroleum Finance Corporation's oil and gas property dispositions. The fees for other non-audit services in fiscal 2007 were incurred to translate the Company's quarterly and annual reports into French.

Fees in respect of the fiscal 2006 Internal Controls Audit related to the review of Compton's United States Sarbanes-Oxley Act of 2002 compliance. The audit related fees incurred in fiscal 2006 related to the Company's U.S.\$150 million Senior Notes offering in March 2006. Tax fees incurred in fiscal 2006 related to the review of tax forms. Fees for other non-audit services in fiscal 2006 related primarily to services incurred to translate the Company's quarterly and annual reports into French.

The Audit, Finance and Risk Committee of the Company considered these fees and determined that they were reasonable and do not impact the independence of the Company's auditors. Further, such Committee determined that in order to ensure the continued independence of the auditors, only limited non-audit related services would be provided to the Company by Grant Thornton LLP and in such case, only with the prior approval of the Audit, Finance and Risk Committee. The Committee has pre-approved Management to retain Grant Thornton LLP to provide miscellaneous, minor, non-audit services in circumstances where it is not feasible or practical to convene a meeting of the Audit, Finance and Risk Committee, subject to an aggregate limit of \$25,000 per quarter.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Company's shares is Computershare Trust Company of Canada at its office in Calgary, Alberta.

ADDITIONAL INFORMATION

Additional information including directors' and officers' remuneration, principal holders of the Company's common shares, options to acquire common shares and interests of insiders in material transactions (if applicable) is contained in the Management Proxy Circular issued by Management dated March 10, 2008, relating to the Annual and Special Meeting of Shareholders to be held on May 12, 2008. Additional financial information is also provided in the consolidated financial statements and MD&A of the Company for the year ended December 31, 2007, included in the Company's 2007 Annual Report. Copies of these and other documents relating to Compton have been filed with the CSA's System for Electronic Document Analysis and Retrieval ("**SEDAR**") at www.sedar.com.

Additional copies of this Annual Information Form are available to the public and may be obtained by contacting:

Compton Petroleum Corporation
Suite 3300, 425 - 1st Street S.W.
Fifth Avenue Place, East Tower
Calgary, Alberta, Canada
T2P 3L8
Attention: Mr. T.G. Millar
Vice President, General Counsel & Corporate Secretary
Telephone: (403) 237-9400
Fax: (403) 237-9410

SCHEDULE A

FORM 51-101F2
REPORT ON RESERVES DATA BY INDEPENDENT
QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Compton Petroleum Corporation (the "Company"):

1. We have evaluated the Company's major properties reserves data as at December 31, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2007, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluated Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before Canadian federal income taxes, 10% discount rate) (MC\$)			
			Audited	Evaluated	Reviewed	Total
Netherlands, Sewell & Associates, Inc.	February 29, 2008	Canada	nil	2,748,246	nil	2,748,246

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we did not evaluate.
6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after its respective preparation date.
7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

NETHERLAND, SEWELL & ASSOCIATES, INC.
Dallas, Texas, USA
March 24, 2008

/s/ C.H. (Scott) Rees III, P.E.

By:

C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

RCB:MBB

Please be advised that the digital document you are viewing is provided by Netherland, Sewell & Associates Inc. (NSAI) as a convenience to our clients. The digital document is intended to be substantively the same as the original signed document maintained by NSAI. The digital document is subject to the parameters, limitations, and conditions stated in the original document. In the event of any differences between the digital document and the original document, the original document shall control and supersede the digital document.

SCHEDULE B

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES ON OIL AND GAS DISCLOSURE

Management of Compton Petroleum Corporation (the “**Company**”) are responsible for the preparation and disclosure of information with respect to the Company’s oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated (in respect of the Company’s major properties) the Company’s reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Engineering, Reserves and Operations Committee of the Board of directors of the Company has:

- (a) reviewed the Company’s procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with Management and the independent qualified reserves evaluator.

The Engineering, Reserves and Operations Committee of the Board of directors has reviewed the Company’s procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with Management. The Board of directors has, on the recommendation of the Engineering, Reserves and Operations Committee, approved:

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- (b) the filing of Form 51-102F2 which is the report of the independent qualified reserves evaluator on the reserves data; and
- (c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) "Ernie Sapiiha"
Ernie Sapiiha
President & CEO

(signed) "Murray Stodalka"
Murray Stodalka
Vice President Operations & Engineering

(signed) "Jeffrey Smith"
Jeffrey Smith
Chairman of the Engineering, Reserves and Operations
Committee

(signed) "Mel Belich"
Mel Belich
Chairman of the Board

March 25, 2008

SCHEDULE C

CHARTER OF THE AUDIT, FINANCE AND RISK COMMITTEE

MANDATE OF THE COMMITTEE

The Audit, Finance and Risk Committee (the “**Committee**”) of the Board of directors (the “**Board**”) of Compton Petroleum Corporation (the “**Company**”) shall, as permitted by the Business Corporations Act (Alberta) (the “**ABCA**”) and the Articles and By-Laws of the Company, have the responsibility to oversee that management has applied due diligence in creating and maintaining an effective risk management and control framework. This framework should provide reasonable assurance that the financial, operational, and regulatory objectives of the Company are achieved and that the statutory responsibilities of the Board are discharged. The Committee fulfils its role on behalf of the Board, by overseeing:

1. the integrity of the Company’s financial statements, financial information and accounting, financial reporting (including MD&A, as hereinafter defined), and auditing processes;
2. the external auditor’s qualifications, independence, and performance;
3. the Company’s compliance with legal and regulatory requirements; and
4. risk management, management information systems, governmental legislation, and external business of the Company.

While the Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Committee to plan or conduct audits, to determine that the Company’s financial statements are complete, accurate, and in accordance with generally accepted accounting principles, or to certify the Company’s financial statements. Management is responsible for preparing the Company’s financial statements and the Company’s external auditor is responsible for auditing the annual financial statements and for reviewing the interim financial statements. The Committee shall however; assist the Board in overseeing that management and the external auditor fulfill their responsibilities in the Company’s financial reporting process.

The Committee has the authority to obtain independent outside accounting and other advisors as deemed appropriate to perform its duties and responsibilities. The Company shall provide appropriate funding to compensate the external auditor and any advisors that the Committee chooses to engage. The Committee is authorized to communicate directly with the external auditor to discuss and review specific issues as necessary.

The Committee will primarily fulfil its responsibilities by carrying out the activities enumerated in the following sections of this Charter. The Committee will report regularly to the Board regarding the execution of its duties and responsibilities.

In fulfilling its mandate, the Committee has the responsibility to, without limitation:

(A) Internal and Disclosure Controls

1. review the effectiveness and integrity of the Company’s system of disclosure controls and system of internal controls regarding finance, accounting, compliance, and ethics that management and the Board have established;

2. where the Committee considers it necessary and appropriate, set up and review an internal audit process and review any appointment or dismissal of senior internal audit personnel appointed in connection therewith;
3. review the evaluation of internal controls by the external auditor with management and the Company's subsequent follow-up to any identified weaknesses;
4. review, in conjunction with the Human Resources, Compensation, Environmental, Health and Safety Committee of the Board, the appointment of the Chief Financial Officer;
5. determine the appropriate resolution of conflicts of interest in respect of audit, finance, and risk matters properly directed to the Committee;
6. review with management and the external auditor:
 - (a) in conjunction with the report of the external auditor, the Company's audited annual financial statements, including related footnotes and management's discussion and analysis of financial conditions and results of operations ("MD&A") and quarterly financial statements,
 - (b) the significant accounting judgments and reporting principles, practices, and procedures applied by the Company in preparing its financial statements including any newly adopted accounting policies,
 - (c) significant changes to the audit plan, if any, and any serious disputes or difficulties with management encountered during the audit,
 - (d) the co-operation received by the external auditor during the audit, including access to all requested records, data and information,
 - (e) any correspondence with regulatory or governmental authorities which raises material issues regarding the Company's financial statements or accounting policies, and
 - (f) any other matters not described above that are required to be communicated by the external auditors to the Committee pursuant to applicable law and regulation;
7. obtain an explanation from management of all significant variances between comparative reporting periods. The Committee shall review all financial statements prior to their presentation to the Board for approval;
8. review and recommend for approval by the Board, all documents to be publicly disclosed, prior to their release, which contain audited or unaudited financial information. Such documents include any prospectuses, interim unaudited financial statements, year end audited financial statements, the annual report, the annual management proxy circular, the annual information form, all press releases, and disclosures made under MD&A;
9. review with management the procedures that exist for the review of financial information extracted or derived from financial statements which is publicly disclosed by the Company other than in the documents listed in section 8 above and periodically, at least annually, assess the adequacy of those procedures, as required by Multilateral Instrument 52-110, section 2.3;

10. review with management and the external auditor all off-balance sheet financing mechanisms being used by the Company, their risks, and the clear disclosure of those risks and all other material financial risks to the Company's business;
11. discuss with the Company's General Counsel, at least annually, legal and regulatory matters that may have a material impact on the financial statements;
12. review with the Chief Financial Officer and the Chief Executive Officer of the Company their respective disclosures made to the Committee during the certification process as required by Multilateral Instrument 52-109, and in addition:
 - (a) any significant deficiencies or material weaknesses in the design or operation of internal controls,
 - (b) any fraud involving management or other employees who have a significant role in the Company's internal controls,
 - (c) any other obligations arising from certification, and
 - (d) any significant changes in the internal controls;
13. review with management and the external auditor and as required by the Corporate Governance Committee, the Company's Code of Business Conduct and Ethics;
14. establish and maintain procedures for:
 - (a) the receipt, retention, and treatment of complaints received by the Company regarding the Company's accounting, internal accounting controls, or auditing matters, and
 - (b) the confidential and anonymous submission by Company employees of concerns regarding questionable accounting or auditing matters, and review all matters relating thereto; and
15. review with management the details of all transactions between the Company and parties related to the Company.

(B) Oversight of the External Auditor

1. recommend to the Board and to the Shareholders the nomination of the external auditor, who shall be a "Registered Public Accounting Firm" within the meaning of applicable securities legislation, for the purpose of preparing or issuing an auditor's report or performing other audit, review, or attestation services for the Company;
2. review the qualifications and independence of the external auditor during the year;
3. at least annually, obtain and review a report by the independent auditor describing the firm's internal quality control procedures; any material issues raised by the most recent internal quality-control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the firm, and any steps taken to deal with any such issues; and

(to assess the auditor's independence) all relationships between the independent auditor and the listed company;

4. maintain a clear understanding with the external auditor that it is to have an open and transparent relationship with the Committee and that it is to report directly to the Committee;
5. provide a scheduled opportunity to meet with the external auditor for full, frank and timely discussions of all material issues, without management present;
6. discuss with the external auditor the scope and timing of the audit work with particular reference to high risk areas or areas of Board concern;
7. inquire as to whether the audit partner receives compensation based on the audit partner procuring engagements to provide services other than audit, review, or attest services to the Company;
8. review all reportable events, including disagreements, unresolved issues, and consultations, as defined in National Instruments 51-102, on a routine basis, whether or not there is to be a change of external auditor;
9. review all issues and documentation related to a change of external auditor, including information to be included in the Change of Auditor Notice and documentation called for under National Instruments 51-102 and the planned steps for an orderly transition period;
10. appropriately supervise and evaluate the performance of the external auditor and lead audit partner, and report conclusions to the Board;
11. review and approve the Company's hiring policies regarding partners, employees, former partners, and former employees of the current and previous external auditors of the Company;
12. oversee the rotation of audit partners as required by applicable regulation and, in order to ensure continuing auditor independence, consider annually whether it is appropriate to adopt a policy of rotating the Company's external auditing firm on a regular basis;
13. pre-approve the nature of, and fees for, all audit, review, attestation, and significant non-audit services provided by the external auditor, prior to engagement, and disclose such pre-approvals in accordance with applicable securities law;
14. consider the effect of significant non-audit engagements on the independence of the external auditor; and
15. provide to the external auditor any information and explanations, and access to records, documents, books, accounts, and vouchers of the Company that are, in the opinion of the external auditor, necessary to make the examinations and reports required under legislation or regulation.

(C) Oversight of Financial Reporting and Accounting Policies

1. review with management and the external auditor significant financial reporting issues arising during the fiscal period and the methods of resolution;
2. prior to the issuance of the external auditor's report on the Company's financial statements, discuss the following with the external auditor:

- (a) all critical accounting policies and practices applied in the financial statements,
 - (b) all alternative accounting and disclosure treatments of financial information within generally accepted accounting principles that have been discussed with management, ramifications of the use of such alternate treatments and disclosures, and the treatment preferred by the external auditor, and
 - (c) other material written communications between the external auditor and management, such as the post audit or management letter and schedule of unadjusted differences;
3. inquire of the external auditor as to the quality of the Company's accounting estimates, discussing significant judgments made in connection with the preparation of the financial statements;
 4. review with management any proposed changes in major accounting policies, the impact and clear disclosure of significant risks and uncertainties, and key estimates and judgments of management that may be material to financial reporting;
 5. prepare such reports and letters or other disclosure documents as are required to be prepared by the Committee under applicable securities legislation; and
 6. review any notice received by the Committee with respect to an error or misstatement of which a director or officer becomes aware;

(D) Additional Duties and Responsibilities

1. review the appointments of any other key financial executives who are involved in the financial reporting process;
2. review derivative and hedging policies of the Company and make recommendations to the Board in respect of gas contracts, hedging agreements, and other similar financial transactions;
3. review risk assessment and risk management policies. Such review should include the Company's major financial and accounting risk exposures, the steps management has undertaken to control them, and the clear disclosure of such material risks as part of the Company's continuous disclosure requirements; and
4. review the amount and terms of any insurance to be obtained or maintained by the Company, including insurance with respect to potential liabilities incurred by the directors or officers in the discharge of their duties and responsibilities;

(E) General

The Committee also has the responsibility to:

1. with the approval of the Board or the Corporate Governance Committee of the Board retain and compensate independent advisors (including legal counsel), as deemed necessary by the Committee;
2. meet separately with senior management, employees or independent advisors in respect of audit, finance and risk matters, as deemed necessary by the Committee;

3. review and assess annually the adequacy of this Charter and recommend any approved changes to the Corporate Governance Committee and the Board;
4. annually evaluate the performance of the Committee and Committee Chair;
5. prepare the Committee's report or reports for publication in applicable disclosure documents, including the Audit Committee Report for publication in the annual Management Information Circular;
6. report regularly to the Board through the Chair of the Committee or through such other person appointed by the Committee the conclusions reached and issues considered by the Committee;
7. fulfill its responsibilities and duties by:
 - (a) inspecting any and all of the books, records, and financial affairs of the Company, its subsidiaries and affiliates, and
 - (b) meeting with any executive or employee of the Company with or without management to review such accounts, records and other matters as any member of the Committee considers necessary and appropriate;
8. review when deemed necessary by the Committee any of the financial affairs of the Company, its subsidiaries or affiliates and make recommendations to the Board, to the external auditor, or to management, as appropriate;
9. consider and make recommendations to the Board with respect to any matters properly referred to the Committee by the Board;
10. perform any other activities consistent with this Charter as the Committee deems necessary or appropriate in order to carry out its mandate.

COMPOSITION OF THE COMMITTEE

1. The Committee shall be comprised of at least three directors.
2. Each member of the Committee shall be "independent" as affirmatively determined by the Board, and as defined in the Company's Standards of Independence attached hereto.
3. At least half of the members of the Committee must be resident Canadians, as that term is defined in the ABCA.
4. The Board shall appoint the members of the Committee at the first meeting of the Board following each annual meeting ("**Annual Meeting**") of the shareholders of the Company.
5. The Board shall appoint one member of the Committee to be the Chair of the Committee.
6. A director appointed by the Board to the Committee shall be a member of the Committee until the next Annual Meeting or until his or her earlier resignation or removal by the Board. A member shall cease to be a member of the Committee upon ceasing to be a director of the Company.
7. The Board may remove or replace any member of the Committee at any time.

8. The Company's Corporate Secretary, or in his or her absence, one of the members chosen by the Committee shall be the Secretary of the Committee.
9. Members of the Committee may not serve on the audit committee of more than two additional public companies without the prior approval of the Board.
10.
 - (a) Each member of the Committee shall be financially literate. An individual is financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Company's financial statements;
 - (b) A Committee member who is not financially literate may be appointed to the Committee provided that the member becomes financially literate within a reasonable period of time following his or her appointment; and
 - (c) At least one member of the Committee shall have accounting or related financial management expertise and, where possible, at least one member of the Committee shall qualify as an "audit committee financial expert" within the meaning of applicable securities legislation.

MEETINGS OF THE COMMITTEE

1. The Committee shall convene at such times and places designated by the Chair of the Committee, at least on a quarterly basis, and whenever a meeting is requested by the Board, a member of the Committee, the external auditor, or a senior officer of the Company. The Committee shall meet in separate sessions with management and the external auditor at each regularly scheduled meeting.
2. Notice of each meeting of the Committee shall be given to each member and to the external auditor, who shall be entitled to attend each meeting of the Committee.
3. Notice of a meeting of the Committee shall:
 - (a) be in writing (which may be communicated by electronic facsimile or other communication facilities),
 - (b) state the nature of the business to be transacted at the meeting in reasonable detail,
 - (c) to the extent practicable, be accompanied by copies of documentation to be considered at the meeting, and
 - (d) be given at least 24 hours preceding the time stipulated for the meeting.
4. A quorum for the transaction of business at a meeting of the Committee shall consist of a majority of the members of the Committee.
5. A member of the Committee may participate in a meeting of the Committee by means of such telephonic, electronic, or other communication facilities as permit all persons participating in the meeting to communicate adequately with each other. A member participating in such a meeting by any such means is deemed to be present at that meeting.

6. In the absence of the Chair of the Committee, the members of the Committee shall choose one of the members present to be Chair of the meeting and, in the absence of the Secretary of the Committee; the members shall choose one of the persons present to be the Secretary of the meeting.
7. Management of the Company may attend meetings of the Committee as deemed appropriate by the Committee, and shall attend meetings of the Committee when requested to do so by the Committee.
8. Minutes shall be kept of all meetings of the Committee and shall be signed by the Chairman and Secretary of the meeting. The minutes shall be maintained with the Company's records, shall include copies of all resolutions passed at each meeting, and shall be available for review by members of the Committee, the Board, Management and external auditor.

COMPTON PETROLEUM CORPORATION STANDARDS OF INDEPENDENCE

Compton Petroleum Corporation (“**Compton**” or the “**Company**”) has adopted the following standards for determining whether a director is independent within the meaning of applicable Canadian and United States securities laws and the New York Stock Exchange corporate governance rules.

These Standards will be periodically reviewed and may be modified by Compton’s Board of directors (the “**Board**”). Except where required by applicable law or the rules of the New York Stock Exchange, the criteria set forth in these standards are not intended to constitute rigid rules that govern the Board’s determination of whether a director is independent from the Company or an interpretation of any applicable law, rule or regulation.

To be considered independent for purposes of these standards, the Board must affirmatively determine on an annual basis that the director being reviewed has no direct or indirect material relationship with the Company. A “**material relationship**” is a relationship which could, in the view of the Company’s Board, be reasonably expected to interfere with the exercise of a member’s independent judgment. In each case, the Board shall consider all relevant facts and circumstances.

Additionally, a director will not be deemed to be independent if:

- (a) the director is, or has been within the last three years, an employee or executive officer of the Company, or an immediate family member¹ of the director is, or has been within the last three years, an executive officer of the Company;
- (b) the director is a current partner or employee of a firm that is the Company’s internal or external auditor, or was within the last three years, a partner² or employee of that firm and personally worked on the Company’s audit within that time;
- (c) an immediate family member of the director is a current partner of a firm that is the Company’s internal or external auditor, or is a current employee of that firm and participates in its audit, assurance or tax compliance (but not tax planning) practice, or was, within the last three years a partner or employee of that firm and personally worked on the Company’s audit within that time;
- (d) the director, or an immediate family member of the director, is or has been within the last three years, an executive officer of an entity on which any of the Company’s current executive officers serves or served at that same time on the entity’s compensation committee;
- (e) the director or an immediate family member of the director who is employed as an executive officer of the Company has received, during any twelve month period within the last three years, more than \$75,000 in direct compensation from the Company, other than 1) director and committee fees, 2) pension or other forms of deferred compensation for prior service provided that such compensation is not contingent in any way on continued service and 3) compensation for previously acting as an interim chief executive officer of the Company or previously acting as a chairman of the board on a part-time basis;

¹ An immediate family member is defined as a director’s spouse, parents, children, siblings, mothers and fathers-in-law, sons and daughters-in-law, brothers and sisters-in-law, and anyone (other than domestic employees) who shares the director’s home.

² A partner does not include a fixed income partner whose interest in the firm that is the internal or external auditor is limited to the receipt of fixed amounts of compensation (including deferred compensation) for prior service with that firm if the compensation is not contingent in any way on continued service.

- (f) the director is a current employee, or an immediate family member is a current executive officer, of a company that has made payments to, or received payments from, the Company for property or services in an amount which, in any of the last three fiscal years, exceeds the greater of \$1 million, or 2% of such other company's consolidated gross revenues;
- (g) the director accepts, directly or indirectly, any consulting, advisory or other compensatory fee from the Company or any subsidiary entity of the Company, other than as remuneration for acting in the director's capacity as a member of the board or any board committee, or as a part-time chair or vice-chair of the board or any board committee; or is an affiliated entity of the Company or any of its subsidiary entities.

Other compensatory fees includes acceptance of a fee by an immediate family member or an entity in which the director is a partner, member, an officer such as a managing director occupying a comparable position or executive officer, or occupies a similar position (except limited partners, non-managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity) and which provides accounting, consulting, legal, investment banking or financial advisory services to the Company or any subsidiary entity of the Company. Compensatory fees do not include the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the Company if the compensation is not contingent in any way on continued service.

- (h) the director is an affiliated³ person of the Company.

³ Affiliated person of another person means:

- (a) any person directly or indirectly owning, controlling, or holding with power to vote, 5% or more of the outstanding voting securities of such other person;
- (b) any person 5% or more of whose outstanding voting securities are directly or indirectly owned, controlled, or held with power to vote, by such other person;
- (c) any person directly or indirectly controlling, controlled by, or under common control with, such other person;
- (d) any officer, director, partner, copartner, or employee of such other person;
- (e) if such other person is an investment company, any investment adviser thereof or any member of an advisory board thereof; and
- (f) if such other person is an unincorporated investment company not having a board of directors, the depositor thereof.