



**FORM 51-101F1
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS
INFORMATION**

For the year ended December 31, 2015

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DEFINITIONS

In this Statement of Reserves Data and Other Oil and Gas Information, the following terms shall have the meanings set forth below, unless otherwise indicated. Certain terms are defined in National Instrument 51-101 (“NI 51-101”) and the Canadian Securities Administrators (“CSA”) Staff Notice 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA Staff Notice 51-324.

“**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.

“**Corporation**” means Harvest Operations Corp.

“**Contingent Resources**” are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies.

“**Credit Facility**” means the \$1.0 billion revolving credit facility, as amended, provided by a syndicate of lenders to Harvest as more fully described in the “*General Description of Capital Structure*” section in the Annual Information Form for the year ended December 31, 2015.

“**Deep Basin Partnership**” or “**DBP**” means Harvest’s upstream joint venture with KERR Canada Co. Ltd. (“KERR”) formed on April 23, 2014. As at December 31, 2015, Harvest owned 595,581,234 of common partnership units in Deep Basin Partnership representing an approximately 81.71% equity interest.

“**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 include 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, complete 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 process 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 and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

“**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 (sometime 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 crew and others conducting those studies (collectively sometimes referred to as “geological and geophysical costs”);
- b) costs of carrying and retaining unproved properties, such as lease 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 developmental well, a service well or a stratigraphic test well.

“Equity Investment” means Harvest’s equity interest in the Deep Basin Partnership.

“Farmout” means an agreement whereby a third party agrees to pay for all or a portion of the drilling of a well on one or more of the properties in order to earn an interest therein, with an Operating Subsidiary retaining a residual interest in such properties.

“Forecast Prices and Costs” means future prices and costs that are:

- a) generally accepted as being a reasonable outlook on the future,
- b) if, and only to the extent that, 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 or costs referred to in paragraph (a) are used.

“GAAP” means Generally Accepted Accounting Principles.

“GLJ” means GLJ Petroleum Consultants Ltd., independent oil and natural gas reserves evaluators of Calgary, Alberta.

“gross” means:

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

“Harvest” means Harvest Operations Corp.

“Independent Qualified Reserves Evaluator” means GLJ, who evaluated the crude oil, natural gas liquids and natural gas reserves of Harvest as at December 31, 2015 in accordance with the standards contained in the COGE Handbook and the reserve definitions and other requirements contained in NI 51-101.

“KNOC” means Korea National Oil Corporation.

“net” means:

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

“Operating Subsidiaries” means Breeze Resource Partnership, Breeze Trust No. 1, Breeze Trust No. 2, and Hay River Partnership, each a direct or indirect wholly-owned subsidiary of the Corporation, and “Operating Subsidiary” means any one of them.

“Reserves” are the 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

- a) analysis of drilling, geological, geophysical and engineering data;

- b) the use of established technology; and
- c) specified economic conditions.

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.
- c) **Possible Reserves** are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

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

- a) **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 (e.g. 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:

Developed Producing Reserves are those reserves that are expected to be recovered from completion intervals open to the wellbore 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.

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.

- b) **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 classification (proved, probable, possible) 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 reserve evaluator'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.

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.

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

“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.

“Stratigraphic test well” means a drilling effort, geologically directed, 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”.

“Working Interest” means an undivided interest held by a party in an oil and/or natural gas or oil sands or mineral lease granted by a Crown or freehold mineral owner, which interest gives the holder the right to "work" the property (lease) to explore for, develop, produce and market the lease substances but does not include, among other things, a royalty, overriding royalty, gross overriding royalty, net profits interest or other interest that entitles the holder thereof to a share of production or proceeds of sale of production without a corresponding right or obligation to "work" the property.

ABBREVIATIONS AND CONVERSIONS

In this document, the following abbreviations have the meanings set forth below:

/d	Per day
3-D	Three dimensional
AECO	AECO “C” hub price index for Alberta natural gas
°API	The measure of the density or gravity of liquid petroleum products
boe ⁽¹⁾	Barrel of oil equivalent on the conversion factor of 6 mcf of natural gas to one bbl of oil
bbl	Barrel
bbls	Barrels
Bcf	Billion cubic feet
DBP	Deep Basin Partnership
EOR	Enhanced oil recovery
GJ	Gigajoule
H ₂ S	Hydrogen sulfide gas
Mcf	Thousand cubic feet
MMbbls	Million barrels
MMboe	Million barrels of oil equivalent
MMbtu	Million of British thermal units
MMcf	Million cubic feet
NGLs	Natural gas liquids
SAGD	Steam-assisted gravity drainage is an enhanced oil recovery technology for producing heavy crude oil and bitumen
WTI	West Texas Intermediate, the reference price in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
\$ millions	Millions of dollars

(1) 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.

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units):

To Convert From	To	Multiply By
mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

ADVISORY

This Statement contains non-GAAP measures and forward-looking information about our current expectations, estimates and projections. Readers are cautioned that this Statement should be read in conjunction with the “Non-GAAP Measures” and “Special Note Regarding Forward-Looking Information” sections at the end of this Statement.

All dollar amounts set forth in this statement are in Canadian dollars, except where otherwise noted.

DATE OF STATEMENT

This Statement of Reserves Data and Other Oil and Gas Information (the “Statement”) of Harvest is dated February 12, 2016, Harvest’s Equity Investment is dated February 12, 2016, and Harvest’s BlackGold property is dated February 17, 2016. The effective date of the reserves and future net revenue information provided is December 31, 2015, unless otherwise indicated. The information contained herein was prepared on March 29, 2016.

DISCLOSURE OF RESERVES DATA

Harvest retained an Independent Qualified Reserves Evaluator to evaluate and prepare reports on 100% of Harvest’s Reserves as of December 31, 2015. Harvest’s Reserves were evaluated by GLJ. Possible Reserves were not evaluated, with the exception of the BlackGold oil sands project where GLJ evaluated Possible Reserves and Contingent Resources.

Harvest’s investment in Deep Basin Partnership (“DBP”) is accounted for using the equity method of accounting and pursuant to NI 51-101, Harvest is required to separately disclose information concerning DBP’s oil and gas reserves, future net revenue and costs incurred based on Harvest’s equity interest in DBP. Accordingly, in certain tables that follow, information is first provided in respect of Harvest and its Operating Subsidiaries, which are consolidated for financial reporting purposes (under the heading “Consolidated Entities”) and then in respect of DBP (under the heading “Equity Investment”). GLJ evaluated 100% of DBP’s natural gas and NGLs reserves as at December 31, 2015. All information with respect to DBP reflects Harvest’s 81.71% equity interest in DBP as at December 31, 2015, except for per unit information.

Readers are cautioned that Harvest does not have any direct interest in, or right to, the reserves or future net revenue of DBP disclosed herein nor does Harvest have any direct obligations in respect of, or liability for, the costs incurred by DBP.

The reserves data and associated tables contained in this report summarize the reserves of crude oil, natural gas liquids and natural gas and the net present values of future net revenues associated with the reserves of Harvest’s Consolidated Entities and Equity Investment as evaluated in the report prepared by GLJ (the “Reserves Reports”), based on forecast price assumptions presented in accordance with the standards contained in the COGE Handbook and the reserves definitions and other requirements contained in NI 51-101.

The tables presented herein summarize the data contained in the Reserves Reports and as a result may contain slight rounding differences although they are substantively the same as the data in the Reserves Reports. Totals may not add due to rounding.

All Reserves are located in Canada and, in the provinces of Alberta, British Columbia and Saskatchewan.

The future net revenue numbers presented throughout this Statement, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value of the Reserves. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein. There is no assurance that the forecast price and cost assumptions will be attained and variances could be material.

Reserves Data (Forecast Prices and Costs)

The following tables detail the aggregate gross and net Reserves of Harvest's Consolidated Entities and Equity Investment, at December 31, 2015, using forecast prices and costs as well as the aggregate net present value ("NPV") of future net revenue attributable to the reserves estimated using forecast prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%.

Summary of Oil & Gas Reserves															
As of December 31, 2015															
Forecast Prices and Costs															
Consolidated Entities	Light and		Heavy Oil		Bitumen		Conventional		Shale		Natural Gas		Total Oil		
	Medium Oil		(MMbbls)		(MMbbls)		(MMbbls)		Natural Gas		Natural Gas		Liquids		Equivalent
Reserves Category	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	
Consolidated Entities															
Proved															
Developed Producing	25.4	23.2	12.8	11.8	—	—	167.3	154.0	—	—	6.6	4.8	72.7	65.5	
Developed Non-Producing	2.2	2.0	0.8	0.7	—	—	7.1	6.2	—	—	0.3	0.2	4.5	4.0	
Undeveloped	5.7	4.7	0.5	0.5	96.0	86.6	75.3	68.6	5.4	5.1	4.6	3.8	120.3	107.9	
Total Proved	33.3	30.0	14.1	13.0	96.0	86.6	249.7	228.8	5.4	5.1	11.5	8.8	197.5	177.4	
Probable	19.4	17.0	5.4	4.8	163.2	127.9	161.0	145.3	2.5	2.3	8.0	5.9	223.2	180.2	
Total Proved + Probable	52.7	46.9	19.6	17.8	259.3	214.5	410.6	374.1	7.9	7.4	19.5	14.7	420.8	357.6	
Equity Investment															
Reserves Category															
Proved															
Developed Producing	—	—	—	—	—	—	25.2	22.4	7.1	6.6	1.9	1.4	7.3	6.3	
Developed Non-Producing	—	—	—	—	—	—	—	—	—	—	—	—	—	—	
Undeveloped	—	—	—	—	—	—	—	—	32.0	30.1	4.2	3.4	9.5	8.4	
Total Proved	—	—	—	—	—	—	25.2	22.4	39.1	36.8	6.1	4.8	16.8	14.7	
Probable	—	—	—	—	—	—	29.3	26.8	36.1	33.5	5.4	4.1	16.3	14.1	
Total Proved + Probable	—	—	—	—	—	—	54.5	49.3	75.2	70.3	11.5	8.9	33.1	28.8	
Total⁽¹⁾															
Reserves Category															
Proved															
Developed Producing	25.4	23.2	12.8	11.8	—	—	192.4	176.4	7.1	6.6	8.6	6.2	80.0	71.8	
Developed Non-Producing	2.2	2.0	0.8	0.7	—	—	7.1	6.2	—	—	0.3	0.2	4.5	4.0	
Undeveloped	5.7	4.7	0.5	0.5	96.0	86.6	75.3	68.6	37.4	35.3	8.7	7.2	129.8	116.3	
Total Proved	33.3	30.0	14.1	13.0	96.0	86.6	274.8	251.3	44.5	41.9	17.6	13.7	214.3	192.1	
Probable	19.4	17.0	5.4	4.8	163.2	127.9	190.3	172.2	38.6	35.8	13.4	10.0	239.5	194.3	
Total Proved + Probable	52.7	46.9	19.6	17.8	259.3	214.5	465.2	423.4	83.1	77.7	31.0	23.6	453.9	386.4	

(1) Total Consolidated Entities plus Total Equity Investment

**Summary of Net Present Values of Future Net Revenue
As of December 31, 2015
Forecast Prices and Costs**

Consolidated Entities Reserves Category	Before Income Taxes Discounted at %/year (\$ millions)					NPV 10%/boe (\$/boe) ⁽¹⁾
	0%	5%	10%	15%	20%	
Proved						
Developed Producing	807	902	795	687	600	12.13
Developed Non-Producing	121	76	54	41	32	13.46
Undeveloped	2,121	1,052	570	321	179	5.28
Total Proved	3,049	2,030	1,418	1,048	811	7.99
Probable	5,415	2,359	1,180	649	380	6.55
Total Proved + Probable	8,463	4,389	2,598	1,697	1,191	7.26
Equity Investment						
Reserves Category						
Proved						
Developed Producing	106	84	70	60	53	11.07
Developed Non-Producing	0	0	0	0	0	0.00
Undeveloped	96	40	13	0	(7)	1.59
Total Proved	202	124	83	60	46	5.65
Probable	296	155	91	57	37	6.41
Total Proved + Probable	499	279	174	117	83	6.02
Total⁽²⁾						
Reserves Category						
Proved						
Developed Producing	913	985	864	747	652	12.04
Developed Non-Producing	121	76	54	41	32	13.46
Undeveloped	2,217	1,092	583	321	172	5.01
Total Proved	3,251	2,154	1,501	1,108	857	7.81
Probable	5,711	2,514	1,270	705	417	6.54
Total Proved + Probable	8,962	4,668	2,771	1,814	1,274	7.17

(1) Unit values are based upon net reserves volumes.

(2) Total Consolidated Entities plus Total Equity Investment

**Summary of Net Present Values of Future Net Revenue
As of December 31, 2015
Forecast Prices and Costs**

Consolidated Entities	After Income Taxes Discounted at (%/year) (\$ millions)				
Reserves Category	0%	5%	10%	15%	20%
Consolidated Entities					
Proved					
Developed Producing	807	902	795	687	600
Developed Non-Producing	121	76	54	41	32
Undeveloped	1,849	955	531	304	171
Total Proved	2,777	1,932	1,379	1,032	803
Probable	4,286	1,894	961	535	316
Total Proved + Probable	7,063	3,826	2,340	1,566	1,119
Equity Investment					
Reserves Category					
Proved					
Developed Producing	97	78	66	57	51
Developed Non-Producing	0	0	0	0	0
Undeveloped	69	24	3	(8)	(13)
Total Proved	167	103	69	49	38
Probable	216	110	61	36	21
Total Proved + Probable	382	212	130	85	59
Total⁽¹⁾					
Reserves Category					
Proved					
Developed Producing	904	980	860	744	650
Developed Non-Producing	121	76	54	41	32
Undeveloped	1,919	979	534	296	158
Total Proved	2,944	2,035	1,448	1,081	841
Probable	4,502	2,004	1,022	570	337
Total Proved + Probable	7,445	4,039	2,469	1,651	1,178

(1) Total Consolidated Entities plus Total Equity Investment

The following tables provide (i) a breakdown of various elements of undiscounted future net revenue attributable to proved reserves and proved plus probable reserves of Harvest's Consolidated Entities and Equity Investment, and (ii) the future net revenue by production group in each reserves category:

Total Future Net Revenue (undiscounted)
As of December 31, 2015
Forecast Prices and Costs (\$ millions)

Consolidated Entities								
Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved	11,803	1,236	5,222	1,606	691	3,049	271	2,777
Proved + Probable	27,827	4,439	9,693	4,417	815	8,463	1,400	7,063
Equity Investment								
Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved	757	124	218	205	8	202	36	167
Proved + Probable	1,561	278	439	333	12	499	116	382
Total⁽¹⁾								
Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved	12,560	1,359	5,440	1,811	700	3,251	307	2,944
Proved + Probable	29,389	4,717	10,132	4,750	827	8,962	1,516	7,445

(1) Total Consolidated Entities plus Total Equity Investment

Future Net Revenue by Production Group
As of December 31, 2015
Forecast Prices and Costs

Consolidated Entities			
Reserves Category	Production Group	Before Income Taxes (discounted at 10%/year) (\$ millions)	Unit Value ⁽³⁾
Proved Reserves	Conventional Reserves		
	Light and Medium Crude Oil ⁽¹⁾	445	\$14.75/bbl
	Heavy Crude Oil ⁽¹⁾	173	\$11.87/bbl
	Conventional Natural Gas ⁽²⁾	311	\$1.17/mcf
	Non-Conventional Reserves		
	Bitumen	477	\$5.51/bbl
	Shale Gas	12	\$1.28/mcf
	Total	1,418	\$7.99/boe
Proved + Probable Reserves	Conventional Reserves		
	Light and Medium Crude Oil ⁽¹⁾	694	\$14.73/bbl
	Heavy Crude Oil ⁽¹⁾	242	\$11.95/bbl
	Conventional Natural Gas ⁽²⁾	487	\$1.10/mcf
	Non-Conventional Reserves		
	Bitumen	1,154	\$5.38/bbl
	Shale Gas	21	\$1.61/mcf
	Total	2,598	\$7.26/boe

Equity Investment			
Reserves Category			
Proved Reserves	Conventional Reserves		
	Conventional Natural Gas ⁽²⁾	41	\$1.49/mcf
	Non-Conventional Reserves		
	Shale Natural Gas	42	\$0.70/mcf
	Total	83	\$5.65/boe
Proved + Probable Reserves	Conventional Reserves		
	Conventional Natural Gas ⁽²⁾	60	\$1.03/mcf
	Non-Conventional Reserves		
	Shale Gas	113	\$0.99/mcf
	Total	174	\$6.02/boe
Total⁽⁴⁾			
Reserves Category			
Proved Reserves	Conventional Reserves		
	Light and Medium Crude Oil ⁽¹⁾	445	\$14.75/bbl
	Heavy Crude Oil ⁽¹⁾	173	\$11.87/bbl
	Conventional Natural Gas ⁽²⁾	351	\$1.20/mcf
	Non-Conventional Reserves		
	Bitumen	477	\$5.51/bbl
	Shale Gas	54	\$0.80/mcf
		Total	1,501
Proved + Probable Reserves	Conventional Reserves		
	Light and Medium Crude Oil ⁽¹⁾	694	\$14.73/bbl
	Heavy Crude Oil ⁽¹⁾	242	\$11.95/bbl
	Conventional Natural Gas ⁽²⁾	547	\$1.09/mcf
	Non-Conventional Reserves		
	Bitumen	1,154	\$5.38/bbl
	Shale Gas	134	\$1.05/mcf
		Total	2,771

(1) Includes solution gas and associated by-products

(2) Includes associated by-products

(3) Unit values are based upon net reserves volumes

(4) Total Consolidated Entities plus Total Equity Investment

PRICING ASSUMPTIONS

The forecast costs and prices assume increases in wellhead selling prices, and take into account inflation with respect to future operating and capital costs. Crude Oil, NGLs and Natural Gas benchmark reference pricing, inflation and exchange rates utilized in the Reserves Report are based on the average of the Sproule, McDaniel and GLJ January 1, 2016 price forecasts, as summarized below. A complete listing of the individual forecasts used to derive the blended forecast can be found on the websites of these three Independent Qualified Reserves Evaluators:

**Summary of Pricing and Inflation Rate Assumptions – Average of GLJ, Sproule and McDaniel
As of January 1, 2016
Forecast Prices and Costs**

Year	OIL			Natural Gas		Natural Gas Liquids				Inflation Rate ⁽⁶⁾ (%/Year)	Exchange Rate ⁽⁷⁾ (US\$/Cdn\$)	
	WTI Crude Oil ⁽¹⁾ (US\$/bbl)	Edmonton Light Crude Oil ⁽²⁾ (Cdn\$/ bbl)	Alberta Heavy Crude Oil ⁽³⁾ (Cdn\$/ bbl)	Alberta Bow River Hardisty Crude (Cdn\$/ bbl)	Sask Cromer Crude Oil ⁽⁵⁾ (Cdn\$/ bbl)	Alberta AECO Spot Price (Cdn\$/ mmbtu)	Spec Ethane (Cdn\$/ bbl)	Edmonton Propane (Cdn\$/ bbl)	Edmonton Butane (Cdn\$/ bbl)			Edmonton Pentanes + (Cdn\$/ bbl)
2016	44.67	55.89	39.20	45.21	51.61	2.57	8.35	9.76	38.73	60.16	0.7	0.735
2017	55.20	66.47	48.55	55.20	61.96	3.14	10.24	15.88	46.91	70.95	1.3	0.767
2018	63.47	73.21	53.85	61.05	68.27	3.47	11.35	24.09	52.58	78.05	1.8	0.802
2019	71.00	81.35	60.36	68.23	75.91	3.80	12.41	30.49	59.42	86.58	1.8	0.817
2020	74.77	84.57	63.29	71.34	78.93	3.99	13.03	33.69	62.81	90.00	1.8	0.833
2021	78.24	87.88	66.11	74.38	82.01	4.13	13.53	34.95	65.25	93.46	1.8	0.842
2022	81.75	92.01	69.59	78.16	85.87	4.30	14.10	36.45	68.33	97.79	1.8	0.842
2023	85.37	96.24	73.02	81.92	89.81	4.48	14.73	38.06	71.46	102.23	1.8	0.842
2024	87.32	98.17	75.12	84.07	91.63	4.60	15.17	38.79	72.90	104.29	1.8	0.842
2025	88.90	99.94	76.12	85.59	93.26	4.70	15.49	39.50	74.22	106.16	1.8	0.842
Thereafter	1.8%/yr	1.8%/yr	1.8%/yr	1.8%/yr	1.8%/yr	1.8%/yr	1.8%/yr	1.8%/yr	1.8%/yr	1.8%/yr	1.8%/yr	0.842

(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API/0.5% sulphur.

(2) Edmonton Light Sweet 40 degrees API, 0.3% sulphur.

(3) Heavy crude oil 12 degrees API at Hardisty Alberta (after deduction of blending costs to reach pipeline quality).

(4) Bow River at Hardisty Alberta (Heavy stream).

(5) Midale Cromer crude oil 29 degrees API, 2.0% sulphur.

(6) Inflation rates for forecasting prices and costs.

(7) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices prior to hedging realized by Harvest's Consolidated Entities for the year ended December 31, 2015, were \$2.62/mcf for natural gas, \$29.36/bbl for natural gas liquids, \$49.59/bbl for light/medium oil, and \$42.69/bbl for heavy oil.

Weighted average historical prices prior to hedging realized by the Deep Basin Partnership for the year ended December 31, 2015, were \$2.69/mcf for natural gas and \$38.08/bbl for natural gas liquids.

RECONCILIATION OF CHANGES IN RESERVES

The following reconciliation of reserves is provided for Harvest's Consolidated Entities only:

Reconciliation													
By Principal Product Type													
Forecast Prices and Cost													
Factors	Light and Medium Oil (MMbbl)			Heavy Oil (MMbbl)			Bitumen (MMbbl)			Natural Gas Liquids (MMbbl)			
	Gross Proved	Gross Probable	Gross Proved + Probable	Gross Proved	Gross Probable	Gross Proved + Probable	Gross Proved	Gross Probable	Gross Proved + Probable	Gross Proved	Gross Probable	Gross Proved + Probable	Gross Proved + Probable
31-Dec-14	27.1	12.5	39.6	31.7	16.3	48.0	96.0	163.2	259.3	11.3	7.2	18.5	
Product Type Transfers	14.2	9.6	23.7	(14.2)	(9.6)	(23.7)	—	—	—	—	—	—	—
Adjusted 31-Dec-14	41.2	22.1	63.3	17.5	6.8	24.2	96.0	163.2	259.3	11.3	7.2	18.5	
Discoveries	0.1	—	0.1	—	—	—	—	—	—	—	—	—	—
Extensions/Improved Recovery	0.4	1.0	1.4	—	—	—	—	—	—	1.4	1.5	2.9	
Technical Revisions	(3.3)	(2.0)	(5.3)	3.9	(2.1)	1.8	—	—	—	0.7	(0.6)	0.1	
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	(1.8)	(0.6)	(2.4)	(0.4)	(0.1)	(0.5)	—	—	—	(0.2)	(0.1)	(0.2)	
Economic Factors	(0.2)	(1.1)	(1.3)	(2.8)	1.0	(1.8)	—	—	—	(0.3)	(0.1)	(0.4)	
Production ⁽¹⁾	(3.2)	—	(3.2)	(4.1)	—	(4.1)	—	—	—	(1.4)	—	(1.4)	
31-Dec-15	33.3	19.3	52.7	14.1	5.4	19.6	96.0	163.2	259.3	11.5	8.0	19.5	

Factors	Conventional Natural Gas (Bcf)			Shale Gas (Bcf)			Coal bed Methane (Bcf)			Total Oil Equivalent (MMboe)			
	Gross Proved	Gross Probable	Gross Proved + Probable	Gross Proved	Gross Probable	Gross Proved + Probable	Gross Proved	Gross Probable	Gross Proved + Probable	Gross Proved	Gross Probable	Gross Proved + Probable	Gross Proved + Probable
31-Dec-14	250.7	116.9	367.6	—	—	—	3.1	1.3	4.4	208.3	219.0	427.3	
Product Type Transfers	(4.8)	(2.3)	(7.1)	6.6	2.8	9.4	(1.8)	(0.5)	(2.3)	—	—	—	—
Adjusted 31-Dec-14	245.9	114.6	360.5	6.6	2.8	9.4	1.3	0.8	2.1	208.3	219.0	427.3	
Discoveries	—	—	—	—	—	—	—	—	—	0.1	—	0.1	
Extensions/Improved Recovery	28.7	35.3	64.0	—	—	—	—	—	—	6.6	8.4	15.0	
Technical Revisions	28.6	13.5	42.1	(1.1)	(0.3)	(1.5)	—	—	—	5.9	(2.6)	3.4	
Acquisitions	2.8	0.6	3.4	—	—	—	—	—	—	0.5	0.1	0.6	
Dispositions	(8.5)	(2.9)	(11.4)	—	—	—	(1.2)	(0.8)	(2.1)	(3.9)	(1.4)	(5.4)	
Economic Factors	(9.9)	—	(9.9)	—	—	—	—	—	—	(4.9)	(0.2)	(5.1)	
Production ⁽¹⁾	(37.9)	—	(37.9)	—	—	—	(0.1)	—	(0.1)	(15.1)	—	(15.1)	
31-Dec-15	249.6	161.0	410.6	5.4	2.5	7.9	—	—	—	197.5	223.3	420.8	

(1) The stated 2015 production of 15.1 mmboe in this table differs from the actual recorded production of 15.2 mmboe for Harvest in 2015 as the Independent Qualified Reserves Evaluator's report was prepared prior to 2015 actual production data was available.

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

Proved and Probable Undeveloped Reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. As at January 1, 2016, Harvest's Consolidated Entities have a total of 124.8 MMboe of gross Reserves that are classified as Proved Non-Producing Reserves. Of these Non-Producing Reserves, approximately 96% are Undeveloped Reserves. The balance are Developed Non-Producing Reserves which would be wells that were not producing as of December 31, 2015 and may be brought on production given economics and production information as at January 1, 2016.

Gross Reserves First Attributed by Year ⁽¹⁾														
Proved Undeveloped														
Light and Medium Crude Oil		Heavy Crude Oil		Conventional Natural Gas		Natural Gas Liquids		Shale Gas		Bitumen		Total Oil Equivalent		
(MMbbl)		(MMbbl)		(Bcf)		(MMbbl)		(Bcf)		(MMbbl)		(MMboe)		
First Attributed	Total at Year	First Attributed	Total at Year	First Attributed	Total at Year	First Attributed	Total at Year	Total at Year	Total at Year	First Attributed	Total at Year	First Attributed	Total at Year	
Prior	3.4	3.4	7.2	7.2	82.6	82.6	4.0	4.0	—	—	94.1	94.1	122.4	122.4
2013	1.1	1.7	2.6	7.2	10.3	73.1	0.4	3.3	—	—	—	96.0	5.8	120.4
2014	1.1	1.8	1.5	6.1	23.0	68.4	1.1	3.0	—	—	—	96.0	7.5	118.3
2015	0.3	5.7	—	0.5	21.0	75.3	1.5	4.6	—	5.4	—	96.0	5.3	120.2
Probable Undeveloped														
Light and Medium Crude Oil		Heavy Crude Oil		Conventional Natural Gas		Natural Gas Liquids		Shale Gas		Bitumen		Total Oil Equivalent		
(MMbbl)		(MMbbl)		(Bcf)		(MMbbl)		(Bcf)		(MMbbl)		(MMboe)		
First Attributed	Total at Year	First Attributed	Total at Year	First Attributed	Total at Year	First Attributed	Total at Year	Total at Year	Total at Year	First Attributed	Total at Year	First Attributed	Total at Year	
Prior	9.0	9.0	8.8	8.8	73.5	73.5	5.6	5.6	—	—	165.1	165.1	200.9	200.9
2013	2.4	6.5	1.8	8.0	6.8	68.0	0.6	6.5	—	—	—	163.4	5.9	195.7
2014	1.5	5.7	1.3	6.2	12.6	55.1	0.5	4	—	—	—	163.2	5.4	188.4
2015	1.3	9.4	—	0.7	37.2	103.9	1.5	5.6	—	2.5	—	163.2	9.0	196.6

(1) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.

Substantially all of Harvest's Undeveloped Reserves are based on Harvest's long range development plans for the major assets noted elsewhere in this document. Excluding BlackGold's bitumen Reserves, most of these reserves are expected to be developed between 2017 and 2020. Harvest has little to no development drilling planned in 2016. The development schedule of Harvest's Undeveloped Reserves is linked to processing facility capacity restrictions and capital allocation plans. The capital cost has been taken into account for these programs in the estimated future net revenue.

BlackGold Bitumen

Approximately 80% and 83% of Harvest's Proved Undeveloped and Probable Undeveloped Reserves, respectively, are located on Harvest's BlackGold oil sands property. At the end of 2015, Harvest's BlackGold oil sands project had Proved Undeveloped bitumen reserves of 96.0 MMbbl and Probable Undeveloped bitumen reserves of 163.2 MMbbl. BlackGold Reserves will be recovered by using SAGD methodology.

The BlackGold project requires the construction of a central processing facility ("CPF") that supports SAGD well pads. The BlackGold CPF is designed to last for 25 years of useful life (with up to approximately 35 to 40 years of useful life based on adequate maintenance) while the life of the SAGD well pairs typically range from 7 – 15 years on a declining basis. Therefore, to build a central facility that would process the entire field simultaneously would be neither economic nor environmentally efficient. Due to the high capital and operating costs associated with SAGD production, greater economic value and environmental efficiency are achieved by building a central facility

with optimal capacity that provides for a series of SAGD well pairs to be drilled and produced over the life of the central processing facility.

In the early stages of a SAGD project, a relatively small portion of Proved Reserves are developed as the number of drilled well pairs are limited by the available steam and processing capacity. The Undeveloped Reserves assigned to BlackGold are forecast to be developed over the next 25 years; however, the timing of the conversion of those Reserves from Undeveloped to Developed Reserves depends on when the well pair targeting those Reserves is scheduled during the life of the CPF and steam generators. Development of the Proved Undeveloped Reserves takes place in an orderly manner when existing SAGD well pairs reach production decline phase.

Harvest has delineated BlackGold bitumen Reserves with a high degree of certainty through core hole drilling and seismic data consistent with COGE Handbook guidelines. In most cases, Proved Reserves have been drilled to a density of 16 wells per section, which is in excess of the eight wells per section required for regulatory approval. In addition, regulatory and corporate approvals must be obtained, funding must be in place and a reasonable development timeline must be established for Reserves to be classified as Proved Reserves.

Recognition of probable reserves requires sufficient drilling of stratigraphic wells, well coring and analysis, and geological mapping to establish reservoir suitability for SAGD. The Independent Qualified Reserve Evaluator's standard for probable reserves is a minimum of four to eight stratigraphic wells per section, depending on the depositional environment. The probable reserves related to the BlackGold project are limited to the Phase 2 area.

Phase one start up is currently scheduled for 2017 and will be confirmed or revised in 2017 subject to product pricing and capital plans.

During 2013, Harvest received regulatory approval for Phase 2, however, due to the longer development timeline and the requirement for corporate approval and funding, the Reserves related to Phase 2 have been classified as Probable Reserves instead of Proved Reserves.

Significant Factors or Uncertainties Affecting Reserves Data

The evaluation of Reserves is a continuous process, one that can be significantly impacted by a variety of internal and external influences. Revisions are often required resulting from changes in pricing, economic conditions, regulatory changes, and historical performance. While these factors can be considered and potentially anticipated, certain judgments and assumptions are always required. As new information becomes available these areas are reviewed and revised accordingly. For a discussion of risk factors and uncertainties affecting reserves data, see *Risk Factors – Risks Associated with Reserve Estimates* in the Annual Information Form for the year ended December 31, 2015.

Future Development Costs

The following table sets forth development costs deducted in the estimation of Harvest's Consolidated Entities future net revenue attributable to the reserves categories noted below:

Year	Forecast Prices and Costs (\$ millions)	
	Proved Reserves	Proved Plus Probable Reserves
2016	37	40
2017	244	359
2018	120	194
2019	37	170
2020	73	320
Thereafter	1,093	3,335
Total Undiscounted	1,606	4,417
Total Discounted at 10%	618	1,633

Future development costs are based on a number of factors and assumptions made at a point in time. Actual future development costs could differ materially depending on numerous factors, such as but not limited to changes in supply and demand of crude oil and natural gas, commodity prices, availability and cost of labor, material and equipment, changes in regulatory environment and commercial negotiation. Future development costs will be funded through a combination of cash flow from operating activities, proceeds from dispositions, borrowings under the Credit Facility, and long-term debt issuances. Please refer to the “Liquidity” section in the Management Discussion and Analysis and “Risk Factors” section of the Annual Information Form for the year ended December 31, 2015 for discussions on the risks and uncertainties around availability of future capital resources.

The interest or other costs of external funding are not included in the Reserves and future net revenue estimates and would reduce Reserves and future net revenue to certain extent depending on the source of funding used and the cost of funding at the time. The Corporation does not expect that interest or other funding costs would materially impact future net revenue, Reserves or future development decision though this is subject to some degree of uncertainty. See “Risk Factors” section of the Annual Information Form for the year ended December 31, 2015 for further discussion.

Estimated future downhole costs related to a property have been taken into account by the Independent Qualified Reserves Evaluator in determining Reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom. No allowance was made, however, for reclamation of well sites or the abandonment and reclamation of any facilities. See *Additional Information Concerning Abandonment and Reclamation Costs* in this statement for more information.

OTHER OIL AND GAS INFORMATION

Oil and Natural Gas Properties

Harvest’s Consolidated Entities’ portfolio of significant properties are aggregated into material areas and discussed below. All properties are located onshore in Canada.

In general, the properties include major oil accumulations which benefit from active pressure support due to underlying regional aquifers. Generally, the properties have predictable decline rates with costs of production and oil price key to determining the economic limits of production and ultimately the recoverable Reserves.

Harvest is actively engaged in cost reduction and production and Reserves replacement optimization efforts directed at Reserves addition to extend the economic life of these producing properties beyond the limits used in the Reserves Report. We also are developing new proven Reserves in our core and strategic assets previously not evaluated by the Independent Qualified Reserves Evaluator.

Finally, the estimates of Reserves and future net revenue for individual properties may not reflect the same confidence levels as estimates of Reserves and future net revenue for all properties, due to the effects of aggregation.

Principal Producing Properties at December 31, 2015

Hay River

Hay River was acquired by Harvest on August 2, 2005 and is located approximately 245 miles north west of Grande Prairie in north-eastern British Columbia. In 2015, Hay River produced an average of 4,355 boe/day of 24° API crude oil (including 12 barrels per day of condensate removed from the solution gas stream before that solution gas is reinjected into the reservoir for pressure maintenance) from the Bluesky formation located at a depth of approximately 350 metres. Natural gas produced from this formation, along with produced water, is re-injected for pressure support. Produced emulsion is processed at the central emulsion processing facility with the clean oil transported via pipeline to sales points.

Hay River is a winter-only access area in that drilling operations can only be reasonably undertaken when the ground is frozen (typically between late November and mid-March). The Hay River medium gravity oil production is priced at a discount to the Edmonton Light oil benchmark, contributing to stronger netbacks when compared to

other similar gravity crudes. Harvest has a 100% Working Interest in this operated property. In 2015, Harvest drilled 9 gross 100% Working Interest wells, including 7 horizontal producing wells, 2 water injection wells. Our total Hay capital program for 2015 was \$20.9 million.

Since 2007, Harvest has focused on increasing water injection into the producing Bluesky formation to improve overall pressure support, production and recovery of oil from the reservoir. The reinjection of produced water is now being augmented with additional make-up water from the Gething formation. A gas plant constructed in 2007 was commissioned in the spring of 2008 to eliminate flaring at the site and to manage recovery and reinjection of associated gas. Connection of commercial power to the site was also completed in 2008 which allowed for optimization of the production in the field.

Red Earth

Red Earth is located 200 miles north west of Edmonton, Alberta. Production in 2015 from Red Earth averaged 3,499 boe/d (97% oil), with an average oil quality of 37° to 39° API from the Slave Point, Granite Wash and Gilwood formations.

Production is gathered via Harvest's gathering system and the oil is pipelined to market via the Plains Rainbow Pipeline system.

Harvest continued to build on its 2012 partnership with the Loon Lake First Nations for an option on up to 26 sections of land, by drilling 6 wells in Loon Lake in 2015. All wells were horizontal wells in the Slave Point formation using multi-staged fractured completions.

Our total Red Earth capital program in 2015 was \$25.5 million.

West Central Alberta

West Central Alberta is comprised of properties west of Highway 2, south of Edmonton and north of Calgary. This is primarily a liquids-rich natural gas production area with some oil production. Production in 2015 for the region averaged 10,996 boe/d (65% gas).

Gas gathering, transportation, compression and processing infrastructure is extensive in West Central Alberta and Harvest uses a combination of Harvest's and third party's infrastructures to process and transport its gas and NGLs to market.

Major fields in this area include Caroline (Beaverhill Lake liquids rich 50% H₂S gas), Crossfield (Ellerslie oil and Basal Quartz gas), Markerville (Pekisko, Edmonton Sands, Cardium and Glauconite and Ellerslie) and Rimbey (Glauconite, Ostracod, Notikewin and Cardium). All new liquids-rich gas production and oil production are from stage stimulated horizontal wells except for a highly prolific vertical gas play in the Glauconite formation.

In 2015, Harvest participated in 3 gross wells and 0.2 net wells. Total capital expenditure throughout the area was approximately \$5.0 million mainly associated with the upkeep of the existing infrastructure as well as some abandonment and reclamation work.

East Central Alberta

This area mainly encompasses legacy oil properties from the Saskatchewan / Alberta border to Alberta Highway 2 and between the cities of Edmonton and Calgary. Working interest in these properties is generally over 90%. In 2015, the average production was 2,666 boe/d (82% oil) and is primarily heavy and medium oil from 18° to 32° API. The Corporation's largest group of legacy properties including Bashaw, Bellshill and a number of smaller oilfields are in the region. This area remains largely focussed on cost savings and optimization of current wells and facilities. Harvest continues to invest in pipeline and infrastructure upgrades to repair or replace some of the older equipment in East Central Alberta. Harvest drilled no wells in 2015 in East Central Alberta.

During the year of 2015 Harvest divested Bashaw, Leahurst, Redwater, Metiskow and Czar properties.

Total capital investment in East Central Alberta was approximately \$11.3 million in 2015 primarily related to investments in pipeline and facility upgrades.

Deep Basin (Consolidated Entities)

The Deep Basin lands were acquired from Hunt in early 2011 and has been an area of strong drilling results and reserves success. The Deep Basin is located to the southwest of the city of Grande Prairie in northwest Alberta.

Production in 2015 averaged 8,520 boe/d (92% gas). Harvest saw significant production growth in production volumes during 2015, as the result of increased capital investment tied to new expanded processing and transportation agreement.

Legacy production is from vertical wells completed in multiple zones (Falher, Cardium, Cadotte, Cadomin, Bluesky, Dunvegan, and Gething) and comingled together. Recent drilling activities have been focused on drilling high rate 5 to 10 mmcf/d, stage-stimulated horizontal wells in the Falher formation. In 2015, Harvest participated in 7 gross (3.1 net) wells and added to its land base and expanded its gathering system infrastructure for a net investment of \$62.6 million.

Heavy Oil

Harvest has various working interests in this area, which is located near the town of Lloydminster on the Alberta side of the border and down into Southern Alberta near the city of Medicine Hat. Major properties in this group include Suffield (Glauconite), Lindbergh/Wildmere (Lloyd/Sparky/GP), and Hayter (Dina/Cummings and Sparky).

Production is 12° to 15° API heavy crude oil from Cretaceous aged sandstone formations within the Mannville group. Production averaged 5,225 boe/d (96% oil) in 2015. Harvest drilled 1 gross well in 2015 in the Suffield area, and invested in pipeline and facility upgrades with total net capital expenditures of \$0.7 million.

Production from these wells generally goes to central processing facilities with solution gas conservation and oil is trucked to third party sales points, except for Hayter and Suffield which are pipeline connected. Future plans at Suffield include downspacing pools with additional horizontal wells and assessing the potential impact of water injection for pressure maintenance and enhanced recovery.

Saskatchewan Light Oil

This area includes Harvest's assets in southeast Saskatchewan towards the Manitoba border. The southeast Saskatchewan properties are located approximately 110 miles southeast of Regina with production from the non-stage stimulated horizontal wells in Tilston and Souris Valley formations of Mississippian age. Both of these properties contain high netback light 34° to 39° API oil.

Production in 2015 averaged 2,052 boe/d of light oil. In 2015 capital expenditure totaled \$4.6 million primarily related capital maintenance and facilities.

BlackGold

Harvest acquired a 100% Working Interest of BlackGold in 2010 from KNOC. The area is located in northeast Alberta near Conklin and is in close proximity to a number of major oil sands developments.

In 2015 the construction had been substantially completed, including the building of the CPF plant site, well pads, connecting pipelines and several systems have since been commissioned. Total capital expenditure of \$66.0 million were incurred in 2015.

Harvest's plans for 2016 are to continue with minor pre-commissioning activities and then decide whether or not to proceed to commissioning and steam injection depending on the price outlook for bitumen.

Phase 1 will inject steam for several months and then begin oil production, with a targeted rate of 10,000 boe/d. Phase 2 of the project, which is targeted to increase production capacity to 30,000 bbl/d, received all required regulatory approvals in 2013.

Deep Basin Partnership (Equity Investment)

In April 2014 Harvest entered into two Partnerships with KERR to build a gas plant and develop our natural gas assets in the Bilbo, Karr and Wapiti regions of the Deep Basin Partnership area. Activities and results from these partnerships are reported on an equity basis in Harvest's financial statements.

The partnership saw significant production growth in production volumes during 2015, as the result of increased capital investment. Production for 2015 in the DBP averaged 4,126 boe/d, and Harvest's equity interest in the production was 3,319 boe/d. During 2015, DBP drilled 7 gross (6.27 net) wells in the Deep Basin, targeting the Cardium, Falher and Montney formations. Production from these wells is directed to the Harvest-operated Partnership gas plant. Total capital investment by the partnership in 2015 was \$139.0 million.

Oil and Gas Wells

The following table sets forth the number of oil and gas wells in which Harvest's Consolidated Entities held a Working Interest at December 31, 2015:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing ⁽¹⁾		Producing		Non-Producing ⁽¹⁾	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	2,060	1,578	1,214	911	1,407	492	779	310
British Columbia	427	395	165	101	56	11	97	48
Saskatchewan	390	349	372	326	1	—	39	36
Total	2,877	2,323	1,751	1,338	1,464	503	915	394

(1) Non-producing wells include wells which are capable of producing, but which are currently not producing. Non-producing wells do not include other types of wells such as service wells or wells that have been abandoned.

All of Harvest's oil and gas wells are onshore.

Properties with No Attributed Reserves

The following tables set out Harvest Consolidated Entities' undeveloped land holdings as at December 31, 2015:

	Unproved Properties (Hectares) ⁽¹⁾		
	Gross	Net	Net Hectares with Rights Expiring Within One Year
Alberta	253,060	187,757	41,433
British Columbia	92,936	58,685	4,882
Saskatchewan	9,257	9,012	3,125
Total	355,253	255,454	49,440

(1) For areas where Harvest holds interests in different formations under the same surface area through separate leases, the gross and net hectares are calculated on the individual lease basis.

Harvest conducts ongoing development activity to retain land that would otherwise expire. As a result of this activity, the actual land holdings that will expire within one year may be less than indicated above.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

Harvest has land holdings with no attributed reserves for future exploration and development that are pending the geoscience and engineering analysis to identify and evaluate future prospects. These exploration and development activities are pending the availability of future capital.

Additional Information Concerning Abandonment and Reclamation Costs

Harvest estimates the costs to abandon and reclaim all of its shut-in and producing wells, pipelines and facilities. Harvest's model for estimating the amount and timing of future abandonment and reclamation expenditures was created on an operating area level. Estimated expenditures are based on the Alberta Energy Regulator ("AER")

methodology from 2015 which details the cost of abandonment and reclamation costs in eight specific geographic regions, coupled with our own experience on actual abandonment costs in each region.

Each region was assigned an average cost per well to abandon and reclaim the wells in that area. The cumulative yearly costs that will be incurred for producing wells are based on the reserve lives of each area provided by the Independent Qualified Reserves Evaluator. The cumulative yearly costs that will be incurred for suspended wells are based on AER Directive 13 and Directive 20 guidelines and Harvest's actual experience with abandoning similar wells in each area. Facility abandonment and reclamation costs are scheduled to be incurred in the year following the end of the reserves life of its associated reserves.

Abandonment costs (excluding salvage values) associated with wells to which reserves were attributed, were deducted by the Independent Reserves Evaluator in estimating future net revenue and value in the Reserves Reports.

Tax Horizon

Harvest anticipates that there will be no cash income tax payable prior to 2051. However, this estimate is highly sensitive to variables such as commodity prices, production and the timing of future capital spending. If commodity prices were to strengthen beyond the levels anticipated by the forward market, our tax pools would be utilized more quickly and the Corporation may be required to pay cash income taxes sooner than anticipated.

Costs Incurred

The following table summarizes capital expenditures (net of incentives and net of certain proceeds, including capitalized general and administrative expenses) related to Harvest's Consolidated Entities and Equity Investment for the year ended December 31, 2015:

(\$ millions)	Consolidated Entities			Equity Investment
	Oil & Gas Capital Expenditures (Excluding Oil Sands)	Oil Sands Capital Expenditures	Total Capital Expenditures ⁽¹⁾	Oil & Gas Capital Expenditures
Property acquisition costs ⁽²⁾				
Proved properties	(6.1)	—	(6.1)	41.5
Unproved properties	6.7	—	6.7	5.5
Total property acquisition costs	0.6	—	0.6	47.0
Exploration costs	1.2	—	1.2	—
Development costs	139.7	65.6	205.3	72.1
Total	141.5	65.6	207.1	119.1

(1) Total capital expenditures exclude costs related to corporate assets of \$6.0 million.

Exploration and Development Activities

The following table sets forth the number of Exploratory and Development Wells completed by Harvest's Consolidated Entities during 2015:

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil Wells	—	—	13.0	13.0
Gas Wells	—	—	10.0	3.2
Service Wells	—	—	2.0	2.0
Stratigraphic test wells	—	—	—	—
Dry Holes	—	—	1.0	1.0
Total Wells	—	—	26.0	19.2

2016 Capital Expenditure Plan

The primary areas of focus for Harvest's Upstream and BlackGold capital program during 2016 are the following:

- BlackGold – Continue minor pre-commissioning activities ;
- Hay River – Optimize existing production by cleaning out some wellbores of accumulated mud from prior year's drilling;
- Deep Basin Area (including Deep Basin Partnership Area) – Participate in two partner operated drills during the winter of 2015/16 and drill and case two Montney wells inside the DB Partnership for completion and tie-in in 2017.

Incremental Exploitation and Development Potential

Management of Harvest has identified numerous development opportunities, many of which provide the potential for capital investment and incremental production beyond that identified in the Reserves Reports. These opportunities include:

- Implementation or optimization of enhanced water floods in selected pools such as Hay River, Red Earth and Cecil resulting in increased production and recovery;
- Uphole completions of bypassed or untested reserves in existing wellbores, including recompletion of existing shut-in wells to access undrained reserves;
- Selected infill and step-out development drilling opportunities across most of Harvest's core properties for various proven targets generally defined by 3-D seismic;
- Numerous exploratory opportunities defined by seismic from which value might be extracted by sale, farmout or joint venture;
- Management of dry gas and high operating cost wells currently shut in due to low commodity prices to preserve reserves to be produced at a time when prices improve; and
- Utilizing multistage fractured technology in horizontal wells to increase oil recovery from tight oil and gas formations at Red Earth (Slave Point Formation), Deep Basin (Falher and Montney Formations) and Rimbey/West Central Area (Cardium, Glauconite, Viking, Ostracod, Notikewin, Wilrich Formations).

Production Estimates

The following table sets forth the forecast volume of production from gross reserves for Harvest's Consolidated Entities' per the 2015 year-end Reserves Report:

	2016 Production Forecast Before Royalty Interests							Total ⁽¹⁾ boe/d
	Light and Medium	Heavy Oil	Conventional Bitumen	Natural Gas	Shale Gas	Coal Bed Methane	Natural Gas Liquids	
	bbl/d	bbl/d	bbl/d	mcf/d	mcf/d	mcf/d	bbl/d	
Proved Producing	11,410	5,672	—	82,466	—	50	3,153	33,988
Proved Developed Non-Producing	206	83	—	1,810	—	—	63	654
Proved Undeveloped	855	—	—	15	—	—	3	859
Total Proved	12,471	5,755	—	84,291	—	50	3,219	35,501
Total Probable	550	201	—	4,174	—	1	130	1,577
Total Proved Plus Probable	13,021	5,956	—	88,465	—	51	3,349	37,078

(1) West Central Alberta 2016 production forecast before royalties on a gross proved and gross probable basis are 9,526 boe/d and 235 boe/d respectively.

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 for Harvest's Consolidated Entities indicated below:

Average Daily Production Volumes					
2015					
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil (bbl/d)	9,832	8,695	8,633	7,934	8,768
Heavy Oil (bbl/d)	12,058	11,969	11,155	10,044	11,301
Total Oil (bbl/d)	21,890	20,664	19,788	17,978	20,069
NGLs (bbl/d)	4,231	3,779	3,998	3,820	3,956
Natural Gas(mcf/d)	105,887	103,639	117,419	98,055	106,259
Total Daily Production (boe/d)	43,770	41,716	43,356	38,141	41,735

Total Sales Production					
2015					
	Q1	Q2	Q3	Q4	Total
Light and Medium Oil (MMbbl)	0.9	0.8	0.8	0.7	3.2
Heavy Oil (MMbbl)	1.1	1.1	1.0	0.9	4.1
Total Oil (MMbbl)	2.0	1.9	1.8	1.6	7.3
NGLs (MMbbl)	0.4	0.3	0.4	0.3	1.4
Natural Gas (Bcf)	9.5	9.4	10.8	9.1	38.8
Total Production (MMboe)	3.9	3.8	4.0	3.5	15.2

Average Sales Prices Received					
2015					
	Q1	Q2	Q3	Q4	Total
Light & Medium oil (\$/bbl)	45.56	58.68	48.78	45.52	49.59
Heavy Oil (\$/bbl) ⁽¹⁾	39.53	53.22	41.23	35.63	42.69
Total Oil (\$/bbl)	42.24	55.52	44.52	40.00	45.71
NGLs (\$/bbl)	30.91	33.45	26.56	26.61	29.36
Natural Gas (\$/mcf) ⁽¹⁾	2.81	2.54	2.80	2.30	2.62
Total (\$/boe)	31.85	37.85	31.47	27.89	32.33

Royalties Paid					
2015					
	Q1	Q2	Q3	Q4	Total
(\$ millions)					
Light & Medium Oil	5.7	4.4	4.1	3.7	17.9
Heavy Oil	5.0	4.7	4.4	3.0	17.1
NGLs	1.0	1.5	1.1	2.1	5.7
Natural gas	1.4	1.6	1.9	3.1	8.0
Total	13.1	12.2	11.5	11.9	48.7
Light & Medium Oil (\$/bbl)	6.44	5.56	5.16	5.07	5.59
Heavy Oil (\$/bbl)	4.56	4.32	4.29	3.25	4.15
NGLs (\$/bbl)	2.63	4.36	2.99	5.98	3.95
Natural gas (\$/boe)	0.88	1.02	1.06	2.06	1.24
Total (\$/boe)	3.34	3.19	2.89	3.38	3.19

	Operating Expenses				
	2015				
	Q1	Q2	Q3	Q4	Total
(\$ millions)					
Light & Medium Oil	22.0	18.5	17.1	14.8	72.4
Heavy Oil	26.7	20.4	15.4	16.8	79.3
NGLs	5.2	4.5	4.3	0.0	14.0
Natural gas	18.6	22.2	24.2	20.9	85.8
Total	72.5	65.6	61.0	52.5	251.5
Light & Medium Oil (\$/bbl)	24.86	23.40	21.51	20.25	22.62
Heavy Oil (\$/bbl)	24.33	18.72	15.00	18.19	19.23
NGLs (\$/boe)	13.65	13.12	11.72	0.05	9.70
Natural Gas (\$/boe)	11.71	14.10	13.43	13.91	13.27
Total (\$/boe)	18.40	17.29	15.28	14.96	16.50

	Netback Received ⁽²⁾⁽³⁾				
	2015				
	Q1	Q2	Q3	Q4	Total
Light & Medium Oil (\$/bbl)	14.26	29.72	22.11	20.20	21.38
Heavy Oil (\$/bbl) ⁽¹⁾	10.64	30.18	21.94	14.19	19.32
NGLs (\$/bbl)	14.63	15.97	11.85	20.58	15.71
Natural Gas (\$/boe) ⁽¹⁾	4.27	0.10	2.32	(2.15)	1.23
Total (\$/boe)	10.11	17.37	13.30	9.55	12.64

(1) Before gains or losses on risk management contracts.

(2) Netbacks are calculated by subtracting royalties and operating expenses before gains or losses on risk management contracts and transportation expenses.

(3) These are non-GAAP measures. Please refer to "Non-GAAP Measures" section.

2015 Historical Production by Material Area for Harvest's Consolidated Entities

Material Area	Light & Medium Crude	Heavy Oil bbl/d	Natural Gas mcf/d	NGLs bbl/d	Average Daily Production boe/d
	Oil bbl/d				
Hay River	—	4,343	—	12	4,355
Red Earth	3,384	—	337	58	3,499
West Central Alberta	758	197	42,734	2,918	10,996
East Central Alberta	1,594	596	2,379	79	2,666
Deep Basin	61	—	46,864	648	8,520
Heavy Oil	—	4,943	1,294	66	5,225
Saskatchewan Light Oil	2,042	—	58	—	2,052
Other	928	1,222	12,594	175	4,423
Total	8,768	11,301	106,260	3,956	41,735

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

All forward-looking statements in this document and in certain documents incorporated by reference herein, are based on assumptions and the Corporation's (as defined below) view of future events which reflect information available at the time the assumption was made. Certain statements contained in this document constitute forward-looking statements. The use of any of the words "budget", "outlook", "seek", "plan", "project", "predict", "potential", "intend", "anticipate", "continue", "estimate", "expect", "may", "will", "assume", "should", "could", "might", "believe", "target", "forecast" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Management of the Corporation believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included herein should not be unduly relied upon. These statements speak only as of the date hereof or at the date specified in the documents incorporated by reference into this document.

In particular, this document contains forward-looking statements pertaining to the following:

- oil and natural gas production levels;
- capital expenditure programs and related spending;
- factors upon which to decide whether or not to undertake a capital project;
- possible commerciality of capital projects;
- the quantity and net future revenues of the oil and natural gas reserves;
- projections of commodity prices and costs;
- future cash flows from reserves;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and continually add reserves through exploration, development and acquisitions;
- tax horizon;
- expected abandonment and reclamation costs and
- treatment under governmental regulatory regimes including but not limited to royalties, environmental and taxation.

With respect to forward-looking statements contained in this Form, Harvest has made assumptions regarding, among other things:

- future oil and natural gas prices and differentials among light, medium and heavy oil prices;
- Harvest's ability to conduct its operations and achieve results of operations as anticipated;
- Harvest's ability to achieve the expected results from its development plans and sustaining maintenance programs;
- the continued availability of adequate cash flow and debt and/or equity financing to fund Harvest's capital and operating requirements as needed;
- Harvest's ability to obtain financing with favorable terms;
- the general continuance of current or, where applicable, assumed industry conditions;
- the general continuation of assumed tax, royalty and regulatory regimes;
- the accuracy of the Corporation's reserves;
- the ability to obtain equipment in a timely manner to carry out development and other capital activities;
- the ability to market oil and natural gas successfully to current and new customers;
- the cost of expanding Harvest's property holdings;
- the impact of increasing competition; and
- the ability to add production and reserves through development and exploitation activities.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this document:

- volatility in market prices for oil and natural gas;
- determination of global economy;
- adverse changes to law and regulations;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates; and
- failure to realize the anticipated benefits of acquisitions.

Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this document or otherwise. Reader should also carefully consider the matters discussed under the heading “Forward-Looking Statements” and “Risk Factors” in the Annual Information Form for the year ended December 31, 2015.

NON-GAAP MEASURES

Throughout this document, Harvest has referred to certain measures of financial performance that are not specifically defined under GAAP such as “Netbacks”.

“Netbacks” are reported on a per boe basis and used extensively in the Canadian energy sector for comparative purposes. “Netbacks” include revenues, royalties and operating expenses, and realized gains or losses on risk management contracts. The non-GAAP measures do not have any standardized meaning prescribed by GAAP and may not be comparable to similar measures used by other issuers.

FORM 51-101F2: REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR – HARVEST OPERATIONS CORP.

To the board of directors of Harvest Operations Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, 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.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. 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.
5. The following table shows the net present value of 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 for the year ended December 31, 2015, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Description	Location of Reserves	Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate) (\$ millions)			
				Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	December 31, 2015	Harvest Operations	Canada	-	1,444	-	1,444

6. 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 reviewed by did not audit or evaluate.
7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after their respective preparation dates.
8. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our reports referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 12, 2016

(Signed) "Myron J. Hladyshevsky", P. Eng.

Vice President

FORM 51-101F2: REPORT ON RESERVES DATA AND CONTINGENT RESOURCES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR – HARVEST OPERATIONS CORP.

To the board of directors of Harvest Operations Corp. (the "Company"):

1 We have evaluated the Company's reserves data and contingent resources data as at December 31, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, estimated using forecast prices and costs. The contingent resources data are risked estimates of volume of contingent resources and related risked net present value of future net revenue as at December 31, 2015, estimated using forecast prices and costs.

2. The reserves data and contingent resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data and contingent resources data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data and contingent resources data are free of material misstatement. An evaluation also includes assessing whether the reserves data and contingent resources data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of 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 for the year ended December 31, 2015, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Description	Location of Reserves	Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate) (\$ millions)			
				Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	December 31, 2015	BlackGold	Canada	-	1,154	-	1,154

6. The following tables set forth the risked volume and risked net present value of future net revenue of contingent resources (before deduction of income taxes) attributed to contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data that we have evaluated and reported on to the Company's board of directors:

Risked Net Present Value of Future Net
Revenue
(before income taxes, 10% discount rate)
(\$ millions)

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Description	Location of Reserves	Risked Volume (Mboe)	Audited	Evaluated	Total
Development Pending Contingent Resources (2C)	GLJ Petroleum Consultants Ltd.	December 31, 2015	BlackGold	Canada	23,539		19.6	19.6

7. In our opinion, the reserves data and contingent resources data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data and contingent resources data that we reviewed but did not audit or evaluate.

8. We have no responsibility to update our reports referred to in paragraphs 5 and 6 for events and circumstances occurring after the effective date of our reports.

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

Executed as to our reports referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 17, 2016

(Signed) "Myron J. Hladyshevsky", P. Eng.

Vice President

FORM 51-101F2: REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR – DEEP BASIN PARTNERSHIP

To the board of directors of Harvest Operations Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, 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.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
4. 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.
5. The following table shows the net present value of 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 for the year ended December 31, 2015, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Effective Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate)(\$ millions)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	Deep Basin Partnership (HOC interest) December 31, 2015	Canada	-	174	-	174

6. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.
8. 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 reports referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 12, 2016

(Signed) "Myron J. Hladyshevsky", P. Eng.

Vice President

FORM 51-101F3: REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Harvest Operations Corp. (the "Corporation") is responsible for the preparation and disclosure of information with respect to the Corporation'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, 2015, estimated using forecast prices and costs.

Independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented above in Form 51-101F2.

The Upstream Reserves, Safety & Environment Committee (the "RSE Committee") of the board of directors of the Corporation has:

- a) reviewed the Corporation'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 RSE Committee has reviewed the Corporation'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 RSE Committee, approved:

- a) the content and filing with securities regulatory authorities of Form 51-101F1 containing the reserves data and other oil and gas information;
- b) the filing of Form 51-101F2 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.

(Signed)
Piljong Sung
Interim President & CEO

(Signed)
Taeheon Jang
Deputy Chief Operating Officer and Vice President,
BlackGold

(Signed)
Allan Buchignani
Director

(Signed)
Richard Kines
Director

March 29, 2016