SINOPEC DAYLIGHT ENERGY LTD.
2016 Annual Summary Reserve Report

Disclosure of Reserves Data

The reserves data (the "Reserves Data") set forth below in this reserves report (the "Report") for Sinopec Daylight Energy Ltd. ("Sinopec Daylight" or the "Company") is based upon an independent evaluation by McDaniel & Associates Consultants Limited ("McDaniel") with an effective date of December 31, 2016 contained in the McDaniel reserve report ("McDaniel Report") dated February 20, 2017. The opening reserves balances represent the reserves for Sinopec Daylight at December 31, 2015. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Company and the net present values of future net revenue for these reserves using forecast prices and costs. The McDaniel Report has been prepared in accordance with the standards contained in the COGE Handbook and National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*. We engaged McDaniel to provide an evaluation of proved and proved plus probable reserves and no request was made to evaluate possible reserves.

All of Sinopec Daylight's reserves are in Canada, and specifically in the provinces of Alberta and British Columbia.

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 forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of Sinopec Daylight'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 liquids reserves may be greater than or less than the estimates provided herein.

Abbreviations and Conversions

AECO	physical storage and trading hub for natural gas on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various Alberta index prices
API	American Petroleum Institute
API	measure of the density or gravity of liquid petroleum products derived from a specific gravity
Bbl	barrel
Bbl/d	barrels per day
Bcf	billion cubic feet
boe	barrels of oil equivalent converting 6 Mcf of natural gas or one barrel of natural gas liquids to one barrel of oil equivalent
boe/d	barrels of oil equivalent per day
GJ	Gigajoule
MBbl	one thousand barrels
Mboe	one thousand barrels of oil equivalent
MMboe	one million barrels of oil equivalent
Mcf	one thousand cubic feet
m^3	cubic meters
Mcf/d	one thousand cubic feet per day
MMBtu	one million British Thermal Units
MMcf	one million cubic feet
MMcf/d	one million cubic feet per day
MMBbl	one million barrels
M$	one thousand dollars
MM$	one million dollars
NGLs	natural gas liquids
WTI	West Texas Intermediate crude oil that serves as the benchmark crude oil for the NYMEX crude oil contract delivered in Cushing, Oklahoma

FORWARD-LOOKING STATEMENTS

Certain statements contained within this Report constitute forward-looking statements. These statements relate to future events or future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. 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. We believe the expectations reflected in these 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 in this Report should not be unduly relied upon. These statements speak only as of the date of this Report.

The actual results could differ materially from those anticipated in forward-looking statements as a result of certain risk factors, including those set forth below:

- volatility in market prices for oil, NGLs and natural gas;
- counterparty credit risk;
- changes or fluctuations in oil, NGLs and natural gas production levels;
- infrastructure or transportation constraints for oil, NGLs or natural gas;
- liabilities inherent in and as a result of oil and natural gas operations;
- adverse regulatory rulings, orders and decisions;
- attracting, retaining and motivating skilled personnel;
- uncertainties associated with estimating oil and natural gas reserves;
- fluctuations in foreign exchange or interest rates;
- actions by governmental or regulatory authorities including changes in royalty structures and programs and income tax laws or changes in tax laws and incentive programs relating to the oil and natural gas industry generally;
- limitations on insurance;
- changes in accounting policies and standards;
- changes in environmental or other legislation applicable to our operations including environmental laws and regulations associated with drilling and completion technologies, and our ability to comply with current and future environmental and other laws; and
- geological, technical, drilling and processing problems and other difficulties in producing oil, NGLs and natural gas reserves.

Statements relating to "reserves" or "resources" are by their nature deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

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

To Convert From	To	Multiply By
cubic meters	cubic feet	35.315
Mcf	cubic meters	28.174
Bbl	cubic meters	0.159
cubic meters	Bbl	6.290
Feet	Meters	0.305
Meters	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

Summary of Reserves

The following tables summarize, as at December 31, 2016, Sinopec Daylight's oil, natural gas liquids and natural gas reserves and the estimated net present values of future net cash revenues associated with such reserves, together with certain information, estimates and assumptions associated with such reserve estimates, as contained in the McDaniel Report. The data contained in the tables set out below is a summary of the evaluations, and as a result, the numbers in the tables may not add due to rounding.

Reserves	**Light and Medium Oil**		**Heavy Oil**		**Tight Oil**	
	Gross *(MBbl)*	**Net** *(MBbl)*	**Gross** *(MBbl)*	**Net** *(MBbl)*	**Gross** *(MBbl)*	**Net** *(MBbl)*
Proved						
Developed producing	10,010	8,267	24	23	166	137
Developed non-producing	1,182	911	2	2	-	-
Undeveloped	5,639	5,043	-	-	-	-
Total Proved	16,830	14,221	26	25	166	137
Probable	5,549	4,341	10	10	3,064	2,591
Total proved plus probable	**22,380**	**18,562**	**36**	**34**	**3,230**	**2,728**

Reserves	**Natural Gas**		**Coalbed Methane**		**Shale Gas**	
	Gross *(MMcf)*	**Net** *(MMcf)*	**Gross** *(MMcf)*	**Net** *(MMcf)*	**Gross** *(MMcf)*	**Net** *(MMcf)*
Proved						
Developed producing	133,768	120,852	172	163	45,868	40,673
Developed non-producing	4,615	3,987	-	-	7,762	7,335
Undeveloped	50,964	46,996	-	-	325,935	292,640
Total Proved	189,346	171,835	172	163	379,565	340,649
Probable	123,034	111,383	67	63	471,117	414,945
Total proved plus probable	**312,380**	**283,217**	**239**	**226**	**850,681**	**755,594**

Reserves	Natural Gas Liquids		Total	
	Gross	Net	Gross	Net
	(MBbl)	*(MBbl)*	*(Mboe)*	*(Mboe)*
Proved				
Developed producing	7,497	5,545	47,665	40,920
Developed non-producing	930	700	4,176	3,500
Undeveloped	20,443	16,801	88,898	78,450
Total Proved	28,870	23,046	140,740	122,870
Probable	28,728	22,527	136,388	117,200
Total proved plus probable	**57,598**	**45,572**	**277,127**	**240,070**

Net Present Value of Future Net Revenue (before income taxes)

(000s) discounted at	0%	5%	10%	15%	20%
Proved					
Developed producing	$664,764	$545,836	$462,783	$403,103	$358,655
Developed non-producing	$59,594	$46,208	$37,661	$31,821	$27,590
Undeveloped	$882,518	$504,244	$288,662	$160,035	$79,833
Total Proved	$1,606,877	$1,096,288	$789,106	$594,959	$466,078
Probable	$2,021,772	$1,197,028	$761,842	$511,763	$357,899
Total proved plus probable	**$3,628,648**	**$2,293,316**	**$1,550,948**	**$1,106,723**	**$823,977**

Net Present Value of Future Net Revenue (after income taxes)

(000s) discounted at	0%	5%	10%	15%	20%
Proved					
Developed producing	$664,764	$545,836	$462,783	$403,103	$358,655
Developed non-producing	$59,594	$46,208	$37,661	$31,821	$27,590
Undeveloped	$882,518	$504,244	$288,662	$160,035	$79,833
Total Proved	$1,606,877	$1,096,288	$789,106	$594,959	$466,078
Probable	$1,796,318	$1,093,883	$711,295	$485,551	$343,652
Total proved plus probable	**$3,403,195**	**$2,190,171**	**$1,500,401**	**$1,080,511**	**$809,730**

Future Net Revenue (undiscounted)

(000s)	Revenue	Royalties	Operating Costs	Development Costs	Abandon-ment and Reclamation Costs	Future Net Revenue Before Income Taxes	Future Income Taxes	Future Net Revenue After Income Taxes
Proved								
Developed producing	$1,884,351	$225,211	$909,248	$1,193	$83,935	$664,764	$0	$664,764
Developed non-producing	$196,204	$36,719	$83,653	$8,342	$7,895	$59,594	$0	$59,594
Undeveloped	$3,406,088	$397,918	$1,163,388	$923,425	$38,839	$882,518	$0	$882,518
Total Proved	$5,486,643	$659,848	$2,156,289	$932,960	$130,669	$1,606,877	$0	$1,606,877
Probable	$5,319,027	$791,844	$1,762,165	$711,209	$32,037	$2,021,772	$225,453	$1,796,318
Total proved plus probable	**$10,805,669**	**$1,451,692**	**$3,918,454**	**$1,644,169**	**$162,707**	**$3,628,648**	**$225,453**	**$3,403,195**

Future Net Revenue by Production Group (discounted at 10%)	Future Net Revenue before Income Taxes *(000s)*	Unit Value[3] *($/boe or $/Mcf)*
Proved		
Light and medium crude oil[1]	$194,777	$13.81
Heavy oil[1]	$106	$4.24
Tight oil[1]	$3,964	$28.97
Natural gas[2] (Non Assoc. & Assoc.)	$196,258	$1.33
Coalbed methane	($6)	($0.04)
Shale Gas	$394,007	$1.16
Total Proved	$789,106	
Proved plus probable		
Light and medium crude oil[1]	$301,986	$16.41
Heavy oil[1]	$173	$5.04
Tight oil[1]	$26,463	$9.70
Natural gas[2] (Non Assoc. & Assoc.)	$267,871	$1.07
Coalbed methane	$21	$0.09
Shale Gas	$954,434	$1.34
Total Proved plus probable	$1,550,948	

(1) Including solution gas and other by-products
(2) Including by-products but excluding natural gas from oil wells
(3) Calculated using net oil or net gas reserves and forecast prices and cost assumptions

Pricing Assumptions

The forecast cost and price assumptions include increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. The estimated future net revenue to be derived from the production of the reserves includes an inflation rate assumption of 2% per year together with the following price forecasts supplied by McDaniel.

Year	West Texas Intermediate Crude Oil *($US/Bbl)*	Edmonton par Crude Oil *($Cdn/Bbl)*	Natural Gas At AECO *($Cdn/MMbtu)*	Foreign Exchange *($US/$Cdn)*
2017	$55.00	$69.80	$3.40	0.75
2018	$58.70	$72.70	$3.15	0.78
2019	$62.40	$75.50	$3.30	0.80
2020	$69.00	$81.10	$3.60	0.83
2021	$75.80	$86.60	$3.90	0.85
2022	$77.30	$88.30	$3.95	0.85
2023	$78.80	$90.00	$4.10	0.85
2024	$80.40	$91.80	$4.25	0.85
2025	$82.00	$93.70	$4.30	0.85
2026	$83.70	$95.60	$4.40	0.85
2027	$85.30	$97.40	$4.50	0.85
2028	$87.00	$99.40	$4.60	0.85
2029	$88.80	$101.40	$4.65	0.85
2030	$90.60	$103.50	$4.75	0.85
2031 Escalation of 2% thereafter	$92.40	$105.50	$4.85	0.85

Weighted average historical prices realized by Sinopec Daylight for the year ended December 31, 2016 were $2.60 per Mcf for natural gas, $48.08 per Bbl for light oil and $7.54 per Bbl for NGLs.

Reserves Reconciliation

Reconciliation of Gross Reserves

	Light and Medium Oil[1]			Heavy Oil		
	Proved (MBbl)	Probable (MBbl)	Proved plus Probable (MBbl)	Proved (MBbl)	Probable (MBbl)	Proved plus Probable (MBbl)
December 31, 2015	19,599	7,595	27,193	45	14	59
Extensions and improved recovery	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-
Technical revisions	-1,022	-1,994	-3,016	2	-0	2
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Expired Leases	-	-	-	-	-	-
Economic factors	-323	-51	-374	-3	-3	-6
Production	-1,423	-	-1,423	-18	-	-18
December 31, 2016	**16,830**	**5,549**	**22,380**	**26**	**10**	**36**

Reconciliation of Gross Reserves

	Tight Oil[1]			Natural Gas Liquids		
	Proved (MBbl)	Probable (MBbl)	Proved plus Probable (MBbl)	Proved (MBbl)	Probable (MBbl)	Proved plus Probable (MBbl)
December 31, 2015	315	95	410	26,406	22,366	48,772
Extensions and improved recovery	-	3,004	3,004	4,290	3,370	7,660
Infill Drilling	-	-	-	-	-	-
Technical revisions	-77	-28	-105	729	3,621	4,350
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-85	-64	-149
Expired Leases	-	-	-	-	-	-
Economic factors	-10	-6	-16	-819	-565	-1,384
Production	-62	-	-62	-1,652	-	-1,652
December 31, 2016	**166**	**3,064**	**3,230**	**28,870**	**28,728**	**57,598**

Reconciliation of Gross Reserves	Associated and Non-Associated Gas[(2)]			Shale Gas[(2)]		
	Proved (MMcf)	Probable (MMcf)	Proved plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved plus Probable (MMcf)
December 31, 2015	253,237	164,054	417,291	315,278	309,170	624,448
Extensions and improved recovery	8,530	45,102	53,632	60,874	36,854	97,728
Infill Drilling	-	-	-	-	-	-
Technical revisions	-11,800	-126	-11,926	15,195	84,053	99,249
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-8,751	-6,601	-15,351	-	-	-
Expired Leases	-	-	-	-	-	-
Economic factors	-19,942	-35,983	-55,926	-6,230	-2,373	-8,603
Production	-29,964	-	-29,964	-7,517	-	-7,517
December 31, 2016	**191,310**	**166,446**	**357,756**	**377,601**	**427,704**	**805,305**

Reconciliation of Gross Reserves	Coalbed Methane			Oil Equivalent		
	Proved (MMcf)	Probable (MMcf)	Proved plus Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved plus Probable (Mboe)
December 31, 2015	467	118	585	141,195	108,959	250,154
Extensions and improved recovery	-	-	-	15,858	20,033	35,891
Infill Drilling	-	-	-	-	-	-
Technical revisions	-167	-18	-185	170	15,583	15,753
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-1,543	-1,164	-2,707
Expired Leases	-	-	-	-	-	-
Economic factors	-79	-34	-112	-5,530	-7,024	-12,554
Production	-49	-	-49	-9,410	-	-9,410
December 31, 2016	**172**	**67**	**239**	**140,740**	**136,387**	**277,127**

(1) Reclassified 315MBbl Proved, 410MBbl Proved plus Probable Light and Medium Oil as Tight Oil
(2) Reclassified 1,439MMcf Proved, 1,792MMcf Proved plus Probable Associated and Non-Associated Gas as Shale Gas

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by McDaniel in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to place them on production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to place them on production.

We do not intend to carry proved undeveloped reserves for long periods of time unless there is a good reason not to produce these reserves in the short term. Where there is sufficient economic justification, we intend to take steps to accelerate and enhance production. These steps could involve dually completing and/or re-drilling to twin wells for secondary zones.

About 33% of our probable reserves are attributed to better performance of proved wells. The remaining 67% results from identified step-out drilling locations, recompletions of existing wells and tie-in of additional reserves. While these assets do not yet meet the required confidence factor for a booking in the proved category, they are anticipated to be developed in the near term.

For the year ended December 31, 2016, -$945 thousand was spent on capital expenditures including land and property acquisitions, net of dispositions. A portion of the 2017 development capital is planned to be used to convert proved undeveloped reserves and probable reserves into proved developed producing reserves. Allocating capital to properties and timing of development is based on the economics and performance of the respective properties.

We plan to continue pursuing development opportunities such as drilling, completions and facilities upgrades in order to convert proved undeveloped and probable reserves into proved developed producing reserves. In instances where land rights are expected to expire within one year, we may engage in farmout arrangements which would eliminate the potential expiry and possibly result in certain proved undeveloped and probable reserves becoming proved developed producing reserves.

There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals).

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of current proved undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time. In the following table, "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.

Proved Undeveloped Reserves	**Light and Medium Oil**		**Heavy Oil**		**Tight Oil**	
	First Attributed *(MBbl)*	**Total at Year-end** *(MBbl)*	**First Attributed** *(MBbl)*	**Total at Year-end** *(MBbl)*	**First Attributed** *(MBbl)*	**Total at Year-end** *(MBbl)*
2013	455	8,215	-	-	-	-
2014	158	5,874	-	-	-	-
2015	212	7,494	-	-	-	-
2016	-	5,639	-	-	-	-

Proved Undeveloped Reserves	Assoc. and Non-Assoc. Gas		Shale Gas		Natural Gas Liquids	
	First Attributed (MMcf)	Total at Year-end (MMcf)	First Attributed (MMcf)	Total at Year-end (MMcf)	First Attributed (MBbl)	Total at Year-end (MBbl)
2013	76,646	304,769	-	-	4,336	13,578
2014	4,322	306,415	1351	3401	997	14,999
2015	8,621	91,724	-	274,327	912	18,140
2016	5,213	50,963	-	325,935	685	20,443

Proved Undeveloped Reserves	Oil Equivalent	
	First Attributed (Mboe)	Total at Year-end (Mboe)
2013	17,555	72,588
2014	2,101	72,509
2015	2,561	86,643
2016	1,554	88,898

Approximately 87% of Sinopec Daylight's future capital associated with proved undeveloped reserves is scheduled for expenditure in 2017 to 2021. The major areas of development are the Brazeau and Wapiti properties, which represent 85% of the total proved undeveloped future development costs and 91% of the total proved undeveloped reserves. The remaining proved undeveloped capital and reserves are primarily associated with the Fox Creek (Duvernay), Elmworth, Warburg, Tomahawk, and Marlboro areas.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of current probable undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time. In the following table, "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.

Probable Undeveloped Reserves	Light and Medium Oil		Heavy Oil		Tight Oil	
	First Attributed *(MBbl)*	Total at Year-end *(MBbl)*	First Attributed *(MBbl)*	Total at Year-end *(MBbl)*	First Attributed *(MBbl)*	Total at Year-end *(MBbl)*
2013	437	8,097	-	95	-	-
2014	44	4,788	-	-	-	-
2015	321	2,786	-	-	-	-
2016	60	1,899	-	-	3,004	3,004

Probable Undeveloped Reserves	Assoc. and Non-Assoc. Gas		Shale Gas		Natural Gas Liquids	
	First Attributed *(MMcf)*	Total at Year-end *(MMcf)*	First Attributed *(MMcf)*	Total at Year-end *(MMcf)*	First Attributed *(MBbl)*	Total at Year-end *(MBbl)*
2013	57,293	367,468	8415	8415	2,630	12,808
2014	82,053	395,068	3,279	10,661	5,123	19,398
2015	1,926	104,138	-	296,654	119	19,755
2016	1,592	125,477	-	414,339	1,495	26,352

Probable Undeveloped Reserves	Oil Equivalent	
	First Attributed *(Mboe)*	Total at Year-end *(Mboe)*
2013	13,624	83,647
2014	19,389	91,808
2015	761	89,339
2016	4,824	121,224

Approximately 72% of Sinopec Daylight's future capital associated with proved plus probable undeveloped reserves is scheduled for expenditure in 2017 and 2021. The major areas of development are the Brazeau and Wapiti properties, which represent 70% of the total proved plus probable undeveloped future development costs and 82% of the total proved plus probable undeveloped reserves. The remaining proved plus probable undeveloped capital and reserves are primarily associated with the Karr, Elmworth, Fox Creek (Duvernay), Warburg, Tomahawk, Medicine Lodge, and Marlboro areas.

Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently complex and such evaluations are estimates only. Our reserves have been evaluated by McDaniel, an independent engineering firm. The reserve evaluation process requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, geological evaluation, engineering data, prices and economic conditions. These factors and assumptions include among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves. As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative. High operating costs substantially reduce our netback, which in turn reduces the amount of cash available for reinvestment in drilling opportunities. This becomes most relevant during periods of low commodity prices when profits are more significantly impacted by high costs.

Our oil and gas properties have no material extraordinary risks or uncertainties beyond those which are inherent in other oil and gas producing companies.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the future net revenue attributable to the reserve categories noted below.

Future Development Costs (undiscounted) *(000s)*	**Proved Reserves**	**Proved Plus Probable Reserves**
2017	$63,638	$69,223
2018	$157,504	$210,768
2019	$153,527	$273,702
2020	$226,027	$350,428
2021	$214,006	$274,600
Remaining	$118,257	$465,449
Total	**$932,960**	**$1,644,169**

Future development costs are capital expenditures required in the future for us to convert proved non-producing reserves and probable reserves into proved developed producing reserves. We anticipate using a combination of internally generated cash provided by operating activities, and, as required, financing from Sinopec International Petroleum Exploration and Production Corporation ("SIPC") and external sources to fund these future development costs. Sinopec Daylight has the support of its operating parent, SIPC, which provides financial support as required. Based on the commodity price and cost assumptions adopted for the forecast prices and costs case, all the expenditures included in the future development costs are economic as they enhance the net present values of the proved developed producing reserves.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth herein and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any of these properties uneconomic.

Overview

Our operational strategies and activities are directed toward maximizing value over the long-term. We intend to utilize our extensive operating experience and employ prudent oil and natural gas business practices to increase value through development and optimization activities on both existing and acquired oil and natural gas properties. We expect to achieve this value creation through an active development program directed towards lower risk development, continuous optimization of our assets and active management of risk.

Optimization of our assets will take the form of debottlenecking, compression, installation or enhancement of artificial lift, water injection, fluid handling and fluid processing, facility optimization, and other activities. These activities are usually smaller projects with attractive rates of return given the limited capital investment required and rapid payback. We expect to use a variety of technical and operating experts, both internal and external, to achieve these results.

We currently focus our development activities in the Western Canadian Sedimentary Basin. Our development activities are expected to be funded by internally generated cash provided by operating activities, intercompany financing and external sources. We do not anticipate that the costs of funding these development activities will have a material effect on our disclosed oil and gas reserves or future net revenue attributable to those reserves.

Description of Principal Oil and Natural Gas Properties

The following is a description of the principal oil and natural gas properties in which we have an interest. Unless otherwise specified, production estimates, gross and net acres and well count information are as at December 31, 2016. Reserve amounts are stated, before deduction of royalties as at December 31, 2016, based on forecast cost and price assumptions as evaluated in the McDaniel Report. **The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties due to the effects of aggregation.**

Greater Pembina Business Unit

The Greater Pembina BU consists of Sinopec Daylight's Pembina and Value Optimization Areas.

The Pembina area comprises Sinopec Daylight's Brazeau and Warburg properties, as well as a number of minor properties.

The Brazeau property is located approximately 145 kilometers southwest of Edmonton, Alberta near the community of Drayton Valley. Sinopec Daylight operates three significant facilities for the processing of sour oil and the compression of gas in the Brazeau area. The gas is shipped for final processing at the neighboring Brazeau River Complex with the option to flow to other processing plants in the area.

The Warburg and Tomahawk properties are located approximately 30 kilometers east of Drayton Valley. Sinopec Daylight operates two significant facilities for the processing of sour oil and the compression of sour gas in addition to a number of sweet oil facilities in the Warburg/Tomahawk area. The sour gas is shipped for final processing at Minnehik-Buck Lake.

The majority of reserves in the Pembina area are associated with the Cardium, Rock Creek, Nisku, and Belly River formations with additional reserves assigned to the Ellerslie, Notikewan, and various other cretaceous zones. Proved plus probable reserves in the McDaniel Report total 51 MMboe for our interests in this area at year end 2016.

The Value Optimization properties are primarily located approximately 230 kilometers northwest of Edmonton, Alberta. The West Central area contains six significant sub-properties: Obed, Pine Creek, Marlboro, Medicine Lodge, Kaybob, and Cecil and a number of minor properties. Historically, the major producing formations in the West Central area were the prolific gas-charged Wabamun and Leduc reservoirs. In recent years, attention has focused on the shallower Notikewin, Bluesky, Gething and Wilrich zones.

Proved plus probable reserves in the McDaniel Report total 27 MMboe to our interests in this area at year end 2016.

Deep Basin Business Unit

The Deep Basin area consists of Sinopec Daylight's Peace River Arch ("PRA") properties. The PRA properties are located in proximity to the City of Grande Prairie, in northwest Alberta. The PRA area contains three significant sub-properties: Wapiti, Elmworth, and Karr and a number of minor properties. In Wapiti, development and production is primarily from the Montney formation, which is being developed with horizontal wells. In Elmworth, reserves are developed with both vertical and horizontal gas wells and production is commingled from the Cadotte, Falher, Bluesky, Gething, Cadomin, and Nikanassin formations. Sinopec Daylight has identified numerous additional Montney, and Cadomin horizontal well opportunities in the PRA area. McDaniel has assigned total proved plus probable reserves of 199 MMboe to our interest in this area at year end 2016.

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2016. Although many wells produce both oil and natural gas, a well is categorized as an oil well or a natural gas well based upon the proportion of oil or natural gas production that constitutes the majority of production from that well.

Number and Status of Wells	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross[1]	Net	Gross[1]	Net	Gross[1]	Net	Gross[1]	Net
Alberta	449	353	196	155	657	309	357	216
British Columbia	23	1	17	2	59	4	46	3
Saskatchewan	1	1	0	0	0	0	0	0
Total	473	355	213	157	716	313	403	219

(1) Gross wells include unit wells

Properties with no Attributed Reserves

The following table sets out our undeveloped land holdings as at December 31, 2016. Our undeveloped land holdings have no reserves attributed to them.

Undeveloped Land Holdings	Undeveloped Acres	
	Gross	Net
Alberta	650,934	489,185
British Columbia	21,987	9,710
Saskatchewan	14,723	7,362
Total	687,644	506,256

We expect that rights to explore, develop and exploit 150,000 net acres of our undeveloped land holdings will be subject to potential expiry within one year. We have no material work commitments on such properties. Where we determine appropriate, we may continue expiring leases by either making the necessary applications to extend or by performing the necessary work. Sinopec Daylight calculates gross undeveloped acres by including undrilled spacing units in each lease or license where we have a working interest. The net undeveloped acreage is calculated by multiplying the gross acreage by our working interest percentage.

There are several economic factors and significant uncertainties that affect the anticipated development of Sinopec Daylight's properties with no attributed reserves. Sinopec Daylight will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil and natural gas from these properties in the future.