SUNCOR ENERGY INC.

ANNUAL INFORMATION FORM

Dated February 25, 2016

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

The Statement of Reserves Data and Other Oil and Gas Information outlined below is dated February 25, 2016, with an effective date of December 31, 2015. Reserves evaluations have not been updated since the effective date and, thus, do not reflect changes in our reserves since that date. The preparation date of the information is February 19, 2016.

Disclosure of Reserves Data

Suncor is subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of reserves data in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* (NI 51-101).

The reserves data included in this section of the AIF for Suncor's Mining and In Situ operations is based upon evaluations conducted by GLJ Petroleum Consultants Ltd. (GLJ), contained in their reports (the GLJ Reports). The reserves data set forth below for all other reserves, which includes Suncor's interests in its conventional assets offshore Newfoundland and Labrador and its natural gas assets located in Western Canada (collectively, E&P Canada), and conventional assets offshore the U.K. (North Sea) and in Libya (Other International), is based upon evaluations conducted by Sproule Associates Limited or Sproule International Limited (collectively, Sproule), contained in their reports (the Sproule Reports). Each of GLJ and Sproule (collectively, the Evaluators) are independent qualified reserves evaluators as defined in NI 51-101.

The reserves data summarizes Suncor's SCO, bitumen, light crude oil and medium crude oil combined, heavy crude oil, conventional natural gas and NGLs reserves and the net present values of future net revenues for these reserves using forecast prices and costs prior to provision for interest and general and administrative expense.

Advisories – Future Net Revenues

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. There is no guarantee that the estimates for SCO, bitumen, light crude oil and medium crude oil, heavy crude oil, conventional natural gas and NGLs reserves provided herein will be recovered. Actual SCO, bitumen, light crude oil and medium crude oil, heavy crude oil, conventional natural gas and NGLs volumes recovered may be greater than or less than the estimates provided herein. Readers should review the Glossary of Terms and Abbreviations, the definitions and information contained in the Notes to Reserves Data Tables, Definitions for Reserves Data Tables and Notes to Future Net Revenues Tables discussion in conjunction with the following notes and tables.

Significant Risk Factors and Uncertainties Affecting Reserves

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 as a result of newly acquired technical data, technology improvements, or changes in historical performance, pricing, economic conditions, market availability, and regulatory requirements. Additional technical information regarding geology, reservoir properties and reservoir fluid properties is obtained through seismic programs, drilling programs, updated reservoir performance studies and analysis, and production history, and may result in revisions to reserves. Pricing, market availability and economic conditions affect the profitability of reserves development. For example, higher commodity prices may result in higher reserves by making more projects economically viable or extending their economic life, while lower commodity prices, may result in lower reserves (however, this is generally not the case for assets under PSCs, as described in the Notes to Reserves Data Tables in relation to the economic interest method used to determine entitlement reserves). Royalty regimes and environmental regulations and other regulatory changes cannot be predicted but may have positive or negative effects on reserves. Future technology improvements would be expected to have a favourable impact on the economics of reserves development and exploitation, and therefore may result in an increase to reserves. Should political unrest continue in Libya, this may result in unfavourable changes to Suncor's reserves in that country.

While the above factors, and many others, are relevant, certain judgments and assumptions are always required. As new information becomes available, these areas are reviewed and revised accordingly.

The reserves included in this AIF represent estimates only. There are numerous uncertainties inherent in estimating quantities and quality of these reserves, including many factors beyond our control. In general, estimates of economically recoverable reserves and the future net cash flow from these assets are based upon a number of variable factors and assumptions, such as production forecasts, regulations, pricing, the timing and amount of capital expenditures, future royalties, future operating costs, and yield rates for upgraded production of synthetic crude oil from bitumen – all of which may vary considerably from actual results and may be affected by many of the factors identified under Industry Conditions and Risk Factors herein. The accuracy of any reserves estimate is a matter of interpretation and judgment and is a function of the quality and quantity of available data, which may have been gathered over time. For these reasons, estimates of the economically recoverable reserves and classification of such reserves based on the certainty of recovery, prepared by different engineers or by the same engineers at different times, may vary.

Reserves estimates are based upon geological assessment, including drilling and laboratory tests. Mining reserves estimates also consider production capacity and upgrading yields, mine plans, operating life and regulatory constraints. In Situ reserves and estimates are also based upon the testing of core samples and seismic operations and demonstrated commercial success of in situ processes. Our actual production, revenues, royalties, taxes, and development and operating expenditures with respect to our reserves will vary from such estimates, and such variances could be material. Production performance subsequent to the date of the estimate may justify revision, either upward or downward, if material.

The reserves evaluations are based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated cash flow to be derived from the reserves contained in the reserves evaluations may be increased or reduced to the extent that such activities do or do not achieve the level of success assumed in the reserves evaluations.

Oil and Gas Reserves Tables and Notes

Summary of Oil and Gas Reserves[1][2][3]

as at December 31, 2015
(forecast prices and costs)

	SCO[4] (mmbbls)		Bitumen (mmbbls)		Light Crude & Medium Crude Oil (mmbbls)		Conventional Natural Gas[5][6] (bcfe)		Total[7] (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Developed Producing										
Mining	1 673	1 498	—	—	—	—	—	—	1 673	1 498
In Situ	186	179	122	117	—	—	—	—	308	296
E&P Canada	—	—	—	—	56	44	32	29	61	49
Total Canada	1 859	1 678	122	117	56	44	32	29	2 043	1 843
North Sea	—	—	—	—	58	58	3	3	58	58
Other International	—	—	—	—	—	—	—	—		
Total Proved Developed Producing	**1 859**	**1 678**	**122**	**117**	**114**	**101**	**35**	**32**	**2 101**	**1 901**
Proved Developed Non-Producing										
Mining	—	—	—	—	—	—	—	—	—	—
In Situ	—	—	3	3	—	—	—	—	3	3
E&P Canada	—	—	—	—	—	—	2	2	—	—
Total Canada	—	—	3	3	—	—	2	2	3	3
North Sea	—	—	—	—	—	—	—	—	—	—
Other International	—	—	—	—	87	27	—	—	87	27
Total Proved Developed Non-Producing	**—**	**—**	**3**	**3**	**87**	**27**	**2**	**2**	**90**	**29**
Proved Undeveloped										
Mining	—	—	1 052	943	—	—	—	—	1 052	943
In Situ	584	494	741	629	—	—	—	—	1 324	1 124
E&P Canada	—	—	—	—	22	19	—	—	51	48
Total Canada	584	494	1 792	1 572	22	19	—	—	2 427	2 115
North Sea	—	—	—	—	10	10	1	1	10	10
Other International	—	—	—	—	51	13	—	—	51	13
Total Proved Undeveloped	**584**	**494**	**1 792**	**1 572**	**82**	**42**	**1**	**1**	**2 488**	**2 138**
Proved										
Mining	1 673	1 498	1 052	943	—	—	—	—	2 725	2 441
In Situ	769	673	866	749	—	—	—	—	1 634	1 422
E&P Canada	—	—	—	—	78	63	34	30	113	97
Total Canada	2 442	2 171	1 917	1 692	78	63	34	30	4 473	3 961
North Sea	—	—	—	—	67	67	4	4	68	68
Other International	—	—	—	—	138	40	—	—	138	40
Total Proved	**2 442**	**2 171**	**1 917**	**1 692**	**283**	**171**	**38**	**34**	**4 679**	**4 069**
Probable										
Mining	494	429	542	461	—	—	—	—	1 035	890
In Situ	1 257	1 020	305	241	—	—	—	—	1 561	1 260
E&P Canada	—	—	—	—	129	98	13	11	213	171
Total Canada	1 750	1 448	846	702	129	98	13	11	2 810	2 321
North Sea	—	—	—	—	26	26	2	2	26	26
Other International	—	—	—	—	95	38	—	—	95	38
Total Probable	1 750	1 448	846	702	251	161	15	13	2 931	2 385
Proved Plus Probable										
Mining	2 167	1 927	1 593	1 404	—	—	—	—	3 760	3 331
In Situ	2 025	1 692	1 170	990	—	—	—	—	3 196	2 683
E&P Canada	—	—	—	—	207	161	47	42	326	268
Total Canada	4 192	3 619	2 764	2 394	207	161	47	42	7 282	6 281
North Sea	—	—	—	—	94	94	6	6	94	94
Other International	—	—	—	—	233	78	—	—	233	78
Total Proved Plus Probable	**4 192**	**3 619**	**2 764**	**2 394**	**534**	**332**	**53**	**47**	**7 610**	**6 454**

Please see Notes (1) through (7) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Reserves[1][2][3]
as at December 31, 2015
(forecast prices and costs)

	SCO[4]			Bitumen			Light Crude & Medium Crude Oil			Conventional Natural Gas[5][6]			Total[7]		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcfe	bcfe	bcfe	mmboe	mmboe	mmboe
Mining															
December 31, 2014	1 792	498	2 291	845	408	1 253	—	—	—	—	—	—	2 637	907	3 543
Extensions & Improved Recovery[8]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions[9]	(23)	(5)	(27)	—	27	27	—	—	—	—	—	—	(23)	22	—
Discoveries[10]	—	—	—	—	—	—	—	—	—	—	—	—	—		—
Acquisitions	—	—	—	207	107	314	—	—	—	—	—	—	207	107	314
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production	(96)	—	(96)	—	—	—	—	—	—	—	—	—	(96)	—	(96)
December 31, 2015	**1 673**	**494**	**2 167**	**1 052**	**542**	**1 593**	**—**	**—**	**—**	**—**	**—**	**—**	**2 725**	**1 035**	**3 760**
In Situ															
December 31, 2014	698	1 156	1 854	994	328	1 322	—	—	—	—	—	—	1 692	1 485	3 177
Extensions & Improved Recovery[8]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions[9]	100	101	201	(86)	(24)	(110)	—	—	—	—	—	—	14	77	91
Discoveries[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[11]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Production	(30)	—	(30)	(42)	—	(42)	—	—	—	—	—	—	(72)	—	(72)
December 31, 2015	**769**	**1 257**	**2 025**	**866**	**305**	**1 170**	**—**	**—**	**—**	**—**	**—**	**—**	**1 634**	**1 561**	**3 196**
E&P Canada															
December 31, 2014	—	—	—	—	—	—	110	230	340	50	18	68	119	233	351
Extensions & Improved Recovery[8]	—	—	—	—	—	—	—	5	5	—	—	—	—	5	5
Technical Revisions[9]	—	—	—	—	—	—	(15)	(106)	(121)	(1)	(3)	(4)	14	(25)	(11)
Discoveries[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[11]	—	—	—	—	—	—	—	—	—	(8)	(2)	(10)	(1)	—	(2)
Production	—	—	—	—	—	—	(17)	—	(17)	(7)	—	(7)	(18)	—	(18)
December 31, 2015	**—**	**—**	**—**	**—**	**—**	**—**	**78**	**129**	**207**	**34**	**13**	**47**	**113**	**213**	**326**
Total Canada															
December 31, 2014	2 491	1 655	4 145	1 838	737	2 575	110	230	340	50	18	68	4 447	2 624	7 071
Extensions & Improved Recovery[8]	—	—	—	—	—	—	—	5	5	—	—	—	—	5	5
Technical Revisions[9]	78	96	174	(86)	3	(83)	(15)	(106)	(121)	(1)	(3)	(4)	6	74	80
Discoveries[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	207	107	314	—	—	—	—	—	—	207	107	314
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[11]	—	—	—	—	—	—	—	—	—	(8)	(2)	(10)	(1)	—	(2)
Production	(126)	—	(126)	(42)	—	(42)	(17)	—	(17)	(7)	—	(7)	(186)	—	(186)
December 31, 2015	**2 442**	**1 750**	**4 192**	**1 917**	**846**	**2 764**	**78**	**129**	**207**	**34**	**13**	**47**	**4 473**	**2 810**	**7 282**

Please see Notes (1) through (11) at the end of the reserves data section for important information about volumes in this table.

Reconciliation of Gross Reserves[1][2][3] *(continued)*

as at December 31, 2015
(forecast prices and costs)

	SCO[4]			Bitumen			Light Crude & Medium Crude Oil			Conventional Natural Gas[5][6]			Total[7]		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	mmbbls	bcfe	bcfe	bcfe	mmboe	mmboe	mmboe
North Sea															
December 31, 2014	—	—	—	—	—	—	91	37	128	3	2	5	91	38	129
Extensions & Improved Recovery[8]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions[9]	—	—	—	—	—	—	1	(12)	(10)	4	—	4	2	(12)	(10)
Discoveries[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[11]	—	—	—	—	—	—	(2)	1	(1)	—	—	—	(2)	1	(1)
Production	—	—	—	—	—	—	(23)	—	(23)	(4)	—	(4)	(24)	—	(24)
December 31, 2015	**—**	**—**	**—**	**—**	**—**	**—**	**67**	**26**	**94**	**4**	**2**	**6**	**68**	**26**	**94**
Other International															
December 31, 2014	—	—	—	—	—	—	142	111	253	—	—	—	142	111	253
Extensions & Improved Recovery[8]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Technical Revisions[9]	—	—	—	—	—	—	(1)	(17)	(18)	—	—	—	(1)	(17)	(18)
Discoveries[10]	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[11]	—	—	—	—	—	—	(2)	1	(1)	—	—	—	(2)	1	(1)
Production	—	—	—	—	—	—	(1)	—	(1)	—	—	—	(1)	—	(1)
December 31, 2015	**—**	**—**	**—**	**—**	**—**	**—**	**138**	**95**	**233**	**—**	**—**	**—**	**138**	**95**	**233**
Total															
December 31, 2014	2 491	1 655	4 145	1 838	737	2 575	343	378	721	53	20	73	4 681	2 773	7 454
Extensions & Improved Recovery[8]	—	—	—	—	—	—	—	5	5	—	—	—	—	5	5
Technical Revisions[9]	78	96	174	(86)	3	(83)	(15)	(135)	(150)	3	(3)	1	7	45	52
Discoveries[10]	—	—	—	—	—	—	—	—	—	—	—	—	—		
Acquisitions	—	—	—	207	107	314	—	—	—	—	—	—	207	107	314
Dispositions	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Economic Factors[11]	—	—	—	—	—	—	(4)	2	(2)	(8)	(2)	(10)	(5)	1	(4)
Production	(126)	—	(126)	(42)	—	(42)	(41)	—	(41)	(11)	—	(11)	(211)	—	(211)
December 31, 2015	**2 442**	**1 750**	**4 192**	**1 917**	**846**	**2 764**	**283**	**251**	**534**	**38**	**15**	**53**	**4 679**	**2 931**	**7 610**

Please see Notes (1) through (11) at the end of the reserves data section for important information about volumes in this table.

Notes to Reserves Data Tables

as at December 31, 2015

(1) See the Notes to Future Net Revenues Tables discussion for information on forecast prices and costs.

(2) Reserves data tables may not add due to rounding.

(3) Other International is comprised of quantities of crude oil in Libya which are expected to be produced under EPSAs. Under these EPSAs, net proved and probable reserves have been determined using the economic interest method. See the Reserves Categories section for a description of the economic interest method.

(4) SCO reserves figures include the company's diesel sales volumes.

(5) All conventional natural gas, other than immaterial amounts of NGLs (0.4 mmbbls of total proved and 0.6 mmbbls of total proved plus probable NGLs).

(6) Despite a change in the NI 51-101 definition of Natural Gas, natural gas volumes have been reconciled as the associated assets are the same as previously reported.

(7) Total gross volumes for E&P Canada include quantities of heavy crude oil as follows: Proved Undeveloped of 30 mmbbls, Proved of 30 mmbbls, Probable of 82 mmbbls and Proved Plus Probable of 111 mmbbls. Total net volumes for E&P Canada include quantities of heavy crude oil as follows: Proved Undeveloped of 29 mmbbls, Proved of 29 mmbbls, Probable of 71 mmbbls and Proved Plus Probable of 100 mmbbls. For the year ended December 31, 2014, Suncor had no reserves reportable for Heavy Oil. For the year ended December 31, 2015, and for the purposes of the reconciliation, all reserves added in the Heavy Oil category were the result of Technical Revisions.

(8) Extensions & Improved Recovery are additions to the reserves resulting from step-out drilling, infill drilling and implementation of improved recovery schemes. Negative volumes, if any, for probable reserves result from the transfer of probable reserves to proved reserves.

(9) Technical Revisions include changes in previous estimates resulting from new technical data or revised interpretations. In the case of In Situ, a decrease in probable bitumen reserves and an increase in SCO reserves is a result of a planned increase in upgraded Firebag volumes over the forecast period.

(10) Discoveries are additions to reserves in reservoirs where no reserves were previously booked.

(11) Economic Factors are changes due primarily to price forecasts, inflation rates or regulatory changes.

Definitions for Reserves Data Tables

In the tables set forth above and elsewhere in this AIF, the following definitions and other notes are applicable:

Gross means:

(a) in relation to Suncor's interest in production or reserves, Suncor's working-interest share before deduction of royalties and without including any royalty interests of Suncor;

(b) in relation to wells, the total number of wells in which Suncor has a working interest; and

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

Net means:

(a) in relation to Suncor's interest in production or reserves, Suncor's working-interest share after deduction of royalty obligations, plus the company's royalty interests in production and reserves;

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

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

Reserves Categories

The reserves estimates presented are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation (COGE) Handbook. A summary of those definitions is set forth below.

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on analyses of drilling, geological, geophysical and engineering data, the use of established technology, and specified economic conditions, which are generally accepted as being reasonable.

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

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Proved reserves estimates should target at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

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. That is, proved plus probable reserves estimates should target at least a 50% probability that the quantities actually recovered will equal or exceed the estimate.

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

Proved and probable reserves categories may be divided into developed and undeveloped categories:

Developed reserves are those reserves that are expected to be recovered (i) from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production, or (ii) through installed extraction equipment and infrastructure that is operational at the time of the reserves estimate, if the extraction is by means not involving a well. The developed category may be subdivided into producing and non-producing.

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

(b) 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.

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

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

In the **economic interest method** used for PSCs, Suncor's share of profit revenue plus cost recovery revenue is divided by the associated oil or gas price forecast to determine Suncor's net volume entitlement, or **entitlement reserves**. The entitlement reserves are then adjusted to include reserves relating to income taxes payable by the national oil company on behalf of Suncor. Under this method, reported reserves will increase as commodity prices decrease (and vice versa).

Future Net Revenues Tables and Notes(1)

Net Present Value of Future Net Revenues Before Income Taxes
as at December 31, 2015
(forecast prices and costs)

	(in $ millions, discounted at % per year)					Unit Value(2)
	0%	5%	10%	15%	20%	($/boe)
Proved Developed Producing						
Mining	19 220	15 149	9 715	6 233	4 078	6.48
In Situ	6 317	5 602	4 999	4 495	4 072	16.87
E&P Canada	782	919	952	940	909	19.67
Total Canada	26 318	21 670	15 666	11 668	9 060	8.50
North Sea	1 962	1 887	1 782	1 672	1 568	30.68
Other International	—	—	—	—	—	—
Total Proved Developed Producing	28 280	23 557	17 448	13 340	10 628	9.18
Proved Developed Non-Producing						
Mining	—	—	—	—	—	—
In Situ	59	65	67	67	66	31.58
E&P Canada	2	2	1	1	1	4.84
Total Canada	61	67	68	68	67	28.35
North Sea	—	—	—	—	—	—
Other International	1 224	879	660	514	412	24.44
Total Proved Developed Non-Producing	1 285	946	729	582	479	24.76
Proved Undeveloped						
Mining	15 152	4 185	388	(1 157)	(1 867)	0.41
In Situ	32 294	16 549	9 132	5 317	3 202	8.13
E&P Canada	1 102	623	288	56	(104)	5.95
Total Canada	48 548	21 357	9 808	4 216	1 230	4.64
North Sea	217	175	142	115	93	14.23
Other International	220	51	(37)	(83)	(105)	(2.80)
Total Proved Undeveloped	48 985	21 584	9 913	4 248	1 218	4.64
Proved						
Mining	34 372	19 333	10 102	5 076	2 211	4.14
In Situ	38 670	22 216	14 198	9 879	7 340	9.98
E&P Canada	1 885	1 544	1 241	997	806	12.78
Total Canada	74 927	43 094	25 542	15 952	10 357	6.45
North Sea	2 179	2 062	1 924	1 787	1 661	28.27
Other International	1 444	930	623	431	307	15.44
Total Proved	78 549	46 086	28 089	18 171	12 325	6.90
Probable						
Mining	34 288	10 345	4 789	2 870	1 990	5.38
In Situ	76 762	19 253	6 866	3 457	2 245	5.45
E&P Canada	12 309	7 694	5 201	3 731	2 798	30.47
Total Canada	123 359	37 291	16 855	10 058	7 033	7.26
North Sea	1 659	1 380	1 149	966	824	43.48
Other International	3 869	2 120	1 256	795	531	33.42
Total Probable	128 887	40 790	19 260	11 819	8 388	8.08
Proved Plus Probable						
Mining	68 661	29 678	14 891	7 946	4 201	4.47
In Situ	115 432	41 469	21 064	13 336	9 585	7.85
E&P Canada	14 194	9 238	6 442	4 728	3 604	24.06
Total Canada	198 287	80 385	42 398	26 010	17 390	6.75
North Sea	3 838	3 442	3 073	2 754	2 485	32.52
Other International	5 312	3 050	1 879	1 226	838	24.11
Total Proved Plus Probable	207 436	86 877	47 349	29 990	20 713	7.34

Please see Notes (1) and (2) at the end of the Future Net Revenues Tables for important information.

Net Present Value of Future Net Revenues After Income Taxes
as at December 31, 2015
(forecast prices and costs)

	(in $ millions, discounted at % per year)				
	0%	5%	10%	15%	20%
Proved Developed Producing					
Mining	12 862	11 447	7 445	4 777	3 105
In Situ	4 981	4 426	3 953	3 556	3 223
E&P Canada	782	919	952	940	909
Total Canada	18 624	16 792	12 350	9 273	7 237
North Sea	847	819	776	730	686
Other International	—	—	—	—	—
Total Proved Developed Producing	19 472	17 611	13 126	10 003	7 923
Proved Developed Non-Producing					
Mining	—	—	—	—	—
In Situ	30	38	42	44	44
E&P Canada	2	2	1	1	1
Total Canada	32	40	43	45	45
North Sea	—	—	—	—	—
Other International	440	322	246	194	158
Total Proved Developed Non-Producing	472	362	289	239	203
Proved Undeveloped					
Mining	11 850	3 043	(60)	(1 339)	(1 933)
In Situ	23 278	11 667	6 259	3 509	2 000
E&P Canada	1 086	615	284	54	(106)
Total Canada	36 214	15 324	6 483	2 224	(39)
North Sea	138	116	98	83	71
Other International	72	(28)	(81)	(108)	(120)
Total Proved Undeveloped	36 424	15 412	6 500	2 199	(88)
Proved					
Mining	24 712	14 490	7 385	3 438	1 172
In Situ	28 288	16 130	10 255	7 109	5 267
E&P Canada	1 870	1 536	1 237	995	805
Total Canada	54 870	32 156	18 877	11 542	7 243
North Sea	986	935	874	813	757
Other International	512	294	165	86	38
Total Proved	56 368	33 385	19 915	12 441	8 038
Probable					
Mining	25 728	7 577	3 485	2 115	1 503
In Situ	55 845	13 906	4 991	2 555	1 687
E&P Canada	9 063	5 720	3 885	2 798	2 109
Total Canada	90 637	27 202	12 361	7 469	5 299
North Sea	841	707	595	506	436
Other International	1 367	755	452	289	196
Total Probable	92 844	28 664	13 408	8 264	5 930
Proved Plus Probable					
Mining	50 441	22 067	10 870	5 553	2 675
In Situ	84 133	30 036	15 246	9 664	6 953
E&P Canada	10 933	7 255	5 122	3 793	2 913
Total Canada	145 507	59 358	31 238	19 010	12 542
North Sea	1 826	1 641	1 469	1 319	1 193
Other International	1 879	1 049	617	375	233
Total Proved Plus Probable	149 212	62 049	33 323	20 705	13 968

See Note (1) at the end of the Future Net Revenues Tables for important information.

Total Future Net Revenues

as at December 31, 2015
(forecast prices and costs)

(in $ millions, undiscounted)	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenues Before Deducting Future Income Tax Expenses	Future Income Tax Expenses	Future Net Revenues After Deducting Future Income Tax Expenses
Proved Developed Producing								
Mining	160 045	17 906	79 158	28 675	15 086	19 220	6 358	12 862
In Situ	20 914	754	10 765	2 575	504	6 317	1 336	4 981
E&P Canada	4 531	964	1 603	136	1 046	782	—	782
Total Canada	185 490	19 624	91 525	31 386	16 636	26 318	7 694	18 624
North Sea	4 566	—	1 813	155	637	1 962	1 114	847
Other International	—	—	—	—	—	—	—	—
Total Proved Developed Producing	190 056	19 624	93 339	31 541	17 273	28 280	8 808	19 472
Proved Developed Non-Producing								
Mining	—	—	—	—	—	—	—	—
In Situ(3)	11	(3)	(44)	(3)	2	59	29	30
E&P Canada	8	—	4	1	1	2	—	2
Total Canada	19	(2)	(40)	(2)	2	61	29	32
North Sea	—	—	—	—	—	—	—	—
Other International	8 622	5 962	563	440	434	1 224	783	440
Total Proved Developed Non-Producing	8 641	5 959	523	438	436	1 285	813	472
Proved Undeveloped								
Mining	82 393	9 113	44 132	12 549	1 447	15 152	3 302	11 850
In Situ	117 827	17 650	41 067	25 824	992	32 294	9 016	23 278
E&P Canada	4 805	308	1 251	1 669	475	1 102	16	1 086
Total Canada	205 025	27 071	86 450	40 042	2 914	48 548	12 334	36 214
North Sea	818	—	362	223	16	217	79	138
Other International	5 400	3 970	283	609	318	220	148	72
Total Proved Undeveloped	211 243	31 041	87 095	40 874	3 248	48 985	12 561	36 424
Proved								
Mining	242 438	27 019	123 290	41 224	16 533	34 372	9 660	24 712
In Situ	138 752	18 401	51 788	28 395	1 498	38 670	10 382	28 288
E&P Canada	9 344	1 273	2 858	1 807	1 522	1 885	16	1 870
Total Canada	390 534	46 693	177 935	71 426	19 553	74 927	20 057	54 870
North Sea	5 384	—	2 176	378	652	2 179	1 193	986
Other International	14 022	9 932	846	1 049	752	1 444	931	512
Total Proved	409 940	56 624	180 957	72 853	20 957	78 549	22 182	56 368
Probable								
Mining	129 105	18 104	61 152	13 628	1 932	34 289	8 560	25 728
In Situ	225 831	41 089	69 042	37 675	1 264	76 762	20 917	55 845
E&P Canada	21 910	4 355	3 775	1 042	429	12 308	3 245	9 063
Total Canada	376 846	63 547	133 969	52 345	3 625	123 359	32 723	90 637
North Sea	2 414	—	682	36	37	1 659	818	841
Other International	10 913	6 632	266	127	20	3 869	2 502	1 367
Total Probable	390 172	70 179	134 916	52 508	3 682	128 887	36 043	92 844
Proved Plus Probable								
Mining	371 543	45 123	184 442	54 852	18 465	68 661	18 220	50 441
In Situ	364 583	59 490	120 829	66 070	2 762	115 432	31 299	84 133
E&P Canada	31 254	5 628	6 633	2 849	1 951	14 194	3 261	10 933
Total Canada	767 380	110 240	311 904	123 771	23 178	198 287	52 780	145 507
North Sea	7 798	—	2 858	414	689	3 838	2 011	1 826
Other International	24 935	16 563	1 111	1 176	773	5 312	3 433	1 879
Total Proved Plus Probable	800 113	126 803	315 873	125 361	24 640	207 436	58 224	149 212

See Note (3) at the end of the Future Net Revenues Tables.

Future Net Revenues by Product Type[1]
as at December 31, 2015
(forecast prices and costs)

(before income taxes, discounted at 10% per year)	$ millions	Unit Value $/boe[2]
Proved Developed Producing		
SCO	13 312	7.93
Bitumen	1 401	11.99
Light Crude & Medium Crude Oil[4]	2 700	26.68
Heavy Crude Oil	—	—
Conventional Natural Gas[5]	34	6.39
Total Proved Developed Producing	17 447	9.18
Proved		
SCO	17 909	8.25
Bitumen	6 391	3.78
Light Crude & Medium Crude Oil[4]	3 643	21.35
Heavy Crude Oil	109	3.73
Conventional Natural Gas[5]	36	6.39
Total Proved	28 088	6.90
Proved Plus Probable		
SCO	28 814	7.96
Bitumen	7 142	2.98
Light Crude & Medium Crude Oil[4]	8 953	26.97
Heavy Crude Oil	2 390	23.82
Conventional Natural Gas[5]	51	6.45
Total Proved Plus Probable	47 350	7.34

(1) Figures may not add due to rounding.

(2) Unit values are net present values of future net revenues before deducting estimated cash income taxes payable, discounted at 10%, divided by net reserves.

(3) Proved Developed Non-Producing reserves are calculated as the difference between Total Proved Developed and Proved Developed Producing cases, which may result in negative values due to differences in forecasts and related assumptions between the cases.

(4) Light Crude & Medium Crude Oil includes associated byproducts, including solution gas and NGLs.

(5) Natural gas includes associated byproducts, including oil and NGLs.

Notes to Future Net Revenues Tables

In Situ Future Net Revenues

Future net revenues for In Situ properties reflect the flexibility of Suncor's operations, which allows production from these properties to be either upgraded to SCO or sold as non-upgraded bitumen. The proportion of upgraded production is based on estimated available upgrading capacity and can vary depending on pricing of the respective products, maintenance, fluctuations in production from mining and extraction operations, or changes in the company's overall Oil Sands development strategy.

Future net revenues disclosed above include the estimated future sales prices, and associated upgrader operating and sustaining capital costs, assuming that approximately 50-57% of Firebag bitumen production is upgraded to SCO from 2016 to 2033 and 100% thereafter (for total proved plus probable reserves). These assumptions have resulted in a $2.7 billion increase in the net present value of future net revenues (total proved plus probable reserves, before tax, discounted at 10%) attributable to In Situ production relative to the scenario where none of the bitumen is upgraded.

Revenues and the natural gas fuel expense associated with excess power generated from cogeneration facilities at Firebag are included in future net revenues.

Forecast Prices and Costs

Crude oil, natural gas and other important benchmark reference pricing, as well as inflation and exchange rates utilized in the GLJ Reports and the Sproule Reports, were derived using averages of forecasts developed by GLJ, Sproule and McDaniel & Associates Consultants Ltd. dated January 1, 2016. Resultant forecasts are set out below. To the extent that there are fixed or presently determinable future prices or costs to which Suncor is legally bound by contractual or other obligations to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs have been incorporated into the forecast prices as applied to the pertinent properties. The forecast cost and price assumptions include increases in wellhead selling prices, take into account inflation with respect to future operating and capital costs, and assume the continuance of current laws and regulations. The inflation rates utilized in the forecasts were 0.7% in 2016, 1.3% in 2017 and 1.8% in 2018 and thereafter.

Prices Impacting Reserves Tables[1]

Forecast	Brent North Sea[2]	WTI Cushing Oklahoma	WCS Hardisty Alberta[3]	Light Sweet Edmonton Alberta[4]	Pentanes Plus Edmonton Alberta[5]	AECO Gas[6]	B.C. Gas Westcoast Station 2[7]	National Balancing Point North Sea[8]
Year	US$/bbl	US$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/bbl	Cdn$/mmbtu	Cdn$/mmbtu	Cdn$/mmbtu
2016	45.83	44.67	44.64	55.89	60.16	2.57	1.91	7.45
2017	56.73	55.20	54.52	66.47	70.95	3.14	2.70	7.98
2018	65.33	63.47	60.32	73.21	78.05	3.47	3.14	8.28
2019	72.90	71.00	67.42	81.35	86.58	3.80	3.51	8.98
2020	76.67	74.77	70.47	84.57	90.00	3.99	3.70	9.25
2021	80.17	78.24	73.50	87.88	93.46	4.13	3.84	9.53
2022	83.68	81.75	77.25	92.01	97.79	4.30	3.98	9.91
2023	87.34	85.37	80.95	96.24	102.23	4.48	4.16	10.29
2024	89.46	87.32	83.09	98.17	104.29	4.60	4.28	10.57
2025	91.10	88.90	84.56	99.94	106.16	4.70	4.38	10.76
2026	92.76	90.54	86.15	101.79	108.13	4.79	4.47	10.95
2027	94.50	92.22	87.76	103.69	110.14	4.88	4.55	11.14
2028	96.23	93.90	89.33	105.55	112.12	4.96	4.64	11.34
2029	97.98	95.62	90.97	107.49	114.18	5.05	4.72	11.54
2030	99.82	97.40	92.67	109.49	116.31	5.15	4.81	11.74
2031+	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) Benchmark forecast prices have been adjusted for quality differentials and transportation costs applicable to the specific evaluation areas and products.
(2) Price used when determining offshore light crude and medium crude oil and heavy crude oil reserves for E&P Canada, North Sea reserves and Other International reserves.
(3) Price used when determining bitumen reserves presented as In Situ and Mining reserves as well as for determining bitumen pricing for royalty calculation purposes.
(4) Price used when determining SCO reserves presented as In Situ and Mining reserves.
(5) Price used when determining the cost of diluent associated with bitumen reserves presented as In Situ and Mining reserves, as well as when accounting for diluent in determining bitumen pricing for royalty calculation purposes. A bitumen/diluent ratio of approximately two barrels of bitumen for one barrel of diluent was used. Price also used when determining NGLs reserves.
(6) Price used when determining natural gas input costs for the production of SCO and bitumen reserves.
(7) Price used when determining conventional natural gas reserves for E&P Canada areas.
(8) Price used when determining conventional natural gas reserves presented as North Sea reserves.

Foreign Exchange Rates Impacting Forecast Prices

Forecast	US$/Cdn$ Exchange Rate	Cdn$/€ Exchange Rate	Cdn$/£ Exchange Rate
Year			
2016	0.735	1.497	2.041
2017	0.767	1.435	2.022
2018	0.802	1.372	1.933
2019	0.817	1.347	1.898
2020	0.833	1.320	1.860
2021+	0.842	1.307	1.842

Disclosure of After-Tax Net Present Values of Future Net Revenues

Values presented in the table for Net Present Value of Future Net Revenues After Income Taxes reflect income tax burdens of assets at an individual asset level (for In Situ) or at a business area or legal entity level (for Mining, North Sea and E&P Canada) based on tax pools associated with that business area or legal entity. Income taxes for Other International assets are determined by their respective EPSAs. Suncor's actual corporate legal entity structure for income taxes and income tax planning has not been considered, and, therefore, the total value for income taxes presented in the total future net revenues table may not provide an estimate of the value at the corporate entity level, which may be significantly different. The 2015 audited Consolidated Financial Statements and the MD&A should be consulted for information on income taxes at the corporate entity level.

Additional Information Relating to Reserves Data

Future Development Costs[1]
as at December 31, 2015
(forecast prices and costs)

($ millions)	2016	2017	2018	2019	2020	Remainder	Total	Discounted At 10%
Proved								
Mining	3 906	3 521	2 422	2 110	2 472	26 793	41 224	20 074
In Situ	812	780	1 196	1 879	679	23 051	28 395	10 618
E&P Canada	696	370	41	94	94	512	1 807	1 392
Total Canada	5 414	4 670	3 658	4 082	3 245	50 356	71 426	32 085
North Sea	156	116	11	9	13	72	378	307
Other International	18	91	97	152	122	570	1 049	551
Total Proved	5 588	4 877	3 766	4 243	3 380	50 998	72 853	32 943
Proved Plus Probable								
Mining	3 920	3 536	2 466	2 166	2 594	40 170	54 852	21 865
In Situ	796	826	850	1 379	894	61 325	66 070	11 617
E&P Canada	853	540	144	215	295	802	2 849	2 111
Total Canada	5 569	4 902	3 459	3 760	3 784	102 298	123 771	35 594
North Sea	156	116	11	9	13	108	414	318
Other International	18	103	98	156	125	676	1 176	587
Total Proved Plus Probable	5 743	5 121	3 568	3 925	3 921	103 082	125 361	36 499

(1) Figures may not add due to rounding.

Development costs include costs associated with both developed and undeveloped reserves. Significant development activities and costs for 2016 are expected to include:

- Development activities for Fort Hills continue to focus on procurement and field construction activities. For Mining, turnaround and major maintenance at Upgrader 2, development of fluid management facilities for Oil Sands Base, and utilities sustainment, mining and tailings projects at Syncrude. Remaining development costs for Oil Sands Base and Syncrude relate to capital investments that maintain the production capacity of existing facilities, including, but not limited to, major maintenance, truck and shovel replacement, the replenishment of catalysts in hydrotreating units at the upgraders and improvements to utilities, roads and other facilities.
- For both Firebag and MacKay River operations within In Situ, the drilling of new well pairs as well as the design and construction of new well pads that are expected to maintain existing production levels in future years.
- For E&P Canada, construction activities at Hebron, as well as development drilling at Hibernia, the HSEU and White Rose.
- For North Sea, continuation of Golden Eagle development drilling.

Management currently believes that internally generated cash flows, existing and future credit facilities, and access to debt capital markets are sufficient to fund future development costs. There can be no guarantee that funds will be available or that Suncor will allocate funding to develop all of the reserves attributed in the GLJ Reports and the Sproule Reports. Failure to develop those reserves would have a negative impact on future cash flow from operating activities.

Interest expense or other costs of external funding are not included in the reserves and future net revenues estimates and could reduce future net revenues to some degree depending upon the funding sources utilized. Suncor does not anticipate that interest expense or other funding costs on their own would make development of any property uneconomic.

Abandonment and Reclamation Costs

The company completes an annual review of its consolidated abandonment and reclamation cost estimates. The estimates are based on the anticipated method and extent of restoration, consistent with legal requirements, technological advances and the possible future use of the site.

As at December 31, 2015, Suncor estimated its undiscounted, uninflated abandonment and reclamation costs for its upstream assets to be approximately $9.7 billion (discounted at 10%, approximately $3.0 billion). Abandonment and reclamation costs are limited to current disturbances at December 31, 2015, and exclude estimated abandonment and reclamation costs for its Refining and Marketing assets ($0.2 billion, undiscounted and uninflated). Suncor estimates that it will incur $1.3 billion of its identified abandonment and reclamation costs during the next three years (undiscounted: 2016 – $0.4 billion, 2017 – $0.4 billion, 2018 – $0.5 billion), more than 80% of which is associated with Oil Sands mining operations.

Approximately $24.6 billion (inflated and undiscounted) has been deducted as abandonment and reclamation costs in estimating the future net revenues from proved plus probable reserves, including $21.2 billion related to the company's oil sands upgraders, extraction facilities, tailings ponds, sub-surface wells and central processing facilities, which includes amounts related to current disturbances.

As a result of regulatory changes to reserves reporting requirements, the abandonment and reclamation cost estimate included in the net present values of the company's proved and probable reserves now include costs related to the reclamation of disturbed land from oil sands mining activities, future mining disturbances, the treatment of legacy oil sands tailings, the decommissioning of oil sands and natural gas processing facilities and well pads, existing and future reserves wells and associated service wells, disturbed lease sites, and future lease site disturbances. Historically, the abandonment and reclamation cost estimates included in the net present values of proved and probable reserves were limited to the abandonment of production and service wells, including forecasted wells for undeveloped reserves.

Gross Proved and Probable Undeveloped Reserves
The tables below outline the gross proved and probable undeveloped reserves and represent undeveloped reserves additions resulting from acquisitions, discoveries, infill drilling, improved recovery and/or extensions in the year when the events first occurred.

Gross Proved Undeveloped Reserves[1]
(forecast prices and costs)

	2013		2014		2015	
	First Attributed	Total at December 31 2013	First Attributed	Total at December 31 2014	**First Attributed**	**Total at December 31 2015**
SCO (mmbbls)						
Mining	—	—	—	—	—	—
In Situ	75	564	—	532	—	**584**
Total SCO	75	564	—	532	—	**584**
Bitumen (mmbbls)						
Mining	845	845	—	845	**207**	**1 052**
In Situ	74	875	—	830	—	**741**
Total Bitumen	918	1 720	—	1 674	**207**	**1 792**
Light Crude & Medium Crude Oil (mmbbls)						
E&P Canada[2]	2	27	38	52	—	**22**
North Sea	—	25	—	16	—	**10**
Other International[3]	—	5	—	2	—	**51**
Total Light Crude & Medium Crude Oil	2	57	38	70	—	**82**
Heavy Crude Oil (mmbbls)						
E&P Canada[2]	—	—	—	—	—	**30**
North Sea	—	—	—	—	—	—
Other International[3]	—	—	—	—	—	—
Total Heavy Crude Oil	—	—	—	—	—	**30**
Natural Gas (bcfe)[4]						
E&P Canada[2]	4	5	—	—	—	—
North Sea	—	1	—	1	—	**1**
Other International[3]	—	—	—	—	—	—
Total Natural Gas	4	6	—	1	—	**1**
Total (mmboe)	996	2 342	38	2 277	**207**	**2 488**

Gross Probable Undeveloped Reserves[1]
(forecast prices and costs)

	2013		2014		**2015**	
	First Attributed	Total at December 31 2013	First Attributed	Total at December 31 2014	**First Attributed**	**Total at December 31 2015**
SCO (mmbbls)						
Mining	—	265	—	265	**—**	**265**
In Situ	—	1 074	—	1 112	**—**	**1 207**
Total SCO	—	1 339	—	1 378	**—**	**1 473**
Bitumen (mmbbls)						
Mining	397	397	—	408	**107**	**542**
In Situ	—	369	—	268	**—**	**250**
Total Bitumen	397	766	—	677	**107**	**791**
Light Crude & Medium Crude Oil (mmbbls)						
E&P Canada[2]	22	236	10	189	**5**	**88**
North Sea	—	23	—	13	**—**	**4**
Other International[3]	—	9	1	3	**—**	**42**
Total Light Crude & Medium Crude Oil	22	267	11	205	**5**	**133**
Heavy Crude Oil (mmbbls)						
E&P Canada[2]	—	—	—	—	**—**	**82**
North Sea	—	—	—	—	**—**	**—**
Other International[3]	—	—	—	—	**—**	**—**
Total Heavy Crude Oil	—	—	—	—	**—**	**82**
Natural Gas (bcfe)[4]						
E&P Canada[2]	17	21	—	3	**—**	**3**
North Sea	—	2	—	1	**—**	**1**
Other International[3]	—	—	—	—	**—**	**—**
Total Natural Gas	17	23	—	4	**—**	**3**
Total (mmboe)	422	2 376	11	2 260	**112**	**2 479**

(1) Figures above may not add due to rounding.
(2) E&P Canada includes properties previously held by Suncor and subsequently disposed of in 2013 and 2014.
(3) Other International includes certain volumes for Libya that have been reclassified to undeveloped due to facility damage.
(4) All conventional natural gas, other than immaterial amounts of NGLs (less than 0.6 mmbbls).

Undeveloped In Situ reserves, which constitute approximately 53% of Suncor's gross proved undeveloped reserves and 59% of Suncor's gross probable undeveloped reserves have been assigned to reserves areas which are not classified as developed producing. Where supported by core hole wells, proved undeveloped reserves have been attributed to regions within 1.2 km from currently drilled or near-term planned production wells where AER approval is pending and, in the case of Firebag, also within 2.4 km from producing wells. Suncor has delineated In Situ reserves to a high degree of certainty through seismic data and core hole drilling, 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. Further delineation is pursued through annual core hole drilling programs. Management uses integrated plans to forecast future development. These detailed plans align current production, processing and pipeline constraints (which, in the case of processing constraints, do not permit Suncor to develop all of its undeveloped In Situ reserves within two years), capital spending commitments and future development for the next ten years, and are reviewed and updated annually for internal and external factors affecting planned activity. The timing associated with developing undeveloped In Situ reserves is a function of the forecasts of the declining production from existing In Situ wells, and will take several years to develop, depending on performance. When existing wells decline, Suncor commences development of the reserves and wells surrounding the declining areas. This will entail drilling replacement well pairs and constructing sustaining pads. The economic viability of developing the sustaining pads and associated well pairs is tested to ensure that ongoing development is economic as required for reserves assessment. Sustaining pads are at various stages of development, from pad regulatory approval awaiting final internal approval to pad regulatory application to more detailed continuing core hole evaluation. Final internal approvals are aligned with declining production from the existing In Situ wells.

Undeveloped Mining reserves constitute approximately 42% of Suncor's gross proved undeveloped reserves and 32% of Suncor's gross probable undeveloped reserves, and relate to the Fort Hills mining project and Syncrude Aurora South mining area, which have regulatory approvals substantially in place and are well-delineated by core hole drilling. Suncor is currently completing construction of the Fort Hills mining area, and first oil is expected by the fourth quarter of 2017. The co-owners of Syncrude do not expect that the Aurora South mining area will come on-stream before 2023, when production from the Mildred Lake mining area is expected to be complete.

Undeveloped conventional reserves (light crude oil and medium crude oil, heavy crude oil, and natural gas) constitute approximately 5% of Suncor's gross proved undeveloped reserves and approximately 9% of Suncor's gross probable undeveloped reserves. Undeveloped conventional reserves primarily relate to the company's offshore assets at E&P Canada, mainly associated with Hebron which is currently under development (first oil expected in 2017), and under-drilled or undrilled fault blocks related to extension areas in Hibernia, White Rose and Terra Nova. In 2015, extensive damage was sustained in Libya to the facilities associated with EPSA 5. As a result, Suncor has reclassified the associated reserves for EPSA 5 from developed non-producing to undeveloped. In developing undeveloped conventional reserves, Suncor considers existing facility capacity, capital allocation plans, and remaining reserve availability. Accordingly, in some cases, it will take longer than two years to develop all of the currently assigned undeveloped conventional reserves. Suncor plans to develop the majority of the conventional proved undeveloped reserves over the next five years and the majority of the conventional probable undeveloped reserves over the next seven years.

Properties with no Attributed Reserves

The following table is a summary of properties to which no reserves are attributed as at December 31, 2015. For lands in which Suncor holds interests in different formations under the same surface area pursuant to separate leases, the area has been counted for each lease.

Country	Gross Hectares	Net Hectares
Canada	6 581 794	3 755 580
Libya	2 950 978	1 339 489
U.S. – Alaska	481 740	160 564
Syria	345 194	345 194
Norway	286 775	76 775
U.K.	119 541	35 599
Australia (overriding royalty interest only)	113 027	—
Total	10 879 049	5 713 201

Suncor's undeveloped petroleum assets include exploration properties in a preliminary phase of evaluation, to discovery areas where tenure to the property is held indefinitely on the basis of hydrocarbon test results, but where economic development is not currently possible or has not yet been sanctioned. Certain Mining and In Situ properties may be in a relatively mature phase of evaluation, where a significant amount of development has occurred; however, reserves cannot be attributed due to one or more contingencies, such as project sanction. In many cases where reserves are not attributed to lands containing one or more discovery wells, the key limiting factor is the lack of available production infrastructure. Each year, as part of the company's process to review the economic viability of its properties, some properties are selected for further development activities, while others are temporarily deferred, sold, swapped or relinquished back to the mineral rights owner.

In 2016, Suncor's rights to 48,392 net hectares in Canada, 37,325 net hectares in Norway and 17,094 net hectares in the U.K. are scheduled to expire. The expiries include approximately 2,800 net hectares in In Situ and 2,200 net hectares in Mining. Substantial portions of expiring lands may have their tenure continued beyond 2016 through the conduct of work programs and/or the payment of prescribed fees to the rights owner.

Oil and Gas Properties and Wells(1)

The following table is a summary of oil and gas wells as at December 31, 2015.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing(2)(3)		Producing		Non-Producing(2)(3)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta – In Situ(4)	286.0	286.0	322.0	262.3	—	—	—	—
British Columbia	—	—	—	—	28.0	26.5	21.0	16.9
Newfoundland	66.0	16.6	5.0	1.8	—	—	—	—
North Sea	37.0	10.8	7.0	2.0	—	—	—	—
Other International(5)	—	—	419.0	211.1	—	—	6.0	6.0
Total	389.0	313.4	753.0	477.2	28.0	26.5	27.0	22.9

(1) All oil and gas wells are onshore, other than Newfoundland and the North Sea.

(2) Non-producing wells include, but are not limited to, wells where there is no near-term plan for abandonment, wells where drilling has finished but the well has not been completed, wells requiring maintenance or workover where the resumption of production is not known, and wells that have been shut in and the date of resumption of production is not known with reasonable certainty.

(3) Non-producing wells do not necessarily lead to classification of non-producing reserves.

(4) SAGD well pairs are counted as one well. Wells where steam injection has commenced are classified as producing.

(5) Other International includes wells associated with the company's suspended operations in Syria and Libya.

There are no producing wells associated with Mining properties. Suncor has no proved developed non-producing reserves or probable developed non-producing reserves in its Mining reserves.

For In Situ properties, proved non-producing reserves and probable non-producing reserves are associated with wells that have been drilled within the last three years, which require further capital for completion and tie-in to facilities to bring the wells on-stream. Because this capital is small relative to the cost to drill, complete and tie-in a well pair, the associated reserves are considered developed.

For Other International, non-producing reserves are associated with wells in Libya that were suspended in the fourth quarter of 2015, due to political unrest in the country, which resulted in the closure of export terminal operations. Production in Libya remains impacted by political unrest, with the timing of a return to normal operations remaining uncertain. As such, all reserves associated with EPSAs 1-4 have been classified as non-producing, while reserves associated with EPSA 5, where facilities have been damaged, have been classified as undeveloped in light of the costs required to repair facilities and restore production.

Costs Incurred

The table below summarizes the company's costs incurred related to its oil and gas activities for the year ended December 31, 2015.

($ millions)	Exploration Costs	Proved Property Acquisition Costs	Unproved Property Acquisition Costs	Development Costs	Total
Canada – Mining and In Situ	157	360	18	3 553	4 088
Canada – E&P Canada	131	—	1	869	1 001
Total Canada	288	360	19	4 422	5 089
North Sea	252	—	—	164	416
Other International	12	—	—	—	12
Total	552	360	19	4 586	5 517

Exploration and Development Activities

The table below outlines the gross and net exploratory and development wells the company completed during the year ended December 31, 2015.

	Exploratory Wells(1)		Development Wells	
Total number of wells completed	Gross	Net	Gross	Net
Canada – Oil Sands				
Oil	—	—	24	24
Service(2)	—	—	29	29
Stratigraphic Test(3)	386.0	241.3	151	61
Total	386.0	241.3	204	114
Canada – E&P Canada				
Oil	—	—	3	0.7
Dry Hole	1	0.4	1	0.2
Natural Gas	—	—	—	—
Service(2)	—	—	1	0.2
Stratigraphic Test(3)	—	—	—	—
Total	1	0.4	5	1.1
North Sea				
Oil	—	—	7	1.9
Service(2)	—	—	4	1.1
Dry Hole	4	2.5	—	—
Stratigraphic Test(3)	—	—	—	—
Total	4	2.5	11	3.0

(1) Exploratory wells for Oil Sands include activity related to technology pilot projects.

(2) Service wells for Oil Sands include the injection well in a SAGD well pair, in addition to observation and disposal wells. Service wells for E&P Canada include water and gas injection wells. Service wells for North Sea include water injection wells.

(3) Stratigraphic test wells for Oil Sands include core hole drilling wells.

Significant exploration and development activities in 2015 included:

- For Mining, stratigraphic test well drilling programs and other survey work at Oil Sands Base and Syncrude to provide additional information on areas the company expects to mine in the near term.
- For In Situ, the drilling of new well pairs and infill wells at Firebag and MacKay River that are expected to assist in maintaining production levels in future years, stratigraphic test well drilling programs at MacKay River, Meadow Creek, Firebag and Lewis to further delineate resources, and activity to start up pilot technology projects.
- For E&P Canada, construction activities at Hebron, development drilling for Hibernia, the HSEU, White Rose and the South White Rose Extension. E&P Canada also included exploration drilling in the Shelburne Basin.
- For North Sea, continuation of development drilling for Golden Eagle, and exploration drilling in Norway and U.K. sectors of North Sea.

For significant exploration and development activities expected to occur in 2016 and beyond, see Narrative Description of Suncor's Businesses and Future Development Costs herein.

Production History(1)

2015	Q1	Q2	Q3	Q4	Year Ended
Canada – Oil Sands(2)					
Total production (mbbls/d)	475.6	448.7	458.4	470.6	463.4
SCO (mbbls/d)	381.7	352.3	343.0	323.1	349.9
Non-upgraded bitumen (mbbls/d)	93.9	96.4	115.4	147.5	113.5
($/bbl)					
Average price realized	48.30	61.63	48.85	42.55	50.26
Royalties	(0.44)	(0.93)	(1.14)	(0.22)	(0.67)
Total cash operating costs(3)	(28.95)	(29.57)	(27.89)	(28.82)	(28.80)
Canada – Light Crude & Medium Crude Oil(4)					
Total production (mbbls/d)	58.1	37.0	36.9	43.5	43.8
($/bbl)					
Average price realized(5)	66.38	78.23	59.09	52.51	65.12
Royalties	(17.58)	(16.38)	(4.39)	(5.79)	(12.49)
Production costs	(11.33)	(18.36)	(20.63)	(19.67)	(16.33)
Netback	37.47	43.49	34.07	27.05	36.30
North Sea – Light Crude & Medium Crude Oil(6)					
Total production (mboe/d)	61.2	66.9	67.0	63.2	64.6
($/boe)					
Average price realized(5)	64.48	72.84	62.86	54.91	63.85
Royalties	—	—	—	—	—
Production costs	(9.65)	(8.52)	(8.42)	(8.42)	(8.70)
Netback	54.83	64.32	54.44	46.49	55.15

(1) Production and liftings in Libya have been intermittent and are not considered material to Suncor and therefore are not included.

(2) Suncor measures cash operating cost on a production volumes basis for its Oil Sands operations. For this reason, a netback calculation for SCO and bitumen is not presented. Amounts presented include results from the company's share of Syncrude.

(3) Non-GAAP financial measures. See the Advisories section of this AIF.

(4) Volumes exclude natural gas and NGLs production from E&P Canada onshore properties, which is not considered material to Suncor.

(5) Average price realized is net of transportation costs, but before royalties.

(6) Volumes include field production for associated gas and NGLs.

The following table provides the production volumes on a working-interest basis, before royalties for each of Suncor's significant fields for the year ended December 31, 2015.

	SCO	Bitumen	Light & Medium Oil
	mbbls/d	mbbls/d	mbbls/d
Mining – Suncor	239.0	—	—
Mining – Syncrude	30.0	—	—
Firebag	80.3	83.6	—
MacKay River	0.7	29.8	—
Buzzard	—	—	49.8
GEAD	—	—	14.8
Hibernia	—	—	18.1
White Rose	—	—	12.2
Terra Nova	—	—	13.5
Total	350.0	113.4	108.4

Production Estimates

The table below outlines the production estimates for 2016 that are included in the estimates of gross proved reserves and gross probable reserves as at December 31, 2015. Total Proved plus Probable production estimates from Suncor's mining operations (excluding Syncrude) are 222.3 mbbls/d of SCO, approximately 39% of total estimated production for 2016, and from Firebag are 165.0 mbbls/d of SCO and bitumen, approximately 29% of total estimated production for 2016.

	SCO (mbbls/d)		Bitumen (mbbls/d)		Light & Medium Oil (mbbls/d)		Natural Gas (mmcfe/d)[1]		Total (mmboe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada										
Proved	319	314	106	105	42	34	13	12	469	455
Probable	21	21	8	8	9	8	1	1	38	37
Proved Plus Probable	340	335	114	112	51	42	14	13	507	492
North Sea										
Proved	—	—	—	—	46	46	5	5	47	47
Probable	—	—	—	—	4	4	1	1	4	4
Proved Plus Probable	—	—	—	—	50	50	5	5	51	51
Other International										
Proved	—	—	—	—	9	2	—	—	9	2
Probable	—	—	—	—	—	—	—	—	—	—
Proved Plus Probable	—	—	—	—	9	2	—	—	9	2
Total										
Proved	319	314	106	105	96	82	18	16	524	504
Probable	21	21	8	8	13	12	2	2	42	41
Proved Plus Probable	340	335	114	112	109	94	20	18	566	545

(1) Figures above may not add due to rounding.

Work Commitments
The practice of governments requiring companies to pledge to carry out work commitments in exchange for the right to carry out exploration for and development of hydrocarbons is common, particularly in unexplored or lightly explored regions of the world. The following table shows the estimated values of work commitments Suncor has made in regard to the lands it holds as at December 31, 2015. These commitments run through 2021 and beyond, and are primarily for conducting seismic programs and drilling exploration wells.

Country/Area ($ millions)	2016	Total
Canada	—	96
North Sea	1	1
Other International	—	497

Forward Contracts
Suncor may use financial derivatives to manage its exposure to fluctuations in commodity prices; however, Suncor did not consider any financial derivative transactions to be material in 2015. A description of Suncor's use of such instruments is provided in the 2015 audited Consolidated Financial Statements and related MD&A for the year ended December 31, 2015.

Tax Horizon
In 2015, Suncor was subject to cash tax in the majority of the jurisdictions in which it generates earnings, including earnings related to its Canadian, North Sea and Other International production.

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