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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

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SECTION

ORIGINAL

Amendment No. 1
to
Form CB

TENDER OFFER/RIGHTS OFFERING NOTIFICATION FORM

Please place an X in the box(es) to designate the appropriate rule provision(s) relied upon to file this Form:

Securities Act Rule 801 (Rights Offering) [ ]

Securities Act Rule 802 (Exchange Offer) [X]

Exchange Act Rule 13e-4(h)(8) (Issuer Tender Offer) [ ]

Exchange Act Rule 14d-1(c) (Third Party Tender Offer) [ ]

Exchange Act Rule 14e-2(d) (Subject Company Response) [ ]

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FINANCIAL

Meridian Energy Corporation
(Name of Subject Company)

N/A
(Translation of Subject Company's Name into English (if applicable))

Alberta
(Jurisdiction of Subject Company's Incorporation or Organization)

True Energy Inc.
(Name of Person(s) Furnishing Form)

Common Shares
(Title of Class of Subject Securities)

58960K
(CUSIP Number of Class of Securities (if applicable))

Torys LLP
237 Park Avenue
New York, New York 10017
Attention: Andrew J. Beck
(212) 880-6000
(Name, Address (including zip code) and Telephone Number (including area code) of Person(s) Authorized to Receive Notices and Communications on Behalf of Subject Company)

February 7, 2005
(Date Tender Offer/Rights Offering Commenced)

PART I

INFORMATION SENT TO SECURITY HOLDERS

Item 1. **Home Jurisdiction Documents**

- *Offer to Purchase and Take-over Bid Circular of True Energy Inc. ("True Energy"), dated February 7, 2005 (the "Circular")
- *Letter of Transmittal for Meridian Shareholders
- *Notice of Guaranteed Delivery for Meridian Shareholders
- Notice of Change, dated March 4, 2005

*Previously furnished.

Item 2 **Informational Legends**

See the cover page of the Circular.

2

This document is important and requires your immediate attention. It should be read in conjunction with the Offer to Purchase and accompanying Circular of True Energy Inc. dated February 7, 2005. If you are in any doubt as to how to deal with it, you should consult your investment dealer, stockbroker, bank manager, lawyer or other professional advisor.

March 4, 2005

NOTICE OF CHANGE TO TAKE-OVER BID CIRCULAR of TRUE ENERGY INC. in respect of its OFFER TO PURCHASE all of the Common Shares of MERIDIAN ENERGY CORPORATION

This Notice of Change (the "Notice") supplements the Offer to Purchase (the "Offer to Purchase") and the accompanying take-over bid circular (the "Circular") dated February 7, 2005 of True Energy Inc. ("True") pursuant to which True is offering to purchase all of the outstanding common shares ("Meridian Shares") of Meridian Energy Corporation ("Meridian") on the terms and conditions set forth in the Offer to Purchase, the Circular and the related Letter of Transmittal and Notice of Guaranteed Delivery (collectively, the "Original Offer").

Except as otherwise set forth in this Notice, the information, terms and conditions contained in the Original Offer continue to be applicable in all respects and this Notice should be read in conjunction with the Original Offer. Unless the context requires otherwise, terms not defined herein have the meanings set forth in the Original Offer. The term "Offer" means the Original Offer, as supplemented by this Notice.

The Offer is open for acceptance until 4:30 p.m. (Calgary time) on March 15, 2005, unless extended or withdrawn.

The board of directors of Meridian has unanimously recommended that shareholders of Meridian accept the Offer. Meridian's financial advisor, Tristone Capital Inc., has expressed an opinion to the board of directors of Meridian that the consideration to be received by the holders of Meridian Shares pursuant to the Offer is fair, from a financial point of view, to holders of Meridian Shares. For further information, refer to the Directors' Circular of the board of directors of Meridian.

Holders of Meridian Shares who wish to accept the Offer must properly complete and execute the Letter of Transmittal provided with the Offer or a manually executed facsimile thereof and deposit it, together with the certificate or certificates representing their Meridian Shares, at the offices of Computershare Trust Company of Canada (the "Depositary") shown in the Letter of Transmittal and on the last page of this document, in accordance with the instructions in the Letter of Transmittal. Alternatively, a holder of Meridian Shares who desires to deposit such shares and whose certificate or certificates for such shares are not immediately available may deposit such certificate or certificates by following the procedures for guaranteed delivery set forth in Section 3 of the Offer, "Manner of Acceptance".

Questions and requests for assistance may be directed to the Depositary and additional copies of this Notice, the Offer to Purchase, the Circular, the Letter of Transmittal and Notice of Guaranteed Delivery, as well as documents incorporated by reference therein, may be obtained upon request without charge from those persons at their respective offices shown in the Letter of Transmittal and on the last page of this document. Persons whose Meridian Shares are registered in the name of a nominee should contact their stockbroker, investment dealer, bank, trust company or other nominee for assistance in depositing their Meridian Shares.

TRUE ENERGY INC.

NOTICE OF CHANGE TO TAKE-OVER BID CIRCULAR

TO: SHAREHOLDERS OF MERIDIAN ENERGY CORPORATION

This Notice of Change (the "Notice") supplements the Offer to Purchase (the "Offer to Purchase") and the accompanying take-over bid circular (the "Circular") dated February 7, 2005 of True pursuant to which True is offering to purchase all of the issued and outstanding common shares ("Meridian Shares") of Meridian Energy Corporation ("Meridian") on the terms and conditions set forth in the Offer to Purchase, the Circular and the related Letter of Transmittal and Notice of Guaranteed Delivery (collectively, the "Original Offer").

Except as otherwise set forth in this Notice, the information, terms and conditions contained in the Original Offer continue to be applicable in all respects and this Notice should be read in conjunction therewith. All capitalized terms used herein and not specifically defined herein shall have the meanings set forth in the Original Offer unless the context otherwise requires. The term "Offer" means the Original Offer, as supplemented by this Notice.

BACKGROUND TO AND DETAILS OF CHANGE

The Original Offer was mailed to holders of Meridian Shares on February 7, 2005. Following the time of mailing of the Original Offer, True received a report from Gilbert Laustsen Jung Associates Ltd. ("GLJ") dated March 3, 2005 evaluating the crude oil, natural gas liquids and natural gas reserves of True as at December 31, 2004. Accordingly, on March 4, 2005 True filed its statement of reserves data and other oil and gas information (the "Statement of Reserves") dated March 4, 2005 with the provincial securities commissions or similar authorities in Canada. The effective date of the Statement of Reserves is December 31, 2004. A copy of the Statement of Reserves may be obtained by accessing the disclosure documents available for True through the Internet on the Canadian System for Electronic Document Analysis and Retrieval ("SEDAR") website at www.sedar.com. True's SEDAR profile number is 14985.

As a result of True's filing of its Statement of Reserves, the Circular is hereby amended such that the Statement of Reserves shall be deemed to be incorporated by reference into and form an integral part of the Circular. Specifically, the Circular is amended as follows:

1. Under the heading "True Energy Inc. – Documents Incorporated by Reference" an additional paragraph (i) is added at the end of the first paragraph as follows:

   "(i) the Statement of Reserves Data and Other Oil and Gas Information of True dated March 4, 2005".

CONSEQUENTIAL AMENDMENTS

Consequential amendments in accordance with this Notice are deemed to be made where required to the Offer to Purchase, the Circular, the Letter of Transmittal and the Notice of Guaranteed Delivery. Except as varied by this Notice, all terms of the Original Offer remain in effect, unamended.

STATUTORY RIGHTS

Securities legislation in certain of the provinces and territories of Canada provides Shareholders with, in addition to any other rights they may have at law, rights of rescission or to damages, or both, if there is misrepresentation in a circular or notice that is required to be delivered to the Shareholders. However, such rights must be exercised within prescribed time limits. Shareholders should refer to the applicable provisions of the securities legislation of their province or territory for particulars of those rights or consult with a lawyer.

APPROVAL AND CERTIFICATE

The contents of this Notice of Change have been approved, and the sending, communication or delivery thereof to the Shareholders has been authorized by the board of directors of True Energy Inc.

The Offer to Purchase and Circular as it has been supplemented and amended by this Notice, contains no untrue statement of a material fact and does not omit to state a material fact that is required to be stated or that is necessary to make a statement not misleading in the light of the circumstances in which it was made.

DATED at Calgary, Alberta, this 4th day of March, 2005.

(signed) "*Paul R. Baay*"
President and Chief Executive Officer

(signed) "*Joan E. Dunne*"
Vice President, Finance and Chief Financial Officer

On behalf of the Board of Directors

(signed) "*Kenneth P. Acheson*"
Director

(signed) "*John H. Cuthbertson*"
Director

6

The Depositary for the Offer is:

COMPUTERSHARE TRUST COMPANY OF CANADA

By Mail:

P.O. Box 7021
31 Adelaide St. E.
Toronto, Ontario M5C 3H2
Attention: Corporate Actions

By Hand, by Courier or by Registered Mail:

Toronto
100 University Avenue, 9th Floor
Toronto, Ontario M5J 2Y1
Attention: Corporate Actions

OR

Calgary
Watermark Tower, Suite 600, 530- 8th Avenue S.W.
Calgary, Alberta T2P 3S8

Toll Free: 1-800-564-6253
Email: service@computershare.com

Any questions and requests for assistance may be directed by Shareholders to the Depositary at the telephone numbers and locations set out above.

PART II

INFORMATION NOT REQUIRED TO BE SENT TO SECURITY HOLDERS

See the Exhibit Index to this Amendment No. 1 to Form CB.

PART III

CONSENT TO SERVICE OF PROCESS

A written irrevocable consent and power of attorney on Form F-X was filed by True Energy Inc. concurrently with the Form CB filed on February 8, 2005.

PART IV

After due inquiry and to the best of my knowledge and belief, I certify that the information set forth in this statement is true, complete and correct as of March 4, 2005.

True Energy Inc.

By: ______________________

Name: Joan E. Dunne
Title: Vice President, Finance and Chief Financial Officer

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EXHIBIT INDEX

Exhibit	Description
*2.1	Revised Initial Annual Information Form of True Energy dated May 12, 2004 for the year ended December 31, 2003, including management' discussion and analysis incorporated by reference therein;
*2.2	Information Circular - Proxy Statement of True Energy dated March 31, 2004 relating to the annual and special meeting of True Energy shareholders held on May 20, 2004 (excluding the disclosure under the headings "Report of Compensation Committee", "Performance Graph" and "Corporate Governance Practices");
*2.3	Audited comparative consolidated financial statements of True Energy for the years ended December 31, 2003 and 2002, together with the notes thereto and the auditors' report thereon, contained in True Energy's 2003 Annual Report;
*2.4	Unaudited interim comparative consolidated financial statements of True Energy for the three and nine months ended September 30, 2004 and management's discussion and analysis of financial condition and results of operations for the three and nine months ended September 30, 2004;
*2.5	Material Change Report of True Energy dated April 7, 2004 in respect of the private placement of 4,457,153 common shares and 2,558,140 common shares of True Energy issued on a flow-through basis;
*2.6	Material Change Report of True Energy dated January 25, 2005 in respect of the proposed acquisition of Meridian by True Energy;
*2.7	Audited comparative financial statements of Meridian for the years ended December 31, 2003, 2002 and 2001, together with the notes thereto and the auditors' report thereon; and
*2.8	Unaudited interim comparative financial statements of Meridian for the nine months ended September 30, 2004.
2.9	Statement of reserves data and other oil and gas information of True Energy for the year ended December 31, 2004

*Previously furnished.

EXHIBIT 2.9

TRUE ENERGY INC.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

March 4, 2005

13

TABLE OF CONTENTS

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbls	barrels
Mbbls	thousand barrels
BOPD	barrels of oil per day
Bbls/d	barrels of oil per day
MMbbls	million barrels
NGLs	natural gas liquids
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 Bbl of crude oil for 6 Mcf of natural gas

Natural Gas

Mcf	thousand cubic feet
Mmcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
Mmcf/d	million cubic feet per day
m^3	cubic metres
MMBTU	million British Thermal Units
gigajoule	trillion joules
Boe/d	barrels of oil equivalent per day

Other

AECO	EnCana Corp.'s natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale.
ARTC	Alberta Royalty Tax Credit
BOE/d	barrel of oil equivalent per day
MBOE	1,000 barrels of oil equivalent
$000s or $M	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSIONS

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

CERTAIN DEFINITIONS

In this Statement, the following words and phrases have the following meanings, unless the context otherwise requires:

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**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 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, pumping equipment and wellhead assembly;

(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 wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"**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 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;

(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.

"**GLJ**" means Gilbert Laustsen Jung Associates Ltd.;

"**GLJ Report**" means the report of GLJ dated March 3, 2005 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2004;

"**Gross**" means:

(a) in relation to the Corporation's interest in production and reserves, its "Corporation gross reserves", which are the Corporation's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;

(b) in relation to wells, the total number of wells in which the Corporation has an interest; and

(c) in relation to properties, the total area of properties in which the Corporation has an interest.

"**Net**" means:

(a) in relation to the Corporation's interest in production and reserves, the Corporation's interest (operating and non-operating) share after deduction of royalties obligations, plus the Corporation's royalty interest in production or reserves.

(b) in relation to wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

(c) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

"**NI 51-101**" means National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities;

"**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.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Unless otherwise specified, information in this Statement is as at the end of the Corporation's most recently completed financial year, being December 31, 2004.

All dollar amounts herein are in Canadian dollars, unless otherwise stated.

The statement of reserves data and other oil and gas information provided herein (the "Statement") is dated March 4, 2005. The effective date of the Statement is December 31, 2004 and the preparation date of the Statement is March 3, 2005.

FORWARD-LOOKING STATEMENTS

Some of the statements contained herein including, without limitation, financial and business prospects and financial outlooks may be forward-looking statements which reflect management's expectations regarding future plans and intentions, growth, results of operations, performance and business prospects and opportunities. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions have been used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, changes in general economic and market conditions and other risk factors. Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances.

Forward-looking statements and other information contained herein concerning the oil and gas industry and the Corporation's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

DISCLOSURE OF RESERVES DATA

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by GLJ with an effective date of December 31, 2004 contained in the GLJ Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Corporation engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Corporation's reserves are in Canada and, specifically, in the provinces of Alberta and Saskatchewan.

The Report of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by the Independent Qualified Reserves Evaluator are attached as Appendix A hereto.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Corporation's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Reserves Data (Constant Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2004
CONSTANT PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mmcf)	Net (Mmcf)	Gross (Mbbl)	Net (Mbbl)
PROVED								
Developed Producing	288	300	2,136	1,813	29,916	24,471	181	151
Developed Non-Producing	96	80	93	84	4,896	3,983	31	24
Undeveloped	-	-	154	134	5,362	4,659	50	44
TOTAL PROVED	384	379	2,384	2,031	40,174	33,114	262	219
PROBABLE	95	92	1,018	869	17,806	14,565	76	63
TOTAL PROVED PLUS PROBABLE	479	472	3,401	2,900	57,980	47,679	338	282

NET PRESENT VALUES OF FUTURE NET REVENUE ($000s)

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/ year) 0	5	10	15	20	AFTER INCOME TAXES DISCOUNTED AT (%/ year) 0	5	10	15	20
PROVED										
Developed Producing	145,523	123,969	108,962	97,848	89,237	123,125	104,352	91,442	81,966	74,671
Developed Non-Producing	21,786	18,215	15,617	13,660	12,139	13,376	10,870	9,028	7,627	6,530
Undeveloped	17,372	12,336	9,069	6,832	5,232	10,666	7,361	5,243	3,815	2,814
TOTAL PROVED	184,681	154,520	133,648	118,340	106,608	147,167	122,583	105,713	93,408	84,015
PROBABLE	76,042	53,863	40,793	32,345	26,498	47,390	32,901	24,459	19,031	15,283
TOTAL PROVED PLUS PROBABLE	260,723	208,383	174,441	150,685	133,106	194,557	155,484	130,172	112,439	99,298

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) as of December 31, 2004 CONSTANT PRICES AND COSTS ($000s)

RESERVES CATEGORY	REVENUE	ROYALTIES	OPERATING COSTS	CAPITAL DEVELOPMENT COSTS	WELL ABANDONMENT COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
Proved Reserves	340,256	71,504	68,046	11,341	4,684	184,681	37,515	147,167
Proved Plus Probable Reserves	484,006	101,088	97,658	19,100	5,437	260,723	66,166	194,557

FUTURE NET REVENUE BY PRODUCTION GROUP as of December 31, 2004 CONSTANT PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	4,042
	Heavy Oil (including solution gas and other by-products)	11,976
	Natural Gas (including by-products but excluding solution gas from oil wells)	116,156
	Other company revenue costs	1,474
	Total	133,648
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	4,647
	Heavy Oil (including solution gas and other by-products)	16,032
	Natural Gas (including by-products but excluding solution gas from oil wells)	151,983
	Other company revenue costs	1,779
	Total	174,441

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2004
FORECAST PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mmcf)	Net (Mmcf)	Gross (Mbbl)	Net (Mbbl)
PROVED								
Developed Producing	267	274	2,234	1,881	29,764	24,361	180	151
Developed Non-Producing	96	80	84	76	4,831	3,934	31	24
Undeveloped	-	-	161	136	5,358	4,657	50	44
TOTAL PROVED	363	353	2,479	2,092	39,953	32,951	262	219
PROBABLE	86	83	1,049	880	17,690	14,482	76	63
TOTAL PROVED PLUS PROBABLE	449	436	3,529	2,972	57,643	47,434	338	282

	NET PRESENT VALUES OF FUTURE NET REVENUE ($000s)									
	BEFORE INCOME TAXES DISCOUNTED AT (%/ year)					AFTER INCOME TAXES DISCOUNTED AT (%/ year)				
RESERVES CATEGORY	0	5	10	15	20	0	5	10	15	20
PROVED										
Developed Producing	142,112	123,425	109,962	99,733	91,651	120,399	103,748	91,935	83,071	76,136
Developed Non-Producing	19,468	16,534	14,341	12,654	11,324	11,950	9,823	8,225	6,988	6,006
Undeveloped	14,598	10,562	7,880	6,007	4,645	8,960	6,275	4,519	3,318	2,464
TOTAL PROVED	176,177	150,521	132,183	118,395	107,620	141,309	119,846	104,679	93,377	84,606
PROBABLE	70,252	50,772	39,044	31,333	25,922	43,966	31,029	23,372	18,384	14,903
TOTAL PROVED PLUS PROBABLE	246,430	201,293	171,227	149,728	133,542	185,275	150,875	128,051	111,761	99,509

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2004
FORECAST PRICES AND COSTS
($000s)

RESERVES CATEGORY	REVENUE	ROYALTIES	OPERATING COSTS	CAPITAL DEVELOPMENT COSTS	WELL ABANDONMENT COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
Proved Reserves	341,242	72,673	75,347	11,398	5,647	176,177	34,869	141,309
Proved Plus Probable Reserves	486,250	102,538	111,140	19,224	6,918	246,430	61,154	185,275

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2004
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/ year) ($000)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	3,429
	Heavy Oil (including solution gas and other by-products)	20,314
	Natural Gas (including by-products but excluding solution gas from oil wells)	107,047
	Other company revenue costs	1,393
	Total	132,183
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	3,926
	Heavy Oil (including solution gas and other by-products)	26,670
	Natural Gas (including by-products but excluding solution gas from oil wells)	138,942
	Other company revenue costs	1,689
	Total	171,227

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the GLJ Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, specifically the forecast prices and costs and constant prices and costs.

Reserves are classified according to the degree of certainty associated with the estimates.

(a) **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.

(b) **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.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(c) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

  (i) **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 certainly.

  (ii) **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.

(d) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, 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 classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

3. **Forecast Prices and Costs**

Forecast prices and costs are those:

(a) generally acceptable 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 Corporation 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).

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

The forecast cost and price assumptions assume primarily decreases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the GLJ Report were GLJ's price forecast as at January 1, 2005 which is as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

Year	OIL[1] WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40° API ($Cdn/ Bbl)	Hardisty Heavy 12° API ($Cdn/ Bbl)	Cromer Medium 29.3° API ($Cdn/ Bbl)	NATURAL GAS AECO Gas Price ($Cdn/ MMBtu)	NATURAL GAS LIQUIDS Edmonton Propane ($Cdn/Bbl)	NATURAL GAS LIQUIDS Edmonton Butane ($Cdn/Bbl)	INFLATION RATES[1] %/ Year	EXCHANGE RATE[2] ($US/ $Cdn)
Forecast									
2005	42.00	50.25	27.50	43.75	6.60	32.25	37.25	2.0	0.820
2006	40.00	47.75	28.50	41.50	6.35	30.50	35.25	2.0	0.820
2007	38.00	45.50	28.75	39.50	6.15	29.00	33.75	2.0	0.820
2008	36.00	43.25	27.25	37.75	6.00	27.75	32.00	2.0	0.820
2009	34.00	40.75	25.50	35.50	6.00	26.00	30.25	2.0	0.820
2010	33.00	39.50	24.75	34.25	6.00	25.25	29.25	2.0	0.820
2011	33.00	39.50	24.75	34.25	6.00	25.25	29.25	2.0	0.820
2012	33.00	39.50	24.75	34.25	6.00	25.25	29.25	2.0	0.820
2013	33.50	40.00	24.75	34.75	6.10	25.50	29.50	2.0	0.820
2014	34.00	40.75	25.50	35.50	6.20	26.00	30.25	2.0	0.820
2015	34.50	41.25	25.75	36.00	6.30	26.50	30.50	2.0	0.820
2016+	+2%/ yr	+2%/ yr	+2%/ yr	+2%/ yr	+ 2%/ yr	+ 2%/ yr	+ 2%/ yr	+ 2%/ yr	0.820

Notes:

(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by the Corporation for the year ended December 31, 2004, were $6.65/Mcf for natural gas, $50.21/Bbl for light and medium gravity crude oil, $28.29/Bbl for heavy oil and $36.52/Bbl for NGLs.

4. **Constant Prices and Costs**

Constant prices and costs are:

(a) the Corporation's prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies; and

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation 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).

For the purposes of paragraph (a), the Corporation's prices are the posted prices for oil and the spot price for gas, after historical adjustments for transportation, gravity and other factors.

The constant crude oil and natural gas benchmark references pricing and the exchange rate utilized in the GLJ Report were as follows:

SUMMARY OF PRICING ASSUMPTIONS
CONSTANT PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40° API ($Cdn/Bbl)	Hardisty Heavy 12° API ($Cdn/Bbl)	NATURAL GAS AECO Gas Price ($Cdn/MMBtu)	EXCHANGE RATE[1] ($US/$Cdn)
Historical					
2004[2]	43.45	46.54	24.33	6.79	0.8308

24

Notes:

(1) The exchange rate used to generate the benchmark reference prices in this table.
(2) As at December 31.

5. The ARTC is included in the cumulative cash flow amounts. ARTC is based on the program announced January 1990 by the Alberta government with modifications effective January 1, 1995. In 2004, the Corporation did not qualify for the maximum ARTC.

6. Estimated future abandonment and reclamation costs related to a property have been taken into account by GLJ in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs. No allowance was made, however, for reclamation of well sites or the abandonment and reclamation of any facilities.

7. Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.

8. The extent and character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.

RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE

RECONCILIATION OF
COMPANY NET RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL			CONVENTIONAL NATURAL GAS		
FACTORS	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (Mmcf)	Net Probable (Mmcf)	Net Proved Plus Probable (Mmcf)
January 1, 2004[1]	251	43	294	1,205	670	1,875	15,675	4,893	20,568
Extensions	-	-	-	164	216	380	900	1,900	2,800
Improved Recovery	8	2	10	959	13	972	12,100	3,500	15,600
Technical Revisions	24	5	29	(111)	(107)	(217)	954	589	1,543
Discoveries	76	19	95	189	42	231	8,400	3,400	11,800
Acquisitions	19	3	22	111	28	139	600	200	800
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	26	11	37	35	17	52	46	1	47
Production	(52)	-	(52)	(460)	-	(460)	(5,724)	-	(5,724)
December 31, 2004	353	83	436	2,092	880	2,972	32,951	14,483	47,434

Note: The Corporation has no unconventional reserves (Bitumen, Synthetic Crude Oil, Natural Gas from Coal, etc.)

RECONCILIATION OF CHANGES IN
NET PRESENT VALUES OF FUTURE NET REVENUE
DISCOUNTED AT 10% PER YEAR
PROVED RESERVES
CONSTANT PRICES AND COSTS

PERIOD AND FACTOR	After Tax 2004 (M$)	Before Tax 2004 (M$)
Estimated Net Present Value of Future Net Revenue at January 1, 2004	51,031	68,335
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties (1)	(37,807)	(37,807)
Net Change in Prices, Production Costs and Royalties Related to Forecast Future Production (2)	4,496	4,496
Changes in Previously Estimated Development Costs Incurred During the Period (3)	47,160	47,160
Changes in Estimated Future Development Costs (4)	(56,162)	(56,162)
Extensions and Improved Recovery (5)	43,476	43,476
Discoveries (5)	31,481	31,481
Acquisitions of Reserves (5)	3,022	3,022
Dispositions of Reserves (5)	-	-
Net Change Resulting from Technical Reserves Revisions	6,474	6,474
Accretion of Discount (6)	6,834	6,834
Net Change in Income Taxes (7)	(18,931)	-
All Other Changes	24,639	16,339
Estimated Net Present Value of Future Net Revenue at December 31, 2004	105,713	133,648

Notes:

(1) Corporation actual before income taxes, excluding general and administrative expenses.
(2) The impact of changes in prices and other economic factors on future net revenue.
(3) Actual capital expenditures relating to the exploration, development and production of oil and gas reserves.
(4) The change in forecast development costs for the properties evaluated at the beginning of the period.
(5) End of period net present value of the related reserves.
(6) Estimated as 10% of the beginning of period net present value.
(7) The difference between forecast income taxes at beginning of period and the actual taxes for the period plus forecast income taxes at the end of the period.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Proved Undeveloped Reserves

The Corporation had proved undeveloped reserves attributed to 30 future wells in the GLJ Report. A total of 5,358 Mmcf of natural gas, 161 Mbbl of heavy oil and 50 Mbbl of NGL's were assigned as gross proved undeveloped reserves, approximately 11% of the Corporation's total proved reserves.

Twenty-seven of these wells, representing approximately 85% of the assigned proved undeveloped reserves, are located in the Corporation's Dodsland Viking gas development area. Four of the these wells have now been drilled while the remaining 23 are part of the planned ongoing 2005 drilling program in this development, ultimately expected to be in the order of 50 additional wells.

The other three wells, representing approximately 15% of the assigned proved undeveloped reserves are in the Corporation's Smiley heavy oil area. A total of nine Smiley heavy oil wells, including these wells, are scheduled for drilling in 2005.

Probable Undeveloped Reserves

A total of 3,299 Mmcf of natural gas, 504 Mbbl of heavy oil and 10 Mbbl of NGL's gross probable undeveloped reserves, representing approximately 26% of the Corporation's total probable reserves or 8% of total proved plus probable reserves, were attributed to 20 future wells.

Fourteen of these wells, representing approximately 12% of the total probable reserves, are in the Corporation's Dodsland Viking gas development area. One of these wells has now been drilled and the remaining 13 are part of the planned ongoing development drilling program referred to above under "Proved Undeveloped Reserves".

One gas well and three heavy oil wells, representing approximately 6% of the Corporation's total probable reserves, are in the Smiley area. The gas well is part of the Corporation's 2005 drilling program and, as mentioned under "Proved Undeveloped Reserves", a total of nine heavy oil wells are planned for this area.

Two heavy oil wells, representing approximately 8% of total probable reserves, are in the Corporation's Kerrobert McLaren area and are planned for the second half of 2005.

In addition, a total of 1,186 Mmcf of natural gas, 37 Mbbl of heavy oil and 14 Mbbl of NGL's gross probable undeveloped reserves, representing approximately 6% of total probable reserves or 2% of total proved plus probable reserves, were assigned as additional recovery to the 30 planned wells mentioned above under "Proved Undeveloped Reserves".

Significant Factors or Uncertainties

The Corporation does not anticipate any significant economic factors or significant uncertainties will affect any particular components of the reserves data. However, the reserves can be affected significantly by fluctuations in product pricing, including heavy oil differentials, capital expenditures, operating costs, royalty regimes, and well performance that are beyond the Corporation's control.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below (in $M).

	Forecast Prices and Costs		Constant Prices and Costs	
Year	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
2005	10,637	17,859	10,637	17,860
2006	179	392	175	384
2007	-	34	-	33
2008	106	190	100	179
2009	-	24	-	23
Thereafter	476	725	429	621
Total Undiscounted	11,398	19,224	11,341	19,100
Total Discounted at 10%	10,646	17,895	10,612	17,836

The Corporation expects to be able to fund its capital expenditure program, including estimated future development costs, using cash flow from operations and forecasted credit facilities. Equity financing may also be used to fund operations. If cash flows are other than projected, capital expenditure levels will be adjusted to meet the targeted ratio. The Corporation's practices of continually monitoring spending opportunities in comparison to expected cash flow levels allow for adjustments to the capital program as required.

The Corporation does not expect that the costs of funding its capital expenditures will have a material effect of the economics of the programs.

OTHER OIL AND GAS INFORMATION

Principal Oil and Gas Properties

The following is a description of True's oil and natural gas properties as at December 31, 2004. Production stated is gross production to True (being the Corporation's working interest before royalties, as defined under "Gross") and, unless otherwise stated, is average production for 2004. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2004.

On January 20, 2005, the Corporation announced that it had entered into an agreement with Meridian Energy Corporation pursuant to which the Corporation would make an offer to acquire all of the outstanding common shares of Meridian on the basis of, at the election of the Meridian shareholder, (a) 0.91 common shares of True per Meridian share; or (b) $3.85 in cash per Meridian share; or (c) a combination thereof, provided that the maximum aggregate amount of cash payable pursuant to the offer ("Offer") shall be limited to $30 million. The Offer was dated February 7, 2005, and is subject to certain conditions, including the deposit of not less than 66 2/3% of the outstanding Meridian shares (on a fully diluted basis), receipt of all required regulatory approvals and other customary conditions. The offer expires on March 15, 2005, unless extended. This document discusses True's properties alone.

In 2005, True anticipates drilling approximately 90 wells, with approximately 20 wells in Alberta and the remainder in Saskatchewan. Capital spending in 2005 will be dependent upon the outcome of the currently outstanding Offer to purchase Meridian. If the Offer is successful, True's capital program will be re-evaluated in light of the drilling opportunities on the Meridian lands.

West Central Saskatchewan

When True Energy began operations on September 1, 2000 in west central Saskatchewan, production averaged 354 BOE/d. Since that time, the Corporation has expanded its operations through conventional drilling, farm-in agreements, asset and corporate acquisitions, and successful bidding at crown land sales. During 2004, True drilled 66 (62.0 net) wells in the province, with a 98% net success rate. By the end of 2004, True had accumulated a total of 73,051 net developed and 152,864 net undeveloped acres. In 2004, True produced an average of 4,245 BOE/d from Saskatchewan, weighted 61% towards natural gas. In the first two months of 2005, based on field estimates, True's Saskatchewan production averaged approximately 5,200 BOE/d, weighted 59% towards natural gas.

Kerrobert, Saskatchewan

Kerrobert is located approximately 40 kilometers north of the town of Kindersley, Saskatchewan. The property consists of 4,872 gross (2,386 net) developed acres and 8,615 gross (7,856 net) undeveloped acres of land. Kerrobert was the most significant producing area for True in 2004, representing 23% of total production. The Kerrobert area produces 35 degree API light oil from the Viking formation and 11 degree API heavy oil from the McLaren formation. In the area, the Corporation has 15 (15.0 net) producing crude oil wells from the McLaren channel and 96 (32.6 net) producing crude oil wells from the Viking zone. During 2004, sales of light crude oil averaged 86 Bbls/d, heavy oil 1,078 Bbls/d and NGLs three Bbls/d for a total of 1,167 BOE/d.

True initially acquired its interest in the Kerrobert area through a 2001 property acquisition, and then subsequently re-activated two McLaren formation wells, including one horizontal well. In 2002 and 2003, the Corporation drilled six successful 100% horizontal heavy oil wells, 20 Viking light oil wells, and re-completed two 100% light oil wells. During 2004, True drilled one (1.0 net) light oil well, six (6.0 net) McLaren heavy oil wells, and one (1.0 net) natural gas well in the Kerrobert area. The heavy oil wells were placed on production in 2004. True currently plans to place the light oil well on production in 2005. The gas well is suspended. The Corporation believes further development of the McLaren channel could include the drilling of an additional four to eight horizontal and four to six vertical wells. Longer term, the McLaren channel wells are candidates for steam assisted gravity drainage ("SAGD") enhanced recovery technology, which could significantly increase the overall recovery of the heavy oil from current levels. In the Viking formation, the Corporation has identified up to 30 additional drillable locations.

Dodsland, Saskatchewan

The Dodsland area is located approximately 30 kilometers north of Kindersley, Saskatchewan. The property consists of 91,852 gross (87,112 net) undeveloped and 50,143 gross (36,909 net) developed acres.

In 2001, an operated 68.8% working interest in the Dodsland Viking Gas Unit was purchased along with a large block of undeveloped land. In 2002, True increased its holdings in the Unit to 81.9%, and in 2003 further increased it to 89.2%. Unit facilities include an owned and operated three Mmcf/d capacity natural gas facility with compression, dehydration, sweetening and liquids extraction capabilities, handling unit and non-unit gas production from the Viking and Bakken Formations. During the third quarter of 2004, True replaced a rental compressor with an owned unit. In the fourth quarter of 2004, True built a wholly owned five Mmcf/d gas processing facility with compression, dehydration and liquids extraction capabilities to redirect restricted gas from third party facilities and provide capacity for additional production. In 2005, the Corporation intends to construct an additional five Mmcf/d gas processing facility with compression and dehydration capabilities.

The Dodsland property produces primarily natural gas, making up 19% of the Corporation total, and some field condensate. During 2004, sales of natural gas averaged 5,506 Mcf/d complimented by 57 Bbls/d of light crude. With total production rates from the area of 975 BOE/d, Dodsland contributed the second largest volumes for True's account.

The Corporation has 28 (25.5 net) producing natural gas wells and five (4.3 net) shut-in natural gas wells in the Dodsland Viking Gas Unit and Non-Unit. During 2004, the Corporation drilled 36 (35.4 net) natural gas wells, of which 20 were placed on production in 2004. To date in 2005 an additional four gas wells have been placed on production, and 12 wells remain to be tied-in. True has conducted extensive delineation of the pool based on single section spacing. During the fourth quarter of 2004, True began drilling downspacing locations. True anticipates drilling up to 28 downspacing locations in 2005. Up to 50 downspacing locations are identified on current lands held.

Smiley, Saskatchewan

The Smiley property, located about 35 kilometers northwest of Kindersley, Saskatchewan, produces natural gas, light and heavy oil. The property consists of 11,896 gross (9,393 net) acres of developed land and 13,258 gross (10,603 net) acres of undeveloped land. Targeted formations in the Smiley area include the Viking, Colony, Waseca, Detrital and Bakken zones at depths of 700 to 900 meters.

Natural gas production began at Smiley in 1998. In 2000, 2001, 2002 and 2003 additional wells were drilled and tied in. During 2004, True drilled and placed on production three (3.0 net) natural gas wells and six (4.1 net) heavy oil wells. A total of nine Smiley heavy oil wells are anticipated to be drilling in 2005.

In 2001, the Corporation constructed a natural gas compression, dehydration and sweetening facility, capable of four Mmcf/d. Late in 2003, the capacity was upgraded to handle approximately six Mmcf/d. True's working interest in the facility was 45.72% at the end of 2003, increasing to 82.17% effective January 1, 2004 through an asset purchase that closed on March 1, 2004. Effective April 1, 2004, True increased its working interest to 89.09%. With the January 1, 2004 acquisition, True also acquired a 25% working interest in the Loverna oil and gas facility, which has oil processing, water disposal, compression, dehydration and liquids extraction capabilities. In 2005, True is planning to build an oil facility capable of processing 2,000 Bbls/d of crude oil.

During 2004, production averaged 3,489 Mcf/d of natural gas, 253 Bbls/d of heavy oil and 12 Bbls/d of light crude oil, totalling 846 BOE/d. The Corporation has 25(16.7 net) producing crude oil wells, seven (3.8 net) shut-in oil wells, 14 (10.8 net) producing and three (1.9 net) shut-in natural gas wells in the area.

Coleville Driver, Saskatchewan

The Coleville Driver area, located 25 kilometers north-west of Kindersley, Saskatchewan produces primarily natural gas from shallow 700 to 825 meter Bakken and Mannville zones. Sales in 2004 averaged 5,384 Mcf/d of natural gas and 22 Bbls/d of heavy oil, or 919 BOE/d. The Corporation has 15 (14.1 net) producing natural gas wells, 11 (9.8 net) shut-in natural gas wells, two (1.5 net) producing crude oil wells and two (2.0 net) shut-in crude oil wells in this area. The property consists of 21,965 gross (17,734 net) acres of undeveloped land, and 16,881 gross (14,708 net) acres of developed land.

Coleville Driver facilities include a wholly owned and operated natural gas compressor station with dehydration and sweetening capabilities. True increased its working interest in this facility from 79.68% to 100% through an asset acquisition that was negotiated by True in 2003 and closed in the first quarter of 2004. In 2004, True added an additional compressor and extra dehydration to the Coleville Driver facility, increasing capacity from 5 Mmcf/d to 9.5 Mmcf/d.

True acquired its working interests in the Coleville Driver area through a combination of acquisitions, farmins, and drilling operations. During 2004, the Corporation drilled nine (9.0 net) natural gas wells and one(1.0) dry hole. With additional lands purchased and seismic being shot during 2004, the area remains an active exploitation and exploration area for the Corporation. To date in 2005, True has drilled two natural gas wells and anticipates drilling three additional gas wells this year.

Coleville South, Saskatchewan

The Coleville South area, located 18 kilometers north of Kindersley, Saskatchewan produces primarily 11 degree API heavy crude oil from the Bakken formation. The property consists of 1,725 gross (560 net) acres of developed and 5,940 gross (2,887 net) acres of undeveloped land. The Corporation has 13 (6.5 net) producing crude oil wells, one (0.5 net) Detrital gas well, one (0.5 net) water disposal well, and 16 (8.5 net) shut-in crude oil wells. During 2004, sales averaged 827 Mcf/d of natural gas and 126 Bbls/d of heavy oil, totalling 264 BOE/d.

In 2001 and 2002, True further evaluated and delineated the pool, through drilling the heavy oil wells. The Detrital natural gas well was drilled during 2003. During 2004, True has drilled and placed on production three (1.5) Bakken heavy oil wells.

Each well at Coleville South is equipped with a screw pump and heated treating and storage tanks. Late in 2003, a natural gas compression, dehydration and sweetening facility with a throughput capacity of 2.5 Mmcf/d was installed, thus allowing the tie in of the Detrital gas well and the solution gas from the oil wells. True has a 50% interest in the facility.

Based on three-dimensional seismic, ultimate full development of the project could include 50 to 60 wells, of which approximately 12 would be re-completed as water injector wells, complimented by central treating and water handling facilities and the implementation of a waterflood.

West Central Alberta

A second core area was established mid 2002 with the acquisition of Gresham Resources Inc. ("Gresham"), bringing non-operated natural gas producing properties at Rosevear and Doris. During 2003, True expanded the Corporation's Alberta land position with crown land sales, a land acquisition and a farm-in. Under the multiple phases of the farm-in agreement, the Corporation drilled a total of eight wells and recompleted one well by the end of 2004, the end of the agreement. True is committed under carried over obligations under this agreement to drill an additional two wells in 2005, one of which has been drilled to date. In 2004 and 2005, True has committed to drill an additional seven wells under various farm-in agreements, of which one has been drilled to date. By the end of 2004, True had accumulated a total of 31,234 net developed and 153,660 net undeveloped acres within Alberta.

In 2004, True produced an average of 803 BOE/d from Alberta, weighted 94% towards natural gas. During the first two months of 2005, the Corporation's Alberta production, based on field estimates, has averaged approximately 1,000 BOE/d, weighted 97% towards natural gas. In 2004, True drilled a total of 23 (11.9 net) wells in Alberta with a 61% net success rate.

<u>Edson, Alberta</u>

The Rosevear property, contained within the Edson area, is located approximately fifteen kilometers east of Edson, Alberta. With up to 14 different zones contributing to production, the main producing horizon is liquids-rich Viking at a depth of approximately 2,000 meters. The Rosevear property contains 14,080 gross (5,562 net) acres of developed land and 5,120 gross (1,861 net) acres of undeveloped land.

After acquiring its initial interest in Rosevear through the acquisition of Gresham, the Corporation drilled three natural gas wells and re-completed three wells in 2002 and 2003. During 2004, True drilled one (0.18 net) natural gas well, expected to be on-stream early in 2005. True currently has firm processing commitments for 2.4 Mmcf/d at the Suncor Rosevear plant that derive from the Gresham acquisition, expiring at the end of 2005.

The Corporation has 22 (7.9 net) producing natural gas wells at Rosevear. During 2004, sales at Rosevear averaged 1,310 Mcf/d of natural gas, 23 Bbls/d of light and medium crude and 25 Bbls/d of NGL's totalling 266 BOE/d. Also in the Edson area, True drilled one (0.02 net) gas well in 2004 at Brazeau, which is not expected to be placed on production.

<u>Doris, Alberta</u>

The Doris area is located approximately 160 kilometers north-west of Edmonton, Alberta and produces natural gas primarily from Lower Mannville sands at 1,400 meters. True entered into the Doris area via the Gresham acquisition. The area consists of 107,040 gross (63,985 net) undeveloped acres and 23,680 gross (10,495 net) developed acres. True has a 16.68% working interest in Doris I and II gas processing plants, which have compression, dehydration, sweetening and liquids extraction capabilities. All volumes are currently routed through the Doris I facility.

During 2004, the Doris area produced 2,238 Mcf/d of natural gas and one Bbl/d of NGLs totalling 374 BOE/d. The Doris property has 25 (11.0 net) natural gas wells, two (0.9 net) shut-in oil wells, and two (0.7 net) shut-in natural gas wells. Within the greater Doris area, True has operations at Parker, Mitsue and Roche. In 2004, True drilled two (2.0 net) unsuccessful wells at Parker and one (1.0 net) dry hole at Mitsue. In the Roche area, located between Parker and Doris proper, True participated in one (0.3 net) gas well and two (0.66 net) dry holes during 2004. The gas well was completed, but True does not anticipate any immediate revenue from this well. During the first quarter of 2004, three (1.6 net) natural gas wells obtained in the Gresham acquisition were placed on production, of which two (1.2 net) are still producing. True anticipates drilling up to four wells at Roche during the first half of 2005.

Whitecourt, Alberta

True gained a position within the Whitecourt area of Alberta through a combination of farmins, land sales, and small acquisitions. In 2003, True participated in one (0.25 net) natural gas well at Goodwin. Two zones in the well were tied in by early 2004. In 2004 True drilled 13 (6.2 net) wells at Goodwin, Whitecourt, Corbett, Thunder and Two Creek, at a 90% net success rate. By the end of 2004, six wells were on production and four are expected to be placed on production in 2005.

During 2004, Whitecourt properties produced an average of 608 Mcf/d of natural gas and 3 Bbls/d of NGLs, totalling 104 BOE/d. The Corporation has 5,920 gross (2,397 net) developed acres and 14,560 gross (9,258 net) undeveloped acres of land in the Whitecourt area.

Other Alberta Minor Properties

At Donalda, located 130 kilometers south east of Edmonton, Alberta, True has three (2.4 net) producing gas wells, one drilled in 2003 and one acquired with the Gresham acquisition. True has 2,600 gross (2,600 net) developed acres and 2,317 gross (2,157 net) undeveloped acres at Donalda. In 2004, True produced an average of 231 Mcf/d at Donalda, or 39 BOE/d. During 2004, average production from the other Alberta minor properties, excluding Donalda, averaged an aggregate of 118 Mcf/d of natural gas, or 20 BOE/d.

During 2004, True drilled one (0.50 net) gas well at Ferrier and one (1.0 net) gas well at Lochend, neither of which are currently on production. The Corporation has 13,617 gross (7,665 net) undeveloped acres and 960 gross (648 net) developed acres of land at Lochend.

Oil And Gas Wells

The following table sets forth the number and status of wells in which the Corporation has a working interest as at December 31, 2004.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	-	-	2.0	.88	63.0	25.98	14.0	6.56
Saskatchewan	671.0	91.24	32.0	19.17	112.0	68.96	48.0	36.29
Total	671.0	91.24	34.0	20.05	175.0	94.94	62.0	42.85

Properties with no Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2004.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	69,967	31,234	252,188	153,660	322,155	184,894
Saskatchewan	106,459	73,051	197,268	152,864	303,727	225,915
Total	176,426	104,285	449,456	306,524	625,882	410,809

As at December 31, 2004, True has committed to drill four wells in Alberta by the end of 2005 pursuant to various farm-in agreements with oil and gas companies at an estimated cost of $1.4 million. Subsequent to year end 2004, True has further committed to drill an additional five wells at a total estimated cost of $4.5 million to True.

True expects that rights to explore, develop and exploit approximately 35,000 net acres of its undeveloped land holdings will expire by December 31, 2005.

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation has included the estimated future well abandonment costs for existing and future reserves wells in the economic forecasts. The Corporation uses its historical cost information on an area by area basis as the means for estimating the future abandonment and reclamation costs. When this information is not available, the estimate is determined with reference to appropriate regulatory standards and requirements. Additional abandonment and reclamation costs associated with non-reserves wells, reclamation costs for wells with reserves and facility abandonment and reclamation expenses have not been included in the reserve report analysis.

In the GLJ Report, the number of net oil and gas wells for which revenues and costs, including future well abandonment costs, varies by year depending on when wells commence and end production. The total amount of such costs that True expects to incur, all of which is deducted in the total proved forecast price and cost reserve report, before estimated salvage value, is $5,647,000 ($2,497,000 discounted at 10%). In the constant prices and costs total proved reserve report, the total of such costs, fully deducted, is $4,684,000 ($2,170,000 discounted at 10%). In the next three financial years, these costs are as follows:

Forecast Prices and Costs (Total Proved)

Year	Oil Wells	Gas Wells	Abandonment Costs ($000's)
2005	14	-	361
2006	1	8	192
2007	5	5	226
Subtotal	20	13	779
Remainder	73	119	4,868
Total	93	132	5,647
Total, discounted at 10%			2,497

Constant Prices and Costs (Total Proved)

Year	Oil Wells	Gas Wells	Abandonment Costs ($000's)
2005	16	-	391
2006	3	8	237
2007	4	5	199
Subtotal	23	13	827
Remainder	70	119	3,857
Total	93	132	4,684
Total, discounted at 10%			2,170

At December 31, 2004, the estimated total undiscounted amount required to settle the asset retirement obligations (being abandonment and reclamation costs for net producing and shut-in wells and facilities) of the Corporation is approximately $7.2 million, of which $3.95 million has been recorded in various fiscal periods (net cost of $3.25 million). The incremental costs for future site restoration for surface leases and pipelines, reduced by the estimated salvage values for all including wells, is estimated by True to be nominal.

Included in the GLJ Report (constant prices and costs) for 2005 are 177 net producing wells, the same number of net producing wells utilized in determining the total future site restoration costs for net producing and shut-in wells above.

Tax Horizon

True was not required to pay income taxes for its most recently completed financial year. In the economic forecasts prepared by GLJ, income taxes are payable by the Corporation in 2005. Currently, the Corporation expects income taxes may be payable by the Corporation in 2005, based on current anticipated capital expenditures and cash flows for 2005.

Capital Expenditures Incurred

The following tables summarize capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to the Corporation's activities for the year ended December 31, 2004:

Property acquisition costs	
Proved properties	$ 8,395,012
Undeveloped properties	5,789,363
Exploration costs	8,734,483
Development costs	32,290,588
Dispositions	(290,517)
Total	$ 54,918,929

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended December 31, 2004:

	Exploration		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Light and Medium Oil	1	1.0	1	1.0	2	2.0
Natural Gas	7	5.5	57	49.5	64	55.0
Heavy Oil	-	-	15	11.6	15	11.6
Dry	8	5.3	-	-	8	5.3
Total	16	11.8	73	62.1	89	73.9

In 2005, True anticipates drilling approximately 90 wells, with approximately 20 wells in Alberta and the remainder in Saskatchewan. Capital spending in 2005 will be dependent upon the outcome of the currently outstanding Offer to purchase Meridian. If the Offer is successful, True's capital program will be re-evaluated in light of the drilling opportunities on the Meridian lands. Please also see "Principal Oil and Gas Properties".

Production Estimates

The following table sets out the volumes of the Corporation's working interest production estimated for the year ended December 31, 2005, which is reflected in the estimate of future net revenue disclosed in the Forecast Price tables contained under "Disclosure of Reserves Data".

	Light and Medium Oil *(Bbls/d)*	Heavy Oil *(Bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbls/d)*	BOE *(BOE/d)*
Total proved	168	1,856	26,165	123	6,507
Total proved plus probable	170	2,017	29,487	130	7,231

There are no fields that will account for more than 20% of total estimated daily production of the Corporation for 2005 in either total proved and total proved and probable reserves, as grouped in the GLJ Report.

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated.

	Quarter Ended			
	2004			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production[(1)]				
Light and Medium Crude Oil (Bbls/d)	161	222	163	186
Heavy Oil (Bbls/d)	1,869	1,473	1,382	1,323
Gas (Mcf/d)	23,174	20,543	20,285	15,648
NGLs (Bbls/d)	34	11	45	38
Combined (BOE/d)	5,927	5,130	4,972	4,155
Average Price Received (before transportation)				
Light and Medium Crude Oil ($/Bbl)	57.91	50.46	48.07	45.04
Heavy Oil ($/Bbls)	24.47	35.62	27.82	25.94
Gas ($/Mcf)	6.68	6.29	7.06	6.56
NGLs ($/Bbls)	48.07	23.90	33.87	32.73
Combined ($/BOE)	35.71	37.63	38.41	35.28
Royalties Paid				
Light and Medium Crude Oil ($/Bbls)	7.01	6.16	10.44	7.29
Heavy Oil ($/Bbls)	5.26	8.94	5.17	5.17
Gas ($/Mcf)	1.88	1.71	1.99	1.74
NGLs ($/Bbls)	6.27	7.28	8.84	5.35
Combined ($/BOE)	9.25	9.71	9.99	8.58
Operating Expenses ($/BOE)				
Light and Medium Crude Oil ($/Bbls)	12.45	8.39	9.10	12.08
Heavy Oil ($/Bbls)	5.51	6.64	6.01	4.80
Gas ($/Mcf)	.76	1.11	.87	1.16
NGLs ($/Bbls)	8.03	14.30	.36	8.38
Combined ($/BOE)	5.10	6.74	5.54	6.53
Netback Received ($/BOE)[(2)] (after transportation)				
Light and Medium Crude Oil ($/Bbls)	38.25	35.87	28.84	25.26
Heavy Oil ($/Bbls)	12.63	18.92	15.31	15.24
Gas ($/Mcf)	3.88	3.27	4.04	3.51
NGLs ($/Bbls)	33.78	2.32	24.67	19.00
Combined ($/BOE)	20.37	20.10	21.88	19.34

Notes:

(1) Before deduction of royalties.
(2) Netbacks are calculated by subtracting royalties and operating costs from revenues.

35

The following table indicates the Corporation's average daily production (including production from its major areas) for the year ended December 31, 2004.

	Light and Medium Crude Oil (Bbls/d)	Heavy Oil (Bbls/d)	Gas (Mcf/d)	NGLs (Bbls/d)	BOE (BOE/d)
Rosevear	23	-	1,310	25	266
Doris	-	-	2,238	1	374
Donalda	-	-	231	-	39
Whitecourt	-	-	608	3	104
Minor Properties	-	-	118	-	20
Total Alberta	23	-	4,505	29	803
Kerrobert McLaren	-	1,078	-	-	1,078
Kerrobert/Dodsland	86	-	642	3	196
Dodsland	57	-	4,864	-	868
Smiley	12	253	3,489	-	846
Coleville Driver	-	22	5,384	-	919
Coleville South	-	126	827	-	264
Minor Properties	5	34	212	-	74
Total Saskatchewan	160	1,513	15,418	3	4,245
Total	183	1,513	19,923	32	5,048

True's production for the year ended December 31, 2004 was 3.6% light quality crude oil (32° API or greater), 30.0% heavy oil (17° API or less), 0.6% natural gas liquids and 65.8% natural gas.

For the twelve months ended December 31, 2004, approximately 28.6% of True's gross revenue, before transportation charges, was derived from crude oil and natural gas liquids production and 71.4% was derived from natural gas production.

Marketing and Forward Contracts

The Corporation's natural gas marketing strategy is to sell natural gas production in the spot market, complemented by hedging contracts and instruments. On occasion, True has historically entered into various natural gas commodity price swaps. As at December 31, 2004, the Corporation did not have any natural gas commodity price swaps in place.

During 2004 the Corporation did not enter into any natural gas commodity price swaps or fixed price sales contracts.

True, on occasion has entered into short-term contracts to sell its crude oil production with third parties who have demonstrated their ability to market crude oil effectively. These contracts are complemented by fixed price purchase contracts similar to the Corporation's natural gas marketing strategy. No material commitments to sell natural gas and crude oil were outstanding at December 31, 2004.

APPENDIX A
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of True Energy Inc. (the "Company") is 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 consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2004 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2004 using constant prices and costs; and

(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserve 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 Reserve 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 Reserve Committee, approved

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of 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.

(signed) *"Paul R. Baay"*
Paul R. Baay
President and Chief Executive Officer

(signed) *"Joan E. Dunne"*
Joan E. Dunne
Vice President, Finance and Chief Financial Officer

(signed) *"W.C. (Mickey) Dunn"*
W. C. (Mickey) Dunn
Director and Chairman of the Board of Directors

(signed) *"James R. Glass"*
James R. Glass
Director and Chairman of the Reserves Committee

March 3, 2005

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

To the board of directors of True Energy Inc. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2004. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2004, using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas reserves estimated as at December 31, 2004, using constant prices and costs; and

   (ii) the related estimated future net revenue.

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 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, 2004, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
		Audited	Evaluated	Reviewed	Total
January 21, 2005	Canada	$0	$171,227 M	$0	$171,227M

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.

6. We have no responsibility to update this evaluation for events and circumstances occurring after the preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Gilbert Laustsen Jung Associates Ltd., Calgary, Alberta Canada — Dated March 3, 2005

(signed) "*Neil I. Dell, P. Eng.*"
Vice-President