Sinopec Daylight Energy Ltd.

2013 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 Sproule Associates Limited ("Sproule") with an effective date of December 31, 2013 contained in the Sproule reserve report ("Sproule Report") dated January 13, 2014. The opening reserves balances represent the reserves for Sinopec Daylight at December 31, 2012. 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 Sproule 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 Sproule 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, 2013, 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 Sproule 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**		**Shale Oil**	
	Gross *(MBbl)*	**Net** *(MBbl)*	**Gross** *(MBbl)*	**Net** *(MBbl)*	**Gross** *(MBbl)*	**Net** *(MBbl)*
Proved						
Developed producing	14,287	11,899	118	106	33	32
Developed non-producing	1,639	1,061	-	-	-	-
Undeveloped	8,215	6,965	-	-	-	-
Total Proved	24,141	19,925	118	106	33	32
Probable	16,937	13,213	179	157	21	20
Total proved plus probable	**41,078**	**33,138**	**297**	**263**	**54**	**52**

Reserves	**Natural Gas**		**Coalbed Methane**		**Shale Gas**	
	Gross *(MMcf)*	**Net** *(MMcf)*	**Gross** *(MMcf)*	**Net** *(MMcf)*	**Gross** *(MMcf)*	**Net** *(MMcf)*
Proved						
Developed producing	189,495	169,679	409	392	620	578
Developed non-producing	23,604	20,918	258	245	-	-
Undeveloped	303,996	282,236	774	735	-	-
Total Proved	517,096	472,832	1,441	1,372	620	578
Probable	460,629	413,744	1,279	1,216	8,908	8,153
Total proved plus probable	**977,725**	**886,576**	**2,720**	**2,588**	**9,528**	**8,731**

Reserves	Natural Gas Liquids		Total	
	Gross	Net	Gross	Net
	(MBbl)	*(MBbl)*	*(Mboe)*	*(Mboe)*
Proved				
Developed producing	8,215	5,950	54,407	46,428
Developed non-producing	872	648	6,488	5,236
Undeveloped	13,568	10,932	72,577	65,059
Total Proved	22,654	17,530	133,472	116,723
Probable	17,098	12,443	112,705	96,351
Total proved plus probable	**39,752**	**29,973**	**246,177**	**213,074**

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

(000s) discounted at	0%	5%	10%	15%	20%
Proved					
Developed producing	$1,416,417	$1,127,310	$942,841	$816,635	$725,222
Developed non-producing	$149,565	$125,585	$108,043	$94,584	$83,920
Undeveloped	$809,602	$441,254	$217,463	$73,985	($21,848)
Total Proved	$2,375,584	$1,694,150	$1,268,348	$985,205	$787,293
Probable	$2,228,031	$1,200,068	$712,262	$445,198	$284,051
Total proved plus probable	**$4,603,615**	**$2,894,218**	**$1,980,610**	**$1,430,404**	**$1,071,344**

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

(000s) discounted at	0%	5%	10%	15%	20%
Proved					
Developed producing	$1,416,417	$1,127,310	$942,841	$816,635	$725,222
Developed non-producing	$149,565	$125,585	$108,043	$94,584	$83,920
Undeveloped	$809,602	$441,254	$217,463	$73,985	($21,848)
Total Proved	$2,375,584	$1,694,150	$1,268,348	$985,205	$787,293
Probable	$1,737,395	$955,958	$578,742	$367,097	$236,008
Total proved plus probable	**$4,112,979**	**$2,650,108**	**$1,847,090**	**$1,352,302**	**$1,023,301**

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	$3,083,890	$436,893	$1,198,765	$1,110	$30,704	$1,416,417	-	$1,416,417
Developed non-producing	$343,498	$73,907	$100,369	$18,573	$1,084	$149,565	-	$149,565
Undeveloped	$3,542,012	$361,692	$1,181,689	$1,175,014	$14,014	$809,602	-	$809,602
Total Proved	$6,969,400	$872,492	$2,480,824	$1,194,697	$45,802	$2,375,584	-	$2,375,584
Probable	$6,082,305	$876,049	$2,167,611	$795,817	$14,797	$2,228,031	$490,637	$1,737,395
Total proved plus probable	**$13,051,704**	**$1,748,541**	**$4,648,435**	**$1,990,514**	**$60,598**	**$4,603,615**	**$490,637**	**$4,112,979**

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]	$703,159	$26.80
Heavy oil[1]	$3,587	$27.91
Shale Oil	$1,757	$38.32
Natural gas[2] (Non Assoc. & Assoc.)	$553,335	$6.16
Coalbed methane	$340	$1.49
Shale Gas	$6,755	$28.68
Other Revenue	($586)	N/A
Total Proved	**$1,268,348**	**$10.87**
Proved plus probable		
Light and medium crude oil[1]	$984,675	$23.51
Heavy oil[1]	$6,189	$17.13
Shale Oil	$2,717	$37.78
Natural gas[2] (Non Assoc. & Assoc.)	$1,017,213	$6.10
Coalbed methane	$548	$1.27
Shale Gas	$1,432	$0.41
Other Revenue	($32,164)	N/A
Total Proved plus probable	**$1,980,610**	**$9.30**

(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 2.0% per year together with the following price forecasts supplied by Sproule.

Year	West Texas Intermediate Crude Oil *($US/Bbl)*	Edmonton par Crude Oil *($Cdn/Bbl)*	Natural Gas At AECO *($Cdn/MMbtu)*	Foreign Exchange *($US/$Cdn)*
2014	$93.80	$96.00	$3.40	$0.977
2015	$88.31	$90.38	$3.61	$0.977
2016	$85.49	$87.50	$3.79	$0.977
2017	$96.96	$99.23	$4.81	$0.977
2018	$98.41	$100.72	$4.89	$0.977
2019	$99.89	$102.23	$4.97	$0.977
2020	$101.38	$103.76	$5.05	$0.977
2021	$102.91	$105.32	$5.13	$0.977
2022	$104.45	$106.90	$5.22	$0.977
2023	$106.02	$108.50	$5.30	$0.977
2024 Escalation of 1.5% thereafter	$107.61	$110.13	$5.39	$0.977

Weighted average historical prices realized by Sinopec Daylight for the year ended December 31, 2013 were $3.25 per Mcf for natural gas, $88.88 per Bbl for light oil and $58.00 per Bbl for NGLs.

Reserves Reconciliation

Reconciliation of Gross Reserves

	Light and Medium Oil			Heavy Oil		
	Proved (MBbl)	Probable (MBbl)	Proved plus Probable (MBbl)	Proved (MBbl)	Probable (MBbl)	Proved plus Probable (MBbl)
December 31, 2012	26,135	14,589	40,724	353	135	488
Extensions and improved recovery	159	1,992	2,152	-	-	-
Infill Drilling	3,579	1,167	4,745	-	-	-
Technical revisions	(2,403)	(854)	(3,257)	(150)	(49)	(101)
Discoveries	136	100	236	-	-	-
Acquisitions	8	(3)	5	-	-	-
Dispositions	-	-	-	-	-	-
Expired Leases	-	-	-	-	-	-
Economic factors	(106)	(54)	(160)	(36)	(5)	(41)
Production	(3,367)	-	(3,367)	(50)	-	(50)
December 31, 2013	**24,141**	**16,937**	**41,078**	**118**	**179**	**297**

Reconciliation of Gross Reserves

	Shale Oil			Natural Gas Liquids		
	Proved (MBbl)	Probable (MBbl)	Proved plus Probable (MBbl)	Proved (MBbl)	Probable (MBbl)	Proved plus Probable (MBbl)
December 31, 2012	-	-	-	16,344	12,727	29,071
Extensions and improved recovery	-	-	-	1,305	238	1,543
Infill Drilling	-	-	-	1,945	1,434	3,378
Technical revisions	-	-	-	3,863	1,805	5,668
Discoveries	99	21	121	48	30	78
Acquisitions	-	-	-	2,048	1,217	3,265
Dispositions	-	-	-	-	-	-
Expired Leases	-	-	-	(78)	(221)	(299)
Economic factors	-	-	-	(298)	(130)	(428)
Production	(66)	-	(66)	(2,523)	-	(2,523)
December 31, 2013	**33**	**21**	**55**	**22,654**	**17,098**	**39,752**

Reconciliation of Gross Reserves	Associated and Non-Associated Gas			Shale Gas		
	Proved (MMcf)	Probable (MMcf)	Proved plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved plus Probable (MMcf)
December 31, 2012	464,632	445,311	909,943	-	-	-
Extensions and improved recovery	28,248	(4,476)	23,772	-	8,415	8,415
Infill Drilling	26,366	32,026	58,392	-	-	-
Technical revisions	23,800	(12,644)	11,156	-	-	-
Discoveries	104	28	132	707	493	1,200
Acquisitions	40,881	24,285	65,165	-	-	-
Dispositions	-	-	-	-	-	-
Expired Leases	(4,489)	(19,040)	(23,529)	-	-	-
Economic factors	(9,574)	(4,860)	(14,434)	-	-	-
Production	(52,872)	-	(52,872)	(88)	-	(88)
December 31, 2013	**517,095**	**460,629**	**977,724**	**620**	**8,908**	**9,528**

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, 2012	617	1,730	2,347	120,373	101,958	222,331
Extensions and improved recovery	-	-	-	6,172	2,887	9,059
Infill Drilling	-	-	-	9,918	7,938	17,855
Technical revisions	1,781	(1,129)	652	5,574	(1,295)	4,279
Discoveries	-	-	-	419	238	657
Acquisitions	-	-	-	8,870	5,261	14,130
Dispositions	-	-	-	-	-	-
Expired Leases	-	-	-	(826)	(3,395)	(4,221)
Economic factors	(838)	678	(160)	(2,175)	(886)	(3,061)
Production	(119)	-	(119)	(14,852)	-	(14,852)
December 31, 2013	**1,441**	**1,279**	**2,720**	**133,472**	**112,705**	**246,177**

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule 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.

Nearly all of our proved undeveloped reserves fall within the following categories:

- wells budgeted and scheduled to be drilled from 2014 to 2018;
- wells drilled which require completion or have been completed and require equipping and tie-in during 2014 or 2015; and

- secondary zones that will be completed for production once the primary zone is depleted.

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 23% of our probable reserves are attributed to better performance of reserves from producing wells. The remaining 77% 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, 2013, $610 million was spent on capital expenditures including land and property acquisitions, net of dispositions. A portion of the 2014 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**		**Shale 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)*
2010	6,356	6,924	-	83	-	-
2011	3,068	7,144	-	83	-	-
2012	2,861	9,707	-	72	-	-
2013	455	8,215	-	-	-	-

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)
2010	61,702	145,555	-	-	1,304	2,398
2011	35,029	138,001	-	-	969	3,157
2012	22,360	235,154	-	-	1,170	8,296
2013	76,646	304,769	-	-	4,336	13,578

Proved Undeveloped Reserves	Oil Equivalent	
	First Attributed (Mboe)	Total at Year-end (Mboe)
2010	17,944	33,664
2011	9,875	33,384
2012	7,758	57,267
2013	17,555	72,588

Approximately 67% of Sinopec Daylight's future capital associated with proved undeveloped reserves is scheduled for expenditure in 2014 and 2015. The major areas of development in 2014 and 2015 are the Brazeau, Warburg, Tomahawk, and Wapiti properties. The proved undeveloped reserves scheduled for development in 2014 and 2015 represent 58% of the total proved undeveloped reserves. The remaining proved undeveloped capital and reserves are primarily associated with the Chigwell, Elmworth, Oldman, Marlboro, Medicine Lodge and Pine Creek 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		Shale 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)*
2010	5,371	6,712	-	81	-	-
2011	4,130	8,478	-	81	-	-
2012	2,186	8,161	-	81	-	-
2013	437	8,097	-	95	-	-

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)*
2010	125,646	251,143	-	-	2,273	4,976
2011	71,178	288,042	-	-	2,744	6,820
2012	43,652	342,364	-	-	1,536	8,980
2013	57,293	367,468	8,415	8,415	2,630	12,808

Probable Undeveloped Reserves	Oil Equivalent	
	First Attributed *(Mboe)*	Total at Year-end *(Mboe)*
2010	28,585	53,626
2011	18,737	63,386
2012	10,997	74,283
2013	13,624	83,647

Approximately 63% of Sinopec Daylight's future capital associated with probable undeveloped reserves is scheduled for expenditure in 2014 and 2015. The major areas of development in 2014 and 2015 are the Brazeau, Elmworth, Medicine Lodge, Tomahawk and Wapiti properties. The probable undeveloped reserves scheduled for development in 2014 and 2015 represent 49% of the total probable undeveloped reserves. The remaining probable undeveloped capital and reserves are primarily associated with the Kaybob, Marlboro and Obed 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 Sproule, 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**
2014	$ 485,627	$ 735,202
2015	320,527	522,920
2016	203,855	253,626
2017	116,797	211,984
2018	55,270	144,361
Remaining	12,621	122,421
Total	**$1,194,697**	**$1,990,514**

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, 2013. Reserve amounts are stated, before deduction of royalties as at December 31, 2013, based on forecast cost and price assumptions as evaluated in the Sproule 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 Area

The Greater Pembina area consists of Sinopec Daylight's Brazeau and Warburg properties. The Brazeau property is located approximately 145 kilometers southwest of Edmonton, Alberta near the community of Drayton Valley. Sinopec Daylight operates two significant facilities for the processing of sour oil and the compression of sour gas in the Brazeau area. The sour gas is shipped for final processing at four third-party midstream plants located in the neighboring Brazeau River and West Pembina areas. The majority of reserves are associated with the Cardium and Nisku formations with additional reserves assigned to the Rock Creek, Ellerslie and Notikewan zones. Significant development of the Cardium zone with horizontal wells occurred during 2013 and is expected to continue in 2014. Proved plus probable reserves in the Sproule Report total 44.7 MMboe for our interests in this area at year end 2013.

The Warburg properties are located to the east of the Brazeau property, approximately 30 kilometers east of Drayton Valley. The Warburg area contains five significant sub-properties: Easyford, Tomahawk, Warburg, Chip Lake and Caroline and a number of minor properties. Sinopec Daylight operates two significant facilities for the processing of sour oil and the compression of sour gas and a number of sweet oil facilities in the Warburg area. The sour gas is shipped for final processing at two third-party midstream plants located in the neighboring Bigoray and Minnehik-Buck Lake areas. The majority of reserves are associated with the Cardium, Nisku, and Belly River formations with additional reserves assigned to the Ellerslie and various other cretaceous zones. Significant development of the Cardium and Belly River zones with horizontal wells occurred during 2013 and is expected to continue in 2014. Proved plus probable reserves in the Sproule Report total 23.9 MMboe for our interests in this area at year end 2013.

Deep Basin Area

The Deep Basin area consists of Sinopec Daylight's Peace River Arch ("PRA") and "Value Optimization" 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: Elmworth, Wapiti, and Karr and a number of minor properties. 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. In Wapiti, development and production is primarily from the Montney formation, which is being developed with horizontal wells. Sinopec Daylight has identified numerous additional Montney, Cadomin and Nikanassin horizontal well opportunities in the PRA area. Sproule has assigned total proved plus probable reserves of 140.9 MMboe to our interest in this area at year end 2013.

The Value Optimization (Value Opt.) 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. During 2013, development of the Bluesky, Cardium and Wilrich zones with multi-staged stimulated horizontal wells was undertaken with strong results. During 2014, horizontal well development of the Bluesky and Wilrich formations is expected to continue. Sproule has assigned total proved plus probable reserves of 36.7 MMboe to our interests in this area at year end 2013.

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, 2013. 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	466	375	206	165	942	493	341	216
British Columbia	4	1	5	2	15	6	2	1
Saskatchewan	1	1	0	0	0	0	0	0
Total	471	377	211	167	957	499	343	217

(1) Gross wells include unit wells

Properties with no Attributed Reserves

The following table sets out our undeveloped land holdings as at December 31, 2013. Our undeveloped land holdings have no reserves attributed to them.

Undeveloped Land Holdings	**Undeveloped Acres**	
	Gross	**Net**
Alberta	1,026,676	870,102
British Columbia	63,009	44,569
Saskatchewan	14,896	7,448
Total	1,104,581	922,119

We expect that rights to explore, develop and exploit 147,174 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.