

DISTINCTION ENERGY CORP.

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

National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* (“NI 51-101”) establishes a standard of disclosure for all Canadian reporting issuers in upstream oil and natural gas activities and reserves definitions for proved and probable reserves categories. The reserves disclosure presented below conforms to the requirements of NI 51-101. All of Distinction Energy Corp.’s (“**Distinction**” or the “**Corporation**”) reserves are in western Canada, specifically in the province of Alberta.

The Corporation engaged GLJ Ltd. (“**GLJ**”), independent qualified reserves evaluators, to evaluate and report on 100 percent of the Corporation’s proved and proved plus probable reserves. The crude oil, natural gas and natural gas liquids reserves of the Corporation were evaluated by GLJ, with an effective date of December 31, 2020 in a report dated March 5, 2021 (the “**GLJ Report**”).

Definitions, abbreviations, notes and conversions used throughout the following tables can be found in Appendix “A”.

The use of the boe unit of measurement may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf of natural gas to 1 barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. The estimated future net revenue contained in the following tables does not represent the fair market value of reserves associated with Distinction’s assets and properties. Tables may not add due to rounding.

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.

Reserves Data (Forecast Prices and Costs)

Reserves Summary (Forecast Prices and Costs)

	Conventional Natural Gas (Mmcf)		Shale Gas (Mmcf)		Natural Gas Liquids (Mbbls)		Boe (6:1) (Mboe)	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾
Proved ^{(3) (6)}								
Developed producing ⁽⁴⁾	3,961	3,530	45,831	41,461	4,942	3,815	13,241	11,313
Developed non-producing ⁽⁴⁾	-	-	-	-	-	-	-	-
Undeveloped ⁽⁵⁾	-	-	58,678	55,387	7,804	6,977	17,584	16,208
Total proved	3,961	3,530	104,509	96,848	12,746	10,792	30,825	27,522
Probable ^{(3) (6)}	4,631	4,161	95,954	89,537	13,946	11,242	30,710	26,858
Total proved plus probable	8,592	7,690	200,462	186,385	26,692	22,034	61,534	54,380

Net Present Value of Future Net Revenue Summary (Forecast Prices and Costs)

	Before Income Taxes Discounted at					Unit Value Before Income Tax Discounted at 10%	
	0%	5%	10%	15%	20%	\$/boe	\$/Mcfe
	(\$ 000's)	(\$ 000's)	(\$ 000's)	(\$ 000's)	(\$ 000's)		
Proved ^{(3) (6)}							
Developed producing ⁽⁴⁾	140,701	121,706	106,304	94,206	84,655	17.34	2.89
Developed non-producing ⁽⁴⁾	-	-	-	-	-	-	-
Undeveloped ⁽⁵⁾	157,752	91,793	52,313	27,940	12,372	6.24	1.04
Total proved	298,453	213,499	158,617	122,146	97,027	11.22	1.87
Probable ^{(3) (6)}	473,353	267,525	169,809	118,299	88,429	11.10	1.85
Total proved plus probable	771,807	481,024	328,426	240,445	185,456	11.16	1.86

	After Income Taxes Discounted at				
	0%	5%	10%	15%	20%
	(\$ 000's)	(\$ 000's)	(\$ 000's)	(\$ 000's)	(\$ 000's)
Proved ^{(3) (6)}					
Developed producing ⁽⁴⁾	140,701	121,706	106,304	94,206	84,655
Developed non-producing ⁽⁴⁾	-	-	-	-	-
Undeveloped ⁽⁵⁾	157,752	91,793	52,313	27,940	12,372
Total proved	298,453	213,499	158,617	122,146	97,027
Probable ^{(3) (6)}	366,464	211,927	138,079	98,898	75,934
Total proved plus probable	664,917	425,426	296,696	221,044	172,961

Total Future Net Revenue (Undiscounted)

	Revenue	Royalties	Operating Costs	Capital Development Costs	Well Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes ⁽⁸⁾	Future Net Revenue After Income Taxes
	(\$ 000's)	(\$ 000's)	(\$ 000's)	(\$ 000's)	(\$ 000's)	(\$ 000's)	(\$ 000's)	(\$ 000's)
Proved ^{(3) (6)}								
Developed producing ⁽⁴⁾	397,853	63,809	179,282	1,240	12,821	140,701	-	140,701
Developed non-producing ⁽⁴⁾	-	-	-	-	-	-	-	-
Undeveloped ⁽⁵⁾	636,133	58,167	210,311	203,970	5,932	157,752	-	157,752
Total proved	1,033,986	121,977	389,593	205,210	18,752	298,453	-	298,453
Probable ^{(3) (6)}	1,265,330	209,065	394,413	180,350	8,149	473,354	106,890	366,464
Total proved plus probable	2,299,316	331,041	784,006	385,561	26,901	771,807	106,890	664,917

Future Net Revenue by Product Type (Forecast Prices and Costs)

Reserve Category	Product Type	Future Net Revenue Before Income Taxes (discounted at 10%)		
		(\$ 000's)	\$/boe	\$/Mcf
Proved Producing	Conventional natural gas (including by-products)	1,873	3.18	0.53
	Shale gas (including by-products)	104,431	8.39	1.40
	TOTAL	106,304	8.03	1.34
Total Proved	Conventional natural gas (including by-products)	1,873	3.18	0.53
	Shale gas (including by-products)	156,744	9.72	1.62
	TOTAL	158,617	5.76	0.96
Total Proved Plus Probable	Conventional natural gas (including by-products)	5,047	3.96	0.66
	Shale gas (including by-products)	323,379	10.44	1.74
	TOTAL	328,426	6.04	1.01

Summary of Pricing Assumptions

This summary table identifies the benchmark reference pricing provided by GLJ, Distinction's independent qualified reserves evaluators, and used in the evaluation of the Corporation's reserves.

Pricing assumptions	Light and Medium Oil		Natural Gas Liquids			Conventional Natural Gas and Shale Gas		Inflation Rate	Exchange Rate
	West Texas Intermediate Cushing Oklahoma (US\$/bbl)	Edmonton Par Price 40 API (Cdn\$/bbl)	Edmonton Propane (Cdn\$/bbl)	Edmonton Butane (Cdn\$/bbl)	Edmonton Pentanes Plus (Cdn\$/bbl)	U.S. Henry Hub Gas Price (US\$/Mmbtu)	AECO/NIT spot price (Cdn\$/Mmbtu)	%/year	US\$/Cdn\$
Forecast									
2021	48.00	55.49	19.43	27.75	60.65	2.75	2.72	0.0	0.775
2022	51.50	60.78	24.31	36.47	65.36	2.80	2.67	1.0	0.765
2023	54.50	63.82	25.53	41.48	70.07	2.85	2.60	2.0	0.760
2024	57.79	68.14	27.26	44.29	74.72	2.90	2.60	2.0	0.760
2025	58.95	69.67	27.87	45.29	76.25	2.95	2.65	2.0	0.760
2026	60.13	71.22	28.49	46.30	77.80	3.01	2.71	2.0	0.760
2027	61.33	72.80	29.12	47.32	79.38	3.07	2.76	2.0	0.760
2028	62.56	74.42	29.77	48.37	81.00	3.13	2.81	2.0	0.760
2029	63.81	76.07	30.43	49.44	82.64	3.19	2.87	2.0	0.760
2030	65.09	77.59	31.03	50.43	84.30	3.25	2.92	2.0	0.760
2031+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.760

The Corporation received the following weighted average prices in 2020, excluding gains and losses on financial and physical commodity price contracts.

Shale gas (\$/mcf)	Conventional Natural gas (\$/mcf)	Natural gas liquids (\$/bbl)	Total (\$/boe)
2.48	2.45	33.58	23.14

Reconciliation of Corporation's Gross ⁽¹⁾ Reserves Using Forecast Prices and Costs

		Conventional Natural Gas (Mmcf)			Shale Gas (Mmcf)		
		Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
December 31, 2019		5,016	5,499	10,515	103,523	97,460	200,982
Extensions and Improved Recovery		-	-	-	11,630	(4,806)	6,824
Technical revisions		(85)	(650)	(735)	5,179	1,492	6,671
Discoveries		-	-	-	-	-	-
Acquisitions		-	-	-	2,346	819	3,165
Dispositions		-	-	-	-	-	-
Economic factors		(246)	(218)	(463)	(10,751)	988	(9,763)
Production		(725)	-	(725)	(7,418)	-	(7,418)
December 31, 2020		3,961	4,631	8,592	104,509	95,954	200,462

		Natural Gas Liquids (Mbbls)			Boe (Mboe)		
		Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
December 31, 2019		12,005	11,102	23,107	30,095	28,262	58,356
Extensions and Improved Recovery		1,797	2,315	4,112	3,735	1,514	5,249
Technical revisions		909	77	986	1,758	217	1,975
Discoveries		-	-	-	-	-	-
Acquisitions		379	152	531	770	289	1,058
Dispositions		-	-	-	-	-	-
Economic factors		(1,264)	301	(963)	(3,097)	429	(2,668)
Production		(1,079)	-	(1,079)	(2,436)	-	(2,436)
December 31, 2020		12,746	13,946	26,692	30,825	30,710	61,534

The Corporation had a disciplined capital program in 2020 in which it drilled, completed and brought 3.0 (3.0 net) horizontal Montney wells on production in the Bigstone area. Proved developed producing extensions incorporated in the GLJ Report were the result of the 3.0 (3.0 net) above-mentioned Montney wells. Undeveloped Montney drilling locations in the GLJ Report decreased by 12 gross (6.8 net) in the total proved category and by 24 gross (17.5 net) in the total proved plus probable category compared to Distinction's reserves report as at December 31, 2019. The reduction in well count is mainly due to changing the well density from 6 wells per section to 4 wells per section in liquid-rich west Bigstone. Overall, the Corporation's reserves stayed flat or slightly increased across different categories while future development costs decreased resulting in a more capital efficient method of capturing the reserves. Changes in reserves due to extensions and improved recovery are due to the improvements in type curves for various areas as a result of improved completion techniques utilized by Distinction and results seen over 2020.

Increase in reserves due to acquisitions represents the working interest of a partner who chose not to participate in 3 wells from the 2020 drilling program. Changes in reserves due to economic factors occur when there is a change in the economic limit of a well because of a change in factors including commodity prices, operating costs and transportations costs compared to the previous year. These changes are determined prior to any consideration of technical revisions. Decreases in reserves due to production represent reserves that were produced from the Corporation's properties during 2020.

Additional Information Relating to Reserves Data

Undeveloped Reserves ⁽⁵⁾

Proved and Probable Undeveloped Reserves

The following table sets forth the volumes of proved undeveloped and probable undeveloped reserves that were first attributed to each product type in each of the most recent three financial years:

Product Type	Units	2018	2019	2020
Proved Undeveloped				
Shale gas	Mmcf	26,309	9,671	9,485
Conventional natural gas	Mmcf	-	-	-
Natural gas liquids	Mbbl	3,722	1,325	1,365
Total	Mboe	8,107	2,937	2,946

Probable Undeveloped				
Shale gas	Mmcf	41,280	11,075	-
Conventional natural gas	Mmcf	-	-	-
Natural gas liquids	Mbbl	5,044	1,654	2,358
Total	Mboe	11,924	3,500	2,358

The future development costs are capital costs required in the future for Distinction to convert proved and probable undeveloped reserves into proved developed producing reserves. On an on-going basis Distinction typically uses its internally generated cash flow, proceeds from dispositions, available credit facilities and new equity financings, if available on favourable terms, to fund requirements for future development required to develop the proved or the proved plus probable reserves.

Development of undeveloped reserves within the GLJ Report are scheduled to deliver approximately 8,000 boe/d and 10,000 boe/d in total proved and total proved plus probable, respectively in 2022 and stay flat while the inventory lasts in each respective category. Sufficient processing capacity exists to support proved and proved plus probable undeveloped reserves coming on production. A number of other factors considered in determining the development schedule of undeveloped reserves include resource loading to address appropriate activity levels and the anticipated availability of free cash flow to fund development.

In the GLJ Report, Distinction has anticipated that approximately 40 percent of future development costs relating to the development of Distinction's proved undeveloped reserves will occur within two years, and all future development costs in respect of these reserves are anticipated to occur within six years. In the GLJ Report, Distinction has anticipated that approximately 22 percent of future development costs relating to the development of Distinction's undeveloped proved plus probable reserves will occur within two years

and all future development costs in respect of these undeveloped reserves are anticipated to occur within 11 years to appropriately align with the Company's cash flow from development.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex and requires significant judgments and decisions based upon a number of variable factors and assumptions, such as commodity prices, projected production from the properties, the assumed effects of regulation by government agencies and future operating costs. All of these estimates may vary from actual results. The reserve estimates contained in this NI 51-101F1 disclosure are based on current production forecasts, prices and economic conditions. Estimates of the recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, may vary. The Corporation's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates and such variances could be material.

The Corporation estimates the total cost of future abandonment and reclamation for its existing wells, including their associated production facilities and infrastructure, and the expected timing of the costs to be incurred in future periods. The Corporation has a process for estimating these costs, which considers past experience, applicable current regulations, technology and industry standards, actual and anticipated costs, the type and depth of the well (or the nature and size of the facility), and the geographic location. The Corporation expects to incur abandonment and reclamation costs on 341 (205.6 net) wells, comprising currently producing and non-producing wells. As at December 31, 2020 the Corporation has estimated its share of the future abandonment and reclamation costs for its existing wells and facilities to be \$42.8 million undiscounted (approximately \$12.5 million discounted at 10%), of which the Corporation expects to spend approximately \$3.3 million undiscounted over the next three financial years. Of the undiscounted future abandonment and reclamation costs to be incurred over the life of the Corporation's proved developed producing reserves, approximately \$12.8 million has been deducted in estimating the future net revenue in the GLJ Report. For total proved plus probable reserves, approximately \$26.9 million of undiscounted future abandonment and reclamation costs has been deducted in estimating the future net revenue in the GLJ Report, which represents the Corporation's total existing estimated abandonment and reclamation costs associated with the developed reserves, plus all forecast estimates of abandonment and reclamation costs attributable to future development activity associated with the undeveloped reserves. In the GLJ Report, abandonment and reclamation costs have been included only for wells with reserves assigned. Abandonment and reclamation costs for suspended wells with no reserves assigned, service wells, gathering systems, facilities and surface land have not been included in the GLJ Report but are included in the Corporation's estimate of future abandonment and reclamation costs. The Corporation does not anticipate any unusually high expected development costs or operating costs in respect of its reserves.

Future Development Costs (Forecast Prices and Costs)

(\$ 000's)		
Period	Proved Reserves	Proved Plus Probable Reserves
2021	31,015	31,015
2022	50,084	55,074
2023	30,623	45,020
2024	50,339	36,337
2025	33,528	36,767
Remainder	9,621	181,347
Total for all years undiscounted	205,210	385,867
Total for all years discounted at 10% per year	160,171	251,511

On an on-going basis, Distinction typically uses its internally generated cash flow, proceeds from dispositions, available credit facilities and new equity and debt financings, if available on favourable terms, to fund requirements for future development required to develop the proved or the proved plus probable reserves. Distinction evaluates the available financing alternatives closely and has made use of all of the foregoing options depending on the given investment situation and the capital markets. Distinction expects to continue to use all financing alternatives available to continue pursuing its development strategy. The various financing alternatives have certain inherent costs which are considered in the economic evaluation of pursuing any development opportunity.

There can be no guarantee that funds will be available or that Distinction will allocate funding to develop all of the reserves attributed in the GLJ Report. Failure to develop those reserves would have a negative impact on future production and cash flow and could result in negative revisions to reserves.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the available funding sources. The Corporation does not anticipate that interest or other external funding costs would make further development of a property uneconomic for the Corporation.

Other Oil and Gas Information

Areas of Operations

Distinction's core operating area, Bigstone, is in the Deep Basin of Northwest Alberta. The stacked, multi-zone opportunities containing liquid rich natural gas and oil make it an attractive area in the industry. The area is also extensively covered by the infrastructure required to bring hydrocarbon products to market.

Bigstone Montney

The liquids-rich Montney development project is located in the Bigstone area of Alberta, 150 kilometres southeast of Grande Prairie. The Montney formation is recognized as one of the world's greatest deposits of hydrocarbons. It covers vast distances and many areas are now exploited with horizontal drilling combined with hydraulic fracturing. As the dataset of Montney production expands, a divergence between higher and lower economic value areas becomes apparent. Distinction's Bigstone Montney has the combination of high deliverability, high liquid-gas ratios and access to markets that make it a higher value area. As of December 31, 2020, Distinction had a working interest in a total of 117 (76 net) sections of

undeveloped and partially undeveloped land as part of 147 (97 net) sections of total land prospective for liquids-rich gas in the Montney formation.

The majority of production from the Montney is produced through the Corporation's 65 percent owned 07-11-060-23 W5M ("7-11 facility") compression and dehydration facility. The 7-11 facility includes an amine facility that is designed to sweeten up to 17 Mmcfd gross (11.1 Mmcfd net) of raw natural gas that can then be further processed at the Bigstone sweet natural gas plant in which the Corporation owns 25 percent. In 2020, Distinction spent \$0.5 million on building a pump station and other required infrastructure at its 7-11 facility to tie into a third party field condensate pipeline. The third party pipeline transports the majority of the Corporation's field condensate to a sales point in Fox Creek, Alberta, eliminating the majority of field condensate trucking costs.

Approximately 50% of Distinction's Montney gas was processed at the Energy Transfer Kaybob South 3 processing plant ("K3 plant") in 2020 and the remaining Montney gas, that is sweetened through the amine facility, was processed at Bigstone gas plant, with a gross capacity of 85 Mmcfd, which the Corporation has 25 percent working interest in. Natural gas processed at K3 plant is sold into the Chicago market via Distinction's full-path firm service with Alliance Pipeline Ltd. ("Alliance"). Natural gas processed at Bigstone gas plant is currently shipped on the Nova Gas Transmission system ("NGTL") and sold into the AECO market prior to an Alliance Pipeline lateral that is expected to be reactivated in 2022.

Bigstone Cretaceous (Sweet)

The sweet natural gas production from the shallower Cretaceous zones at Bigstone is the Corporation's second largest producing asset, contributing an average of 674 boe/d of production in 2020, with 14 percent as oil and natural gas liquids. Of this, fuel gas of 745mcf/d (124 boe/d) is allocated for the facility operations, resulting in net average daily production of 550 boe/d. In addition to the ownership in the Bigstone gas plant, the Corporation has over 40 kilometres of field gathering infrastructure as well as a 100 percent working interest in a 15 Mmcfd sweet shallow cut natural gas processing plant at West Bigstone.

Oil and Gas Properties and Wells (All Onshore)

The following table sets forth the number and status of wells in which Distinction had a working interest as at December 31, 2020. Distinction has title to its net working interest in all wells and is not subject to any change in ownership as a consequence of any current contract or agreement.

	Producing Wells				Non-Producing Wells			
	Oil		Gas		Oil		Gas	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾
Alberta	3	2.3	121	94.8	15	13.6	164	76.0
British Columbia	-	-	-	-	-	-	38	18.9
	3	2.3	121	94.8	15	13.6	202	94.9

Of the 217 (108.5 net) non-producing wells, 100 (47.4 net) have been abandoned and 42 (22.1 net) have had zonal abandonments.

Distinction does not have any properties to which reserves have been attributed and which are capable of producing, but which are not producing.

Properties with No Attributed Reserves

The following table sets forth the Corporation's unproved land holdings as at December 31, 2020.

(Acres)	Unproved	
	Gross⁽¹⁾	Net⁽²⁾
Alberta	89,062	46,759
British Columbia	30,108	12,237
Total	119,170	58,996

During 2021, approximately 28,450 net acres of the Corporation's land is set to expire, however Distinction expects that, subject to Crown approval, approximately 65% of these lands will be continued.

None of the above properties are subject to any work commitments.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

There are several economic factors and significant uncertainties that affect Distinction's anticipated development of its properties to which no reserves are attributed. Distinction will be required to make substantial capital expenditures in order to prove, exploit, develop and produce from these properties in the future. If cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain opportunities and reduce or terminate its operations on such properties. The inability of Distinction to access sufficient capital for its exploration and development purposes could have a material adverse effect on the Corporation's ability to execute its business strategy to develop these prospects.

The primary economic factors that affect the development of the properties to which no reserves have been attributed are future commodity prices for oil, natural gas and NGLs (and the Corporation's outlook relating to such prices) and the future costs of drilling, completing, tying-in and operating wells at the time that such activities are considered. The Corporation would also need to secure adequate transportation capacity on acceptable terms for its incremental future production. The primary uncertainties that affect the development of such lands are the future drilling and completion results achieved in the development activities, drilling and completion results achieved by others on lands in close proximity to these lands, and future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities. All of these uncertainties have the potential to delay the development of such lands. Conversely, uncertainty as to the timing and nature of the evolution or development of better exploration, drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to such properties.

Forward Contracts

Distinction uses risk management contracts in order to reduce its exposure to fluctuations in commodity prices. These instruments are not used for trading or speculative purposes.

All of the contracts through which the Corporation has fixed the price applicable to certain of its future production outstanding as at December 31, 2020 have been disclosed in Note 6 to the audited financial

statements of the Corporation for the years ended December 31, 2020 and 2019, which are available on the SEDAR website at www.sedar.com.

Distinction has an agreement with Alliance for full path service to deliver up to 29.7 Mmcfd of natural gas volumes until October 2025 into the Chicago gas market. In addition, the Corporation has service on NGTL until March 2026. The Corporation's transportation commitments with Alliance and NGTL exceed Distinction's current expected future production from its total proved reserves. Although the Corporation's Montney production is currently being shipped on both Alliance (K3 plant) and NGTL (Bigstone gas plant), the Corporation expects to ship the majority of its Bigstone Montney production on Alliance after an Alliance lateral from Bigstone gas plant is reactivated in 2022. Based on this and the gas production from total proved reserves in the GLJ Report, the total cost of the excess transportation capacity on Alliance and NGTL is estimated to be approximately \$20.6 million for the term of these services. In order to mitigate the cost of transportation service in excess of its needs, the Corporation temporarily assigns the excess service to other shippers or purchases natural gas in Alberta or British Columbia for sale in Chicago. The company has already mitigated approximately \$3.1 million in excess Alliance transportation for 2021 by temporarily assigning approximately 17 Mmcfd until November 1, 2021.

Tax Horizon

The income taxes deducted in the calculation of future net revenue assume a scenario whereby the Corporation produces all of its existing proved plus probable reserves. Under this scenario, Distinction would pay taxes in 2027.

The Corporation forecasts its tax horizon assuming reinvestment of cash flow to achieve production and reserve growth. The Corporation does not expect to be required to pay income taxes for the 2020 financial year. The Corporation does not anticipate becoming cash taxable before 2027. This estimate will be impacted by, among other factors, production volumes, commodity prices, foreign exchange rates, operating costs, interest rates, changes in tax laws and Distinction's other business activities. Changes in these factors from estimates used by the Corporation could result in Distinction paying income taxes earlier than expected.

Costs Incurred

During 2020, the Corporation incurred the following costs in Canada:

	2020 <i>(\$ 000's)</i>
Property and acquisition costs – Unproved properties	-
Property and acquisition costs – Proved properties	-
Exploration costs ⁽¹²⁾	-
Development costs ⁽¹⁰⁾	<u>23,047</u>

Exploration and Development Activities

The following table sets forth the number of completed exploratory and development wells in which Distinction participated which were drilled during the year ended December 31, 2020:

	Exploratory Wells ⁽¹¹⁾		Development Wells ⁽⁹⁾	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾
Natural gas wells	-	-	3.0	3.0
Total wells	-	-	3.0	3.0

1) Distinction did not drill any dry holes or stratigraphic test wells for the year ended December 31, 2020.

Distinction's capital program for 2020 was focused on the delineation and development of its inventory of opportunities at Bigstone in the Montney formation. The Corporation expects to continue to develop and delineate the Bigstone Montney asset as part of its capital program in 2021.

Production Estimates

The following table sets forth the volume of daily gross⁽¹⁾ production estimated for the year 2021 in the reserves forecast for proved, probable and proved plus probable reserves.

Proved

	Conventional natural gas (mcf/d)	Shale gas (mcf/d)	Natural gas liquids (bbls/d)	Total (boe/d)
Bigstone Montney	-	20,624	2,554	5,992
Bigstone Sweet	2,990	-	94	592
Other	10	-	-	2
Total Proved	3,000	20,624	2,648	6,585

Probable

	Conventional natural gas (mcf/d)	Shale gas (mcf/d)	Natural gas liquids (bbls/d)	Total (boe/d)
Bigstone Montney	-	704	355	473
Bigstone Sweet	71	-	2	14
Other	-	-	-	-
Total Probable	71	704	358	487

Proved plus Probable

	Conventional natural gas (mcf/d)	Shale gas (mcf/d)	Natural gas liquids (bbls/d)	Total (boe/d)
Bigstone Montney	-	21,329	2,909	6,464
Bigstone Sweet	3,061	-	96	606
Other	10	-	-	2
Total Proved plus Probable	3,071	21,329	3,006	7,072

Production History

Distinction's 2020 average daily production, before deduction of royalties, is summarized below:

Average Daily Production	Quarter Ended				Year Ended December 31, 2020
	March 31, 2020	June 30, 2020	September 30, 2020	December 31, 2020	
Conventional natural gas (mcf/d)	2,519	2,545	2,724	3,189	2,722
Shale gas (mcf/d)	21,082	18,352	19,076	19,502	19,525
Natural gas liquids (bbls/d)	2,641	3,140	3,002	3,009	2,949
Total (boe/d)	6,575	6,623	6,635	6,791	6,657

Distinction's 2020 share of average daily production, before deduction of royalties, from Bigstone Montney is summarized below:

Average Daily Production	Quarter Ended				Year Ended December 31, 2020
	March 31, 2020	June 30, 2020	September 30, 2020	December 31, 2020	
Shale gas (mcf/d)	21,082	18,352	19,076	19,502	19,525
Natural gas liquids (bbls/d)	2,523	3,050	2,914	2,914	2,851
Total (boe/d)	6,037	6,109	6,093	6,164	6,105

Distinction's 2020 share of average daily production, before deduction of royalties, from Bigstone Sweet is summarized below:

Average Daily Production	Quarter Ended				Year Ended December 31, 2020
	March 31, 2020	June 30, 2020	September 30, 2020	December 31, 2020	
Conventional natural gas (mcf/d)	2,508	2,534	2,723	3,185	2,715
Natural gas liquids (bbls/d)	117	89	88	95	97
Total (boe/d)	535	511	542	626	550

Netback By Product

The following table sets forth information in respect of quarterly average net product prices received before risk management contracts, royalties paid, operating expenses and operating netbacks by product for the year ended December 31, 2020.

Conventional Natural Gas (\$/mcf)				
Quarter Ended				
	March 31, 2020	June 30, 2020	September 30, 2020	December 31, 2020
Average prices received	2.06	2.43	2.87	2.81
Royalties	0.81	0.08	0.05	0.04
Operating expenses	(2.39)	(3.37)	(1.38)	(2.79)
Transportation	(0.22)	(0.19)	(0.27)	(0.26)
Netback	0.26	(1.05)	1.27	(0.20)

Shale Gas (\$/mcf)				
Quarter Ended				
	March 31, 2020	June 30, 2020	September 30, 2020	December 31, 2020
Average prices received	2.40	2.08	2.40	2.90
Royalties	(0.01)	(0.16)	(0.25)	(0.27)
Operating expenses	(2.87)	(2.27)	(2.08)	(2.48)
Transportation	(0.83)	(0.80)	(0.79)	(0.90)
Netback	(1.31)	(1.15)	(0.72)	(0.75)

Natural Gas Liquids (\$/bbl)				
Quarter Ended				
	March 31, 2020	June 30, 2020	September 30, 2020	December 31, 2020
Average prices received	38.15	18.44	39.11	39.74
Royalties	(5.33)	(2.19)	(3.62)	(4.30)
Operating expenses ¹	-	-	-	-
Transportation	(2.90)	(3.33)	(2.44)	(2.78)
Netback	29.92	12.92	33.05	32.66

- 1 The Corporation does not allocate operating expenses to natural gas liquids as they are a by-product of conventional natural gas and shale gas.

Product Sales Revenues

The only significant products produced and sold by the Corporation are conventional natural gas, shale gas and natural gas liquids. Virtually all of these products are sold on a short term basis that is a function of current market prices. None of the Corporation's products are sold to non-arm's length parties.

The following table summarizes the Corporation's revenues in 2020 and 2019 by product type.

Product (\$ 000's)	2020	2019
Conventional natural gas	2,458	1,633
Shale gas	17,670	27,209
Natural gas liquids	36,246	64,040

APPENDIX A

ABBREVIATIONS, EQUIVALENCIES AND DEFINITIONS

The following are abbreviations of terms used in this form. All calculations converting natural gas to crude oil equivalent have been made using a ratio of 6 mcf of natural gas to one barrel of crude equivalent.

Crude Oil and Natural Gas Liquids		Natural Gas	
bbl	One barrel equaling 34.972 Imperial gallons or 42 U.S. gallons	bcf	Billion cubic feet
bbls/d	Barrels per day	bcfe	Billion cubic feet equivalent
bbls/mmcf	Barrels per million cubic feet	bcf/d	Billion cubic feet per day
boe	Barrels of oil equivalent	mcf	Thousand cubic feet
boe/d	Barrels of oil equivalent per day	Mcfe	Thousand cubic feet equivalent
Mboe	Thousand barrels of oil equivalent	mcf/d	Thousand cubic feet per day
Mmboe	Million barrels of oil equivalent	Mmcfe	Million cubic feet equivalent
Mbbls	Thousand barrels	Mmcf	Million cubic feet
Mmbbls	Million barrels	Mmcf/d	Million cubic feet per day
Mmlts	Million long tonnes	Mmbtu	Million British Thermal Units
NGL or NGLs	Natural gas liquids, consisting of any one or more of propane, butane and condensate	GJ/d	Gigajoules per day
WI	Working interest	US\$	United States dollar
		Cdn\$	Canadian dollar

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

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471
GJ	Mcf	1.055

The following are the note references to the tables disclosed under “Oil and Gas Activities” in this NI51 101F1 disclosure.

(1) **Gross**

- (a) In relation to the Corporation's interest in production or reserves, its “company gross reserves”, which are the Corporation’s working interest (operating or non-operating) share before deduction of royalties and excluding any royalty interest of the Corporation;
- (b) In relation to wells, the total number of wells in which the Corporation has an interest;
- (c) In relation to properties, the total area of properties in which the Corporation has an interest.

(2) **Net**

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

(3) Definitions used for reserve categories in the GLJ Report are as set forth, which definitions apply to both estimates of individual reserves entities and the aggregate of reserves for multiple entities:

Reserve Categories

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions,

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

- (a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- (b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

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

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

- i. **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These

reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

- ii. **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

- (5) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned. In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

- (6) **Levels of Certainty for Reported Reserves**

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

- (a) At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- (b) At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

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

- (7) **Forecast prices and costs**

Future prices and costs that are:

- (a) Generally accepted as being a reasonable outlook of the future;
- (b) If, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast summary table identifies benchmark reference pricing that apply to the Corporation.

- (8) **Future income tax expenses**
Future income tax expenses are estimated:
- (a) Making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;
 - (b) Without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;
 - (c) Taking into account estimated tax credits and allowances (for example, royalty tax credits); and
 - (d) Applying to the future pre-tax net cash flows relating to the Corporation's oil and gas activities the appropriate year-end statutory rates, taking into account future tax rates already legislated.
- (9) **Development well** – A well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.
- (10) **Development costs** – Costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:
- (a) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;
 - (b) Drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;
 - (c) Acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
 - (d) Provide improved recovery systems.
- (11) **Exploration well** – A well that is not a development well, a service well or a stratigraphic test well.
- (12) **Exploration costs** – Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as “prospecting costs”) and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities are:
- (a) Costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as “geological and geophysical costs”);
 - (b) Costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defense, and the maintenance of land and lease records;
 - (c) Dry hole contributions and bottom hole contributions;
 - (d) Costs of drilling and equipping exploratory wells; and

- (e) Costs of drilling exploratory type stratigraphic test wells.
- (13) Numbers may not add due to rounding.