Q. Please provide the most recent DBRS (or other rating agency) full credit rating report for each Crown-owned electrical corporation listed in PUB-Nalcor-251, similar to the Newfoundland Hydro DBRS reports in the response to PUB-Nalcor-213.

A. Please find attached the most recent DBRS reports:

- PUB-Nalcor-252, Attachment 1: British Columbia Hydro and Power Authority;
- PUB-Nalcor-252, Attachment 2: Hydro-Québec;
- PUB-Nalcor-252, Attachment 3: Ontario Power Generation Inc.;
- PUB-Nalcor-252, Attachment 4: Saskatchewan Power Corporation; and
- PUB-Nalcor-252, Attachment 5: Manitoba Hydro-Electric Board.

DBRS does not complete a ratings report for New Brunswick Power.

Rating Report

British Columbia Hydro and Power Authority

DBRS

Insight beyond the rating.

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Ratings

Debt	Rating	Trend
Long-Term Obligations (bsd on Prov of BC)*	AA (high)	Stable
Short-Term Obligations (bsd on Prov of BC)*	R-1 (high)	Stable

* These obligations are based on the status of BC Hydro as a Crown agent of the Province and reflect the Province's debt ratings. The rating assigned to the Long-Term Obligations is also applicable to $10 million of debt issued by BC Hydro and guaranteed by the Province.

Rating Update

DBRS Limited (DBRS) updated its report on British Columbia Hydro and Power Authority (BC Hydro or the Utility). The Utility's ratings are a flow-through of the ratings on the Province of British Columbia (the Province; rated AA (high) and R-1 (high) with Stable trends by DBRS; see DBRS's report on the Province dated April 2, 2018). Pursuant to the B.C. *Hydro and Power Authority Act*, BC Hydro's Long- and Short-Term Obligations are either direct obligations of, or are guaranteed by, the Province. Please see DBRS's *Rating Canadian Provincial Agents of the Crown* methodology for further details. DBRS considers BC Hydro to be self-supporting as it is able to fund its own operations and service its debt obligations.

On March 1, 2018, the British Columbia Utilities Commission (BCUC) issued its decision and order on BC Hydro's F2017 to F2019 Revenue Requirements Application. In its decision, the BCUC approved rate increases of 4.0%, 3.5% and 3.0% effective April 1 of 2016, 2017 and 2018, respectively. DBRS views the decision as positive for the Utility's financial profile and key ratios as the rate increases are expected to help provide cash flows needed to fund the significant ongoing capital expenditures (capex) program, including the $10.7 billion Site C Clean Energy project (Site C). DBRS also views the BCUC's decision not to approve BC Hydro's amended request of a 0% rate increase for F2019 as positive. While any foregone revenues as a result of the applied-for rate freeze would have been deferred and recovered through future rates, the rate freeze would likely have put additional pressure on cash flow metrics in F2019.

In June 2018, the Province announced that it would conduct a comprehensive review of BC Hydro. Phase one of the review, which is expected to be completed in early 2019, will conclude in a refreshed rates forecast (the Forecast) and inform the Utility's next Revenue Requirements Application. The Province has indicated that the focus of the Forecast will be reducing growth in rates and ensuring that BC Hydro has sound financial and regulatory oversight. DBRS viewed the current Ten Year-Rates Plan as positive for the Utility as initiatives, such as reducing dividends until leverage reaches 60% from the current level of 80% and eliminating Tier 3 water rental rates (which represent savings of $50 million annually), would help strengthen its financial ratios. DBRS will review how the Forecast will impact BC Hydro's financial profile going forward once it is available. Phase two of the review, which will not begin until phase one is concluded, will address trends in the utilities sector, including technological advancements and climate action, and how BC Hydro will tackle these changes.

Financial Information

	12 mos. September 30	For the year ended March 31				
	2018	**2018**	**2017**	**2016**	**2015**	**2014**
Total debt in capital structure 1	81.0%	79.8%	81.0%	81.2%	81.2%	81.4%
Cash flow/Total debt 1	7.5%	8.6%	7.1%	8.6%	7.8%	7.7%
EBIT gross interest coverage (times) 1	1.58	1.66	1.43	1.77	1.60	1.50

1 Including operating leases.

Issuer Description

BC Hydro is a commercial Crown agent of the Province which generates, transmits and distributes electric power, primarily from renewable energy sources. Apart from providing electricity to British Columbia, BC Hydro's transmission system is also connected to transmission systems in the Province of Alberta and Washington State, allowing energy-trade opportunities.

Rating Considerations

Strengths

1. All debt is held/guaranteed by the Province
The Utility's Long- and Short-Term Obligations are either direct obligations of, or are guaranteed by, the Province; thus, the ratings on the Utility are a flow-through of the ratings on the Province.

2. Sizable and low-cost hydroelectric generation
BC Hydro has an installed capacity of 12,427 megawatts (MW) after the Waneta Dam and Generating Station transaction, over 98% of which is in the form of low-cost hydroelectric generation, making the Utility a very competitive source of power generation. This, coupled with its water-storage capacity, allows BC Hydro to optimize market purchases to meet its load obligations and, through its interconnections with the United States and Alberta, export power during on-peak hours and import power during off-peak hours.

3. Reasonable regulatory environment
BC Hydro currently operates under a cost-of-service (COS) regulation prescribed by the BCUC that allows the Utility to recover all prudent expenses. Per Order in Council (OIC) 590, BC Hydro's net income has been set at $684 million for F2017, $698 million for F2018, and $712 million for F2019 and beyond. DBRS views this rate-setting regulation as reasonable and should only have a modest impact on the Utility's earnings profile going forward. DBRS notes that a comprehensive review of BC Hydro is ongoing with phase one aimed at developing a refresh plan for rates. A report is expected to be released in early 2019 ahead of the next Revenue Requirements Application to be filed in February 2019.

Challenges

1. High leverage
BC Hydro has a high debt level with leverage at 81.0% of its total capital as at September 30, 2018. As with most government-owned and government-supported utilities, the Utility's high leverage ratio is not unusual, given the provincial support it receives. DBRS notes that the Province's Ten Year-Rates Plan for BC Hydro includes the reduction of dividends to the Province after F2017 with dividends forecast to be reduced to $0 in F2020 and to remain at $0 until the Utility's debt-to-equity ratio reaches 60:40. DBRS expects recommendations from the comprehensive review to continue to support BC Hydro's deleveraging plan.

2. Large planned capital spending
The Utility has forecast gross capex of approximately $3.7 billion for F2019, $2.9 billion for F2020 and $3.1 billion for F2021. The increase in capex during this period is largely because of Site C. The project, which has a targeted in-service date of 2024 (when all units will be in service), had an original cost estimate of $8.8 billion, including a $440 million project reserve. The BCUC noted that the project cost could exceed $10.0 billion. On December 11, 2017, the Province announced a decision to continue Site C with an updated project cost estimate of $10.7 billion, including a $700 million project reserve.

3. Hydrology risk
Since over 90% of BC Hydro's generating capacity is hydro-based, cash flows are sensitive to hydrological conditions; however, hydrology risk is mitigated by its climatologically disparate drainage basins and substantial reservoir storage capacity.

Earnings and Outlook

	12 mos. September 30	For the year ended March 31				
(CAD millions where applicable)	**2018**	**2018**	**2017**	**2016**	**2015**	**2014**
Domestic revenue	5,646	5,527	5,199	5,056	4,829	4,319
Trading revenue	808	710	675	601	919	1,073
Total revenues 1	**6,495**	**6,317**	**5,670**	**5,732**	**5,695**	**5,353**
Net sales	4,081	4,050	3,576	3,880	3,492	3,207
EBITDA	2,697	2,684	2,317	2,723	2,365	2,103
EBIT	1,392	1,417	1,085	1,482	1,160	1,108
Gross interest expense	902	873	792	865	762	777
Net income before non-recurring items	707	756	472	722	521	504
Reported net income	674	684	684	655	581	549
Return on equity	13.5%	14.6%	10.0%	16.7%	13.0%	13.7%

1 Revenues adjusted for unrealized gains and losses on financial instruments.

F2018 Summary

- BC Hydro's earnings have been stable and predictable as the impact of non-controllable factors (e.g., level of water inflows, customer load, market prices for electricity and natural gas, weather temperatures, interest rates and foreign-exchange rates) on net income is largely mitigated by regulatory deferral accounts (see Regulation section below).
- Reported net income for the Utility in F2018 was the same as in F2017 and slightly below the $698 million set by the Province.
  - Revenues benefited from a 3.5% rate increase effective April 1, 2017. This was offset by (1) higher energy costs, (2) higher operating costs and (3) higher depreciation and interest expense related to the significant capex program.

F2019 Outlook

- BC Hydro has forecast net income of $712 million for F2019 which matches the allowed net income per OIC 590.
  - The BCUC approved a 3.0% increase in rates for the Utility effective April 1, 2018.
- The Province is currently undergoing a comprehensive review of BC Hydro.
  - The first phase is focused on the Utility's costs and rates. This will result in a refreshed Forecast for BC Hydro as it prepares its next Revenue Requirements Application for February 2019.
  - The second phase will focus on the changing energy market and help the Utility develop its Integrated Resource Plan (IRP).

Financial Profile

	12 mos. September 30	For the year ended March 31				
(CAD millions where applicable)	2018	2018	2017	2016	2015	2014
Net income before non-recurring items	707	756	472	722	521	504
Depreciation & amortization	845	830	783	745	691	643
Other non-cash operating items	201	248	233	193	187	147
Cash flow from operations	**1,753**	**1,834**	**1,488**	**1,660**	**1,399**	**1,294**
Payments to the Province	(159)	0	(585)	(264)	(167)	(215)
Capital expenditures	(2,307)	(2,008)	(2,403)	(2,004)	(1,839)	(1,803)
Free cash flow (bef. working cap. changes)	**(713)**	**(174)**	**(1,500)**	**(608)**	**(607)**	**(724)**
Changes in non-cash work. cap. items	(396)	(366)	(582)	(223)	264	(354)
Change in regulatory accounts 1	323	142	311	(475)	(734)	(265)
Net free cash flow	**(786)**	**(398)**	**(1,771)**	**(1,306)**	**(1,077)**	**(1,343)**
Acquisitions & long-term investments	(1,219)	0	0	0	0	0
Net equity change	0	0	0	0	0	0
Net debt change	2,040	329	1,803	1,325	1,026	1,490
Other financing	72	62	(27)	(14)	(17)	(100)
Change in cash	**107**	**(7)**	**5**	**5**	**(68)**	**47**
Total debt	22,943	21,029	20,243	18,453	17,135	15,973
Cash and equivalents	172	42	49	44	39	107
Total debt in capital structure 2	81.0%	79.8%	81.0%	81.2%	81.2%	81.4%
Cash flow/Total debt 2	7.5%	8.6%	7.1%	8.6%	7.8%	7.7%
EBIT gross interest coverage (times) 2	1.58	1.66	1.43	1.77	1.60	1.50
Dividend payout ratio	22.5%	0.0%	123.9%	36.6%	32.1%	42.7%

1 Regulatory asset transfers adjusted from cash flow from operations. 2 Including operating leases.

F2018 Summary

- BC Hydro's key financial ratios strengthened modestly in F2018 largely because of higher cash flow from operations, which increased because of higher average customer rates and higher consumption.
- Gross capex for the year increased slightly to approximately $2.5 billion as the Utility continued work on Site C ($705 million).
- As per OIC 095, beginning in F2018, distributions from BC Hydro to the Province will be reduced by $100 million annually until they reach $0 and will remain at $0 until the Utility's debt-to-equity ratio reaches 60:40.
  - For F2018, BC Hydro has paid $159 million to the Province.
- Changes in regulatory accounts included: (1) $203 million reduction in the energy deferral accounts; (2) $123 million reduction to the non-current pension cost regulatory account because of a 50% reduction in Medical Service Plan premiums; (3) $90 million addition to the IFRS property, plant and equipment regulatory account to smooth the capitalization of overhead costs under IFRS; (4) $327 million addition to the rate-smoothing regulatory account to mitigate the impact of rate increases in the Ten Year-Rates Plan; and (5) $82 million addition to the demand-side management regulatory account for planned energy conservation spending.
- The net free cash flow deficit was funded through incremental debt from the Province.

F2019 Outlook

- Cash flow for F2019 is expected to see a modest increase, benefiting from the planned rate increase for the year.
- BC Hydro forecasts gross capex of $3.7 billion for F2019, including $899 million for Site C.
  - In July 2018, the Utility also acquired the remaining two-thirds interest in the Waneta Dam and Generating Station for $1.2 billion.
- DBRS expects BC Hydro to fund any free cash flow deficits from elevated capex and acquisitions with additional debt issuances.
  - For F2019, BC Hydro has accrued $59 million to distribute to the Province.
- Under the Province's Ten Year-Rates Plan for BC Hydro, the Utility is expected to delever by increasing operating cash flows from a growing equity base and reducing dividend payments to the Province.

Liquidity and Debt Profile

Liquidity

- BC Hydro's liquidity remains sufficient to fund its ongoing operations and capital investments.
- The Utility has a $4.5 billion commercial paper program with the Province, which is included in the revolving borrowings (approximately $2.0 billion outstanding as at September 30, 2018).

Upcoming Debt Maturity	FY2019	FY2020	FY2021	FY2022	FY2023	Thereafter	Total
(CAD millions as at March 31, 2018)	1,288	175	1,100	526	500	16,859	**20,448**
	6.3%	**0.9%**	**5.4%**	**2.6%**	**2.4%**	**82.4%**	**100.0%**

- BC Hydro has a well-distributed, long-term debt maturity schedule with 20% of total long-term debt expected to mature over the next five years.
- The Utility issued approximately $1.2 billion (par value) of long-term debt in F2018 and redeemed $40 million of bonds.
  - BC Hydro issued an additional $2,450 million (par value) of long-term debt in the first six months of F2019 and redeemed $457 million of bonds.
- All debt is either held or guaranteed by the Province.
- The Utility reduced a majority of its U.S. debt payment sensitivity through cross-currency swaps. The net U.S.-dollar revenue generated from electricity trades through Powerex Corp. (Powerex) also acts as a natural hedge against the BC Hydro's U.S.-dollar expenditures.

Description of Operations

Core Business

- BC Hydro is the largest electric utility in British Columbia with 30 hydroelectric facilities and two thermal generating plants. The Utility has 12,427 MW of installed generating capacity.
- The Utility remains one of the lowest-cost utility producers in Canada.
- It delivers electricity through a network of approximately 79,528 kilometres of transmission and distribution lines.
- Apart from providing electricity to the Province, the Utility's transmission system is also connected to transmission systems in Alberta and Washington State, which improves the reliability of its system and provides opportunities for trade.

Powerex Corp.

- Powerex, a wholly owned subsidiary of BC Hydro, is a key participant in energy markets across North America, buying and supplying wholesale power, renewable energy, natural gas, ancillary services as well as financial energy products and services.
- Powerex's trade activities help BC Hydro to balance its system by importing energy to meet domestic demand when there is a supply shortage in the system caused by factors such as lower water inflows. Exports are made only after ensuring that domestic demand requirements can be met.

Other Subsidiaries

- Powertech Labs Inc.
- BCHPA Captive Insurance Company Ltd.
- Columbia Hydro Constructors Ltd. and
- Tongass Power and Light Company.

Province of British Columbia

(Excerpt from the DBRS Rating Report dated April 2, 2018. Please see the report for more details.)
DBRS Limited (DBRS) confirmed the Issuer Rating, Long-Term Debt rating and Renminbi Bonds rating of the Province of British Columbia (B.C. or the Province) at AA (high) as well as the Short-Term Debt rating at R-1 (high). All trends are Stable. The ratings remain well supported by the Province's diverse and growing economy, positive budget outlook, ample fiscal capacity and low debt burden.

Regulation

- BC Hydro is fully regulated by the BCUC, a regulatory agency of the provincial government, which operates under and administers the Utilities Commission Act.
- The BCUC reviews and approves BC Hydro's calculations of revenue requirements as well as deferral and regulatory accounts as the BCUC must ensure that the rates are sufficient to allow the Utility to provide reliable electricity service, meet its financial obligations and comply with government policy.
  - To assist BC Hydro cash flows under the Ten Year-Rates Plan, the government has established longer-term flat net-income targets through regulation and declining dividends to provide certainty and stability for the Utility's annual rate setting.
- Approval of rates is based on the assessment of BC Hydro's Revenue Requirements Applications through the COS method.
- Deferral and regulatory accounts allow the Utility to defer certain types of revenue and cost variances through transfers to and from the accounts, which helps to smooth the overall effect of revenue and cost volatility on ratepayers and to better match costs and benefits for different generations of customers.
- The Province released a Ten Year-Rates Plan for BC Hydro in November 2013. The plan called for the following:
  - Rate increases of 9.0% and 6.0% for F2015 and F2016, respectively. The BCUC will be responsible for setting rate increases within a cap of 4.0% for F2017, 3.5% for F2018 and 3.0% for F2019.
  - A reduction in dividends beginning in F2018 with dividends forecast to be eliminated in F2020 and remain at $0 until the Utility's debt-to-equity ratio reaches 60:40.
- The Province issued Special Directions No. 6 and No. 7 in March 2014 for the BCUC with regard to the implementation of the Ten Year-Rates Plan for BC Hydro.
- The Province issued OIC 590 in July 2016, which set the Utility's net income at $684 million, $698 million and $712 million for F2017, F2018, F2019, respectively, and subsequent fiscal years.
- In July 2016, BC Hydro filed an application with the BCUC for rates in F2017, F2018 and F2019. Per the Ten Year-Rates Plan, the Utility applied for average rate increases of 4.0% in F2017, 3.5% in F2018 and 3.0% in F2019.
  - In February 2016, the BCUC approved an interim average rate increase of 4.0%, effective April 1, 2016.
  - In March 2017, the BCUC approved an interim average rate increase of 3.5%, effective April 1, 2017.
  - In November 2017, per a mandate letter from the Province, BC Hydro changed its requested rate increase for F2019 to 0%.
  - On March 1, 2018, the BCUC issued its decision and order on the Utility's F2017 to F2019 Revenue Requirements Application, approving final rate increases of 4.0%, 3.5% and 3.0% effective April 1 of 2016, 2017 and 2018, respectively.
- In August 2017, the Province issued OIC 244 requesting an inquiry led by the BCUC on the implications of (1) completing Site C as planned, (2) suspending the project while maintaining the option to resume construction until 2024 and (3) terminating construction and remediating the site. The Province also asked the BCUC if the project was currently on time and on budget, the costs of suspending or terminating the project for ratepayers and potential mechanisms to recover those costs as well as whether any other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits to ratepayers at similar or lower unit energy costs as the project. The BCUC was not tasked with providing a recommendation on which option the Province should pursue.
  - The BCUC delivered a final report on November 1, 2017, finding that (1) suspending Site C was the riskiest and most costly scenario, (2) the project was not on target for completion in 2024 and (3) costs may exceed $10.0 billion; however, in several areas, the BCUC report was inconclusive in its findings.
  - On December 11, 2017, the Province announced that BC Hydro will continue construction on Site C. In its announcement, the Province noted that the budget for the project has been revised to $10.0 billion (excluding $700 million of reserves), but will continue to target an in-service date of 2024. The Province will also establish a Project Assurance Board to provide additional oversight on Site C to ensure that the project is completed on time and within budget.
- In June 2018, the Province also announced a comprehensive review of BC Hydro.
  - The first phase of the review focuses on the Utility's costs and rates by developing a new Forecast and reducing the growth in rates as well as ensuring BC Hydro has sound financial and regulatory oversight. The review will also inform the next Revenue Requirements Application to be filed in February 2019. A report on the first phase is expected in early 2019.
  - The second phase of the review will address trends in the utility sector, including technological advancements and climate action, and how BC Hydro will tackle these changes. This will also help the Utility develop its next IRP.

Assessment of BC Hydro's Regulatory Environment

The chart below reflects DBRS's assessment of the regulatory environment for BC Hydro based on DBRS's methodology guideline.

Criteria	Score	Analysis
(1) Deemed Equity	Excellent Good Satisfactory Below Average Poor	N/A – Beginning in F2017, the concept of deemed equity is irrelevant as, in lieu of declining dividends to assist BC Hydro cash flows under the Ten Year-Rates Plan, the Province has established longer-term flat net-income targets through regulation to provide certainty and stability for BC Hydro's annual rate setting.
(2) Allowed ROE	Excellent Good Satisfactory Below Average Poor	N/A – The concept of allowed ROE is irrelevant for the Utility as an allowed net income has been set by the Province for F2017 and subsequent fiscal years.
(3) Energy Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	Energy costs are fully passed through to the ratepayers. Since the majority of the energy is generated through hydroelectric facilities, power costs are relatively lower than in other jurisdictions.
(4) Capital and Operating Cost Recoveries	Excellent **Good** Satisfactory Below Average Poor	BC Hydro requires the BCUC to pre-approve large extensions to the Utility's system prior to construction. Capital costs are added to the rate base after it comes into service. The BCUC's use of future test years also helps reduce regulatory lag with regard to operating cost recovery. As well, volume risk is partly mitigated by the use of deferral and variance accounts.
(5) COS versus IRM	**Excellent** Good Satisfactory Below Average Poor	The BCUC handles rate making on a COS basis. The prudency test in the Province is rather rigid, resulting in some regulatory lag and disallowances of costs incurred by utilities. DBRS notes the BCUC has expressed interest in BC Hydro eventually moving to a performance based rate-setting mechanism.
(6) Political Interference	Excellent Good Satisfactory **Below Average** Poor	The Province plays a significant role in the electricity sector as it owns BC Hydro, which is the primary provider of power and electricity services in British Columbia. The electric utility regulator, the BCUC, operates as a quasi-judicial body. The BCUC's role in rate setting was reduced in recent years as the Province capped rate increases (to be set by the BCUC) for F2017 to F2019. The BCUC will set rates for F2020 to F2024.
(7) Stranded Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	Minimal stranded costs exist in the Province. BC Hydro also approved regulatory accounts for the purpose of cost recovery, which reduces the risk of stranded costs. DBRS notes that the risk of stranded costs associated with Site C has been significantly mitigated following the Province's decision to continue with the project.
(8) Rate Freeze	Excellent **Good** Satisfactory Below Average Poor	In November 2017, the Province announced a one-year rate freeze for BC Hydro rates effective April 1, 2018. The Province also announced that a comprehensive review of BC Hydro will be undertaken during this period to develop a refreshed plan for rates to keep electricity rates low and predictable over the long term. While the Utility amended its F2017 to F2019 revenue requirement applications to the BCUC by requesting a 0% increase in rates for F2019, this was not approved by the regulator.

British Columbia Hydro and Power Authority

(CAD millions)	September 30 2018	March 31 2018	March 31 2017
Assets			
Cash & equivalents	172	42	49
Accounts receivable	617	810	808
Inventories	204	144	185
Prepaid expenses & other	329	341	306
Total current assets	**1,322**	**1,337**	**1,348**
Net fixed assets	27,160	25,083	22,998
Intangible assets	587	591	601
Investments & others	6,498	6,731	6,941
Total assets	**35,567**	**33,742**	**31,888**

	September 30 2018	March 31 2018	March 31 2017
Liabilities & Equity			
S.T. borrowings	0	0	0
Accounts payable	1,468	1,621	1,190
Current portion L.T.D.	3,056	3,344	2,878
Other current liab.	42	112	60
Total current liab.	**4,566**	**5,077**	**4,128**
Long-term debt	19,887	17,685	17,365
Other L.T. liab.	5,592	5,524	5,486
Shareholders' equity	5,522	5,456	4,909
Total liab. & SE	**35,567**	**33,742**	**31,888**

	12 mos. September 30	For the year ended March 31				
Balance Sheet & Liquidity & Capital Ratios	**2018**	**2018**	**2017**	**2016**	**2015**	**2014**
Current ratio	0.29	0.26	0.33	0.27	0.21	0.26
Total debt in capital structure	80.6%	79.4%	80.5%	80.4%	80.4%	80.5%
Total debt in capital structure 1	81.0%	79.8%	81.0%	81.2%	81.2%	81.4%
Cash flow/Total debt	7.6%	8.7%	7.4%	9.0%	8.2%	8.1%
Cash flow/Total debt 1	7.5%	8.6%	7.1%	8.6%	7.8%	7.7%
(Cash flow-dividends)/Capex	0.69	0.91	0.38	0.70	0.67	0.60
Dividend payout ratio	22.5%	0.0%	123.9%	36.6%	32.1%	42.7%
Coverage Ratios (times)						
EBIT gross interest coverage	1.54	1.62	1.37	1.71	1.52	1.43
EBITDA gross interest coverage	2.99	3.07	2.93	3.15	3.10	2.71
Fixed-charge coverage	1.54	1.62	1.37	1.71	1.52	1.43
EBIT gross interest coverage 1	1.58	1.66	1.43	1.77	1.60	1.50
Profitability Ratios						
EBITDA margin	66.1%	66.3%	64.8%	70.2%	67.7%	65.6%
EBIT margin	34.1%	35.0%	30.3%	38.2%	33.2%	34.5%
Profit margin	17.3%	18.7%	13.2%	18.6%	14.9%	15.7%
Return on equity	13.5%	14.6%	10.0%	16.7%	13.0%	13.7%
Return on capital	5.4%	5.7%	4.7%	6.7%	5.7%	6.0%

1 Including operating leases.

Operating Statistics

	For the year ended March 31				
Electricity Sold - Breakdown (GWh)	**2018**	**2017**	**2016**	**2015**	**2014**
Residential	18,150	18,068	17,331	17,047	17,965
Light industrial & commercial	18,874	18,968	18,421	18,564	18,501
Large industrial	13,440	13,177	13,669	14,020	13,994
Other	6,709	7,439	7,879	1,582	2,558
Total domestic electricity sold	**57,173**	**57,652**	**57,300**	**51,213**	**53,018**
Trading volumes	15,046	16,740	14,732	21,928	23,806
Total sold	**72,219**	**74,392**	**72,032**	**73,141**	**76,824**
Domestic energy sales growth	(1%)	1%	11%	(3%)	(8%)
Generation Capacity (MW)					
Hydro	11,918	11,870	11,869	11,379	10,927
Gas (Burrard Generating Station)	180	183	175	1,120	1,120
Installed capacity	**12,098**	**12,053**	**12,044**	**12,499**	**12,047**
Energy Generated (GWh)					
Hydro	47,926	48,736	49,352	41,230	45,328
Gas	0	0	24	26	84
Other thermal	91	74	191	187	184
Gross power generated	**48,017**	**48,810**	**49,567**	**41,443**	**45,596**
Plus: purchases & exchange net	29,656	30,509	28,178	36,184	35,961
Energy generated & purchased	**77,673**	**79,319**	**77,745**	**77,627**	**81,557**
Less: transmission losses & internal use	(5,454)	(4,927)	(5,713)	(4,486)	(4,733)
Total sold	**72,219**	**74,392**	**72,032**	**73,141**	**76,824**
Energy lost & used/energy gen. & purch.	-7.0%	-6.2%	-7.3%	-5.8%	-5.8%
Maximum primary peak demand (MW)	9,651	10,194	9,602	9,441	10,072
Peak demand/Installed capacity	79.8%	84.6%	79.7%	75.5%	83.6%

Rating History

	Current	2018	2017	2016	2015	2014
Long-Term Obligations (bsd on Prov of BC)*	AA (high)	AA (high)	AA (high)	AA (high)	AA (high)	AA (high)
Short-Term Obligations (bsd on Prov of BC)*	R-1 (high)	R-1 (high)	R-1 (high)	R-1 (high)	R-1 (high)	R-1 (high)

* These obligations are based on the status of BC Hydro as a Crown agent of the Province and reflect the Province's debt ratings. The rating assigned to the Long-Term Obligations is also applicable to $10 million of debt issued by BC Hydro and guaranteed by the Province.

Related Research

- "DBRS Confirms British Columbia at AA (high) with a Stable Trend," April 2, 2018.
- British Columbia, Province of: Rating Report, April 2, 2018.

Commercial Paper Limit

- $4.5 billion.

Previous Report

- British Columbia Hydro and Power Authority: Rating Report, January 5, 2018.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrs.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

The DBRS group of companies consists of DBRS, Inc. (Delaware, U.S.)(NRSRO, DRO affiliate); DBRS Limited (Ontario, Canada)(DRO, NRSRO affiliate); DBRS Ratings GmbH (Frankfurt, Germany)(CRA, NRSRO affiliate, DRO affiliate); and DBRS Ratings Limited (England and Wales)(CRA, NRSRO affiliate, DRO affiliate). For more information on regulatory registrations, recognitions and approvals, please see: http://www.dbrs.com/research/highlights.pdf.

Rating Report

Hydro-Québec

DBRS

Insight beyond the rating.

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Ratings

Debt	Rating	Rating Action	Trend
Guaranteed Long-Term Debt*	A (high)	Confirmed	Stable
Commercial Paper*	R-1 (middle)	Confirmed	Stable

* Guaranteed by the Province of Québec.

Rating Update

On June 15, 2018, DBRS Limited (DBRS) confirmed the Guaranteed Long-Term Debt rating of Hydro-Québec (the Company) at A (high) and the Commercial Paper (CP) rating at R-1 (middle), both with Stable trends. The ratings assigned to the Company are a flow-through of the ratings of the Province of Québec (the Province; rated A (high) and R-1 (middle) with Stable trends by DBRS). The Province unconditionally guarantees most of the Company's outstanding debt, which consists essentially of bonds and medium-term notes (approximately 96% of total debt as at December 31, 2017). The remaining 4% of debt not guaranteed consists of non-market debt. Please see the *DBRS Criteria: Guarantees and Other Forms of Support* methodology for further detail.

Hydro-Québec's business risk profile continues to benefit from its integrated operations, especially its significant generating capacity (37.3 gigawatts (GW) as at December 31, 2017), of which 99% is from relatively low-cost hydroelectric generation and provides the Company with a strong market position in the northeast region. In 2018, Hydro-Québec's Distribution segment transitioned into the first year of a four-year performance-based regulation (PBR) regime. Under PBR, the Distribution segment's 2018–2019 revenue requirement was determined under cost-of-service (COS), while revenue requirement for the subsequent three years will increase by inflation and growth factors less productivity and stretch factors (see the Regulation section for more details). DBRS notes that under PBR, the Distribution segment must achieve productivity for the cost elements subject to indexation (i.e. excluding electricity purchases and transmission costs) at least equal to the regulatory productivity and stretch factors in order to achieve the allowed return on equity (ROE; 8.20% for 2018–2019). However, DBRS views earnings pressure to be manageable as the 2019–2020 productivity and stretch factors are reasonable at 0.30% and 0.00%, respectively. Additionally, DBRS notes that the Transmission segment is expected to transition to the PBR framework as well beginning in 2019 for a four-year period.

Hydro-Québec is currently in the midst of significant capital expenditures (capex; $3.8 billion in 2017 and $3.6 billion planned

Continued on P.2

Financial Information

	12 mos. to March 31	For the year ended December 31 1				
(CAD millions where applicable)	2018	2017	2016	2015	2014	2013
Total debt	47,827	45,267	45,916	45,992	44,775	44,500
Total debt in capital structure 2	66.6%	67.0%	68.0%	68.7%	69.0%	69.1%
Cash flow/Total debt	12.1%	12.9%	11.9%	13.8%	13.0%	11.6%
EBIT gross interest coverage (times)	2.15	2.12	2.15	2.19	2.22	2.08
Net results before non-recurring items	2,947	2,846	2,861	3,147	3,325	2,938
Cash flow from operations	5,772	5,817	5,483	6,333	5,805	5,148
Electricity sales (GWh)	N/A	205,638	201,989	201,127	201,127	205,484

1 2014 to 2018 based on U.S. GAAP; 2013 based on Canadian GAAP. 2 Adjusted for accumulated other comprehensive income.

Issuer Description

Hydro-Québec, a Crown corporation of the Province of Québec, generates, transmits and distributes electricity primarily from renewable energy sources. The Company comprises four main segments: Hydro-Québec Production (Generation), Hydro-Québec TransÉnergie (Transmission), Hydro-Québec Distribution (Distribution) and Hydro-Québec Innovation, équipement et services partagés (Construction).

Rating Update (CONTINUED)

for 2018), with work continuing on the Romaine Complex generation project (Romaine-3 commissioned in September 2017 and Romaine-4 expected to be in service around 2020) and transmission line maintenance and upgrades. The Company also plans to grow by acquiring assets or stakes in companies internationally, with a focus on targets involved in transmission or hydroelectric generation. DBRS notes that if Hydro-Québec acquires assets or companies that (1) operate in a less favourable regulatory regime or (2) for merchant generation, operate in more challenging environments, this could negatively affect the Company's business risk profile. Additionally, if these investments are debt financed, this could have a negative impact on the financial profile. DBRS expects Hydro-Québec to be stringent in its investment decisions and only invest in assets or companies that are commensurate with its current risk profile and to remain prudent in its financing plans.

Rating Considerations

Strengths

1. Debt guaranteed by the Province

The ratings assigned to the Company are a flow-through of the ratings of the Province. Approximately 96% (as at December 31, 2017) of Hydro-Québec's outstanding debt is guaranteed by the Province.

2. Low-cost hydroelectricity-based generation

Hydro-Québec's cost structure is very competitive, largely as a result of the, on average, low cost of hydro power that accounts for 99% of total generating capacity and over 99% of energy generated (average cost per kilowatt hour (kWh) generated was 2.04 cents in 2017). DBRS notes, however, that the cost of production from new generating plants, such as the Romaine Complex, will likely increase the overall average cost of generation for the Company. However, Hydro-Québec will continue to purchase almost all of the power generated from Churchill Falls (Labrador) Corporation Limited (CF(L)Co) at rates equal to 0.20 cents/kWh until 2041. The Company also has a winter capacity contract with CF(L)Co that provides it with additional winter capacity at a maximum cost of $1.5 billion from 1998 to 2041. Hydro-Québec Production sells the majority of this electricity to Québec customers through the heritage pool.

3. Strong water reservoir capacity

Through its 28 large reservoirs, the Company benefits from significant water storage capacity (176.5 terawatt hours (TWh)). The storage capacity allows Hydro-Québec to buy low-cost power during off-peak periods and sell self-generated power at higher rates during peak-demand periods to optimize export revenues. In addition, the storage capacity greatly simplifies its own peak-shaving needs since the hydroelectric generation equipment is easily started up and shut down.

4. Export access to major markets

Hydro-Québec has access to Ontario, New Brunswick and the northeastern United States, providing the Company with export opportunities. These interconnections are, however, limited relative to the amount of installed capacity, which restricts export capacity over the longer term. Hydro-Québec exported approximately 17% of net electricity sales volume to these markets in 2017. In its 2016–2020 Strategic Plan, the Company plans to increase its export opportunities, including through participation in potential transmission projects outside the Province.

Challenges

1. High level of planned capex

Hydro-Québec is expected to spend a significant amount of capex in 2018 (approximately $3.6 billion), which could put some pressure on its financial profile. The Company projects capex to remain high, including $3.2 billion in 2019. Additionally, in its 2016–2020 Strategic Plan, Hydro-Québec stated that it plans to pursue assets or partnerships in potential transmission or hydroelectric generation projects outside the Province. These potential opportunities could lead to further increase in capex over the medium term. As capex has consistently been above historical depreciation, this has resulted in a general increase in the debt load for the Company; however, this has been mitigated by corresponding growth in the equity and overall asset base as well as the guarantee provided by the Province.

2. Hydrology risk

The Company's earnings and cash flows are sensitive to changes in water levels, given its reliance on hydroelectric-based generating capacity.

3. Regulatory risk

Hydro-Québec's strong asset profile is undermined by (a) relatively low regulated rates for transmission and distribution activities and (b) high dividend payouts. DBRS notes that, with the switch to a PBR framework for the Distribution and Transmission segments, the Company will face performance pressure and will have to achieve efficiencies, for the cost elements subject to indexation, at least equal to the regulatory productivity factor in order to earn the allowed ROE. DBRS finds that the productivity and stretch factors for the Distribution segment in 2019–2020 (0.30% and 0.00%, respectively) as reasonable and believes that earnings pressure will be manageable for Hydro-Québec. The terms and factors of the Transmission segment PBR will be set in its 2019 rate adjustment application.

Earnings and Outlook

	12 mos. to March 31	For the year ended December 31 [1]				
(CAD millions where applicable)	2018	2017	2016	2015	2014	2013
Total revenue	13,718	13,468	13,339	13,754	13,652	12,878
EBITDA	8,196	8,045	7,990	8,309	8,343	7,850
EBIT	5,501	5,359	5,393	5,596	5,750	5,367
Gross interest expense	2,560	2,532	2,510	2,552	2,594	2,584
Net results before non-recurring items	2,947	2,846	2,861	3,147	3,325	2,938
Non-recurring items	0	0	0	0	0	4
Reported net results	2,947	2,846	2,861	3,147	3,325	2,942
Return on equity	13.8%	14.4%	14.6%	16.8%	17.8%	15.3%
Segmented Repoted Net Results						
Distribution	399	333	342	364	343	410
Transmission	545	554	561	559	560	513
Generation	2,010	1,948	1,870	2,130	2,301	1,926
Other	(7)	11	88	94	121	89
Total	**2,947**	**2,846**	**2,861**	**3,147**	**3,325**	**2,938**

1 2014 to 2018 based on U.S. GAAP; 2013 based on Canadian GAAP.

2017 Summary

- Earnings in 2017 were largely on par with 2016, with stronger results from the Generation segment offset by decreases in the Distribution, Transmission and Other segments.
- Net results from the Generation segment increased because of (1) record exports of 34.4 TWh, compared with 32.6 TWh in 2016, and (2) higher revenues from domestic sales due to very cold temperatures in December 2017, and the indexing of heritage pool electricity.
  - This was partly offset by higher electricity and fuel purchases, depreciation and amortization, and taxes.
- Net results from the Transmission and Distribution segments fell because of $27 million and $18 million, respectively, payable to customers under an earnings-sharing mechanism that came into effect for the first time in 2017.
  - For the Distribution segment, this was partly offset by (1) the above-mentioned lower temperatures, (2) higher baseload demand and (3) average rate increases of 0.7% effective April 1, 2016, and 0.7% effective April 1, 2017.

2018 Summary/Outlook

- Net results for the 12 months ending March 31, 2018 (LTM 2018) increased compared with 2017 because of stronger results from both the Distribution and the Generation segments.
  - Net results from the Generation segment increased due to the more normal temperatures in Q1 2018 compared with the warmer temperatures in Q1 2017. This led to higher volumes supplied to domestic customers during peak periods.
  - Net results from the Distribution segment increased because of the weather variance and the April 1, 2017, rate increase.
- As per its 2016–2020 Strategic Plan, Hydro-Québec is targeting net results of $2.5 billion for the 2018 fiscal year.
  - The Company has forecasted lower net results in 2018 because of expected lower export prices and lower domestic demand.
- In its 2016–2020 Strategic Plan, the Company also plans to limit average annual rate increases to lower or equal to inflation, largely through controlling operating expenses.
  - As well, under PBR, the Distribution segment's revenue requirement for 2019–2022 will increase by inflation and growth factors less productivity and stretch factors. The Distribution segment will have to achieve efficiencies in the cost elements subject to indexation (i.e. most distribution costs, excluding electricity purchases and transmission costs) equal to the productivity and stretch factors in order to meet its allowed ROE.
  - The Transmission segment is expected to transition to the PBR framework beginning in 2019 as well. For the first year, revenue requirement will be determined under COS. In the subsequent three years, the maintenance and operation costs will increase by inflation and growth factors less productivity and stretch factors, while capital and depreciation costs will continue to be determined under COS.

Financial Profile and Outlook

	12 mos. to March 31	For the year ended December 31 1				
(CAD millions where applicable)	2018	2017	2016	2015	2014	2013
Net results before non-recurring items	2,947	2,846	2,861	3,147	3,325	2,938
Depreciation & amortization	2,695	2,686	2,597	2,713	2,593	2,483
Accrued benefits and other	130	285	25	473	(113)	(273)
Cash flow from operations	**5,772**	**5,817**	**5,483**	**6,333**	**5,805**	**5,148**
Dividends paid	(2,135)	(2,146)	(2,360)	(2,535)	(2,207)	(645)
Capital expenditures	(3,799)	(3,754)	(3,460)	(3,440)	(3,815)	(4,335)
Free cash flow (bef. working cap. changes)	**(162)**	**(83)**	**(337)**	**358**	**(217)**	**168**
Changes in non-cash work. cap. items	(63)	(239)	21	(98)	68	(131)
Net free cash flow	**(225)**	**(322)**	**(316)**	**260**	**(149)**	**37**
Acquisitions & long-term investments	0	0	0	0	0	0
Short-term investments	251	492	(272)	(218)	43	(1,067)
Proceeds on asset sales	0	0	0	0	0	0
Net equity change	0	0	0	0	0	0
Net debt change	(160)	(218)	78	(1,050)	(1,202)	94
Other	(446)	(658)	(895)	2,385	1,146	448
Change in cash	**(580)**	**(706)**	**(1,405)**	**1,377**	**(162)**	**(488)**
Total debt	47,827	45,267	45,916	45,992	44,775	44,500
Cash and equivalents	1,963	1,649	3,427	4,543	2,935	3,384
Total debt in capital structure 2	66.6%	67.0%	68.0%	68.7%	69.0%	69.1%
Cash flow/Total debt	12.1%	12.9%	11.9%	13.8%	13.0%	11.6%
EBIT gross interest coverage (times)	2.15	2.12	2.15	2.19	2.22	2.08
Dividend payout ratio	72.4%	75.4%	82.5%	80.6%	66.4%	22.0%

1 2014 to 2018 based on U.S. GAAP; 2013 based on Canadian GAAP. 2 Adjusted for accumulated other comprehensive income.

2017 Summary

- Cash flow from operations increased compared with 2016 results.
- Capex increased in 2017 as the Company continued work on the Romaine Complex and improving the reliability of its transmission assets.
  - Hydro-Québec spent $1.5 billion on development projects in 2017, including approximately $561 million toward development activities, mainly for the continued construction of the Romaine hydroelectric complex. Sustainment capex totalled $2.3 billion.
- In accordance with the *Hydro-Québec Act,* dividends paid for the year were 75% of the preceding year's reported net results. The Company declared dividends of $2.1 billion in 2017.
- Hydro-Québec generated a net free cash flow deficit in 2017, which was funded through cash on hand.
- The Company had net cash payments of $632 million for credit risk management, largely because of changes in the exchange rate between the Canadian and U.S. dollar.

2018 Summary/Outlook

- Cash flow from operations for LTM 2018 was largely in line with 2017.
- The Company has planned capex of $3.6 billion for 2018 ($697 million spent in Q1 2018), with $2.2 billion for asset sustainment and optimization projects. Hydro-Québec plans to invest $1.0 billion in its Generation segment and $1.8 billion in its Transmission segment.
- Combined with dividends of $2.1 billion paid in 2018, DBRS anticipates the Company to be free cash flow neutral for the year. DBRS anticipates that any deficits that may arise to be funded through debt issuances.
- As a result of the current low interest rate environment and continued growth in the equity base, Hydro-Québec's key financial metrics should remain stable in 2018.

Liquidity and Bank Lines

- Hydro-Québec has a reasonable liquidity profile. The Company's credit facilities, which are guaranteed by the Province, consist of the following:
  - USD 2.0 billion guaranteed committed bank facility maturing in 2023 (undrawn as at December 31, 2017).
  - USD 3.5 billion (or Canadian-dollar equivalent) guaranteed CP program ($8.1 million outstanding as at December 31, 2017).
- Hydro-Québec has $1.0 billion of operating credit lines available in Canadian or U.S. dollars, not guaranteed by the Province ($1.5 million drawn as at December 31, 2017).

Long-Term Debt Maturities

(As at December 31, 2017)	2018	2019	2020	2021	2022+	Total [1]
(CAD millions)	1,176	3,143	3,013	2,301	31,426	**41,059**
% of total	2.9%	7.7%	7.3%	5.6%	76.5%	**100.0%**

* As at December 31, 2017, the Province of Québec guaranteed $42,942 million of Hydro-Québec's outstanding debt after taking into account short-term borrowings and sinking funds.
1 Long-term debt maturities are presented at par value until 2055. In Hydro-Québec's consolidated financial statements, the long-term debt is shown at the amortized cost and totalled $45.0 billion. It includes adjustment for fair-value hedged risk, private investments of debt and the obligations maturing in 2060.

- The debt maturity profile is well spread out, with only 10.6% of total debt maturing prior to year-end 2019.
- The Company has solid access to the debt markets and raised approximately $1.2 billion in the Canadian market in 2017.

Description of Operations

Hydro-Québec, a Crown corporation of the Province of Québec, is segmented into four reportable business segments: (1) Hydro-Québec Production (Generation); (2) Hydro-Québec TransÉnergie (Transmission); (3) Hydro-Québec Distribution (Distribution); and (4) Hydro-Québec Innovation, équipement et services partagés (Construction). Other business segments and activities are grouped under Corporate and Other Activities for reporting purposes.

Hydro-Québec Production

- This segment generates power for the Québec market and sells electricity in wholesale markets.
- Generating fleet includes 63 hydroelectric generating stations and one thermal generating station.
- The Company has 28 large reservoirs with a storage capacity of 176.5 TWh.
- Total installed capacity of 37.3 GW. This segment is obligated to supply a heritage pool of up to 165 TWh per year at an authorized average price of 2.90 cents/kWh for 2017.
- Major projects include the Romaine hydroelectric complex. Romaine-2 (640 megawatts (MW)) and Romaine-1 (270 MW) were commissioned in 2014 and 2015, respectively. Romaine-3 (395 MW) was commissioned in September 2017, with Romaine-4 (245 MW) expected to be commissioned around 2020.
- The Production segment's primary business objectives are the security of Québec's electricity supply and the profitability of its operations.

Hydro-Québec TransÉnergie

- This segment operates one of the most extensive transmission systems in North America.
- The transmission lines run into the northeastern United States and have interconnections available to customers both inside and outside Québec. The segment operates over 34,000 kilometres (km) of lines and 522 substations.
- In Québec, transmission is currently regulated by the Régie de l'énergie (Régie) on the basis of COS.
- Hydro-Québec TransÉnergie will continue to develop its transmission system in 2018 to meet growing demand for capacity.

Hydro-Québec Distribution

- This segment provides a reliable delivery system for electricity to customers in Québec.
- The segment operates over 117,000 km of medium voltage lines and over 100,000 km of low voltage lines through its distribution system, one hydroelectric generating station, 23 thermal generating stations, 11 substations and 272 km of transmission lines supplying customers on off-grid systems.
- While historically Distribution had been regulated by the Régie on the basis of COS, it transitioned to a PBR regime in 2018.
- The segment relies on the heritage pool of 165 TWh provided by Hydro-Québec Production. Demand beyond the volume from the heritage pool is purchased from the market.

Description of Operations (CONTINUED)

- The Distribution segment has 75 contracts (includes 15 under development) with independent producers for 5,789 MW (includes 1,022 MW under development) of energy for deliveries.
- The majority of the contracts are with wind developers, consisting of 3,710 MW (includes 414 MW under development).

Hydro-Québec Innovation, équipement et services partagés

- This segment, which includes the Société d'énergie de la Baie James, constructs the generation and transmission projects on behalf of Hydro-Québec.

Regulation

In Québec, power generation is not regulated, while transmission is regulated by the Régie under a COS regime and distribution under a PBR regime. DBRS does not expect the switch to a PBR framework from a COS framework will have a material impact on the Company's business or financial risk profiles as long as Hydro-Québec is allowed to continue recovering prudently spent costs and earn a reasonable return on its investments.

Generation

- A heritage pool exists whereby Hydro-Québec Production is required to supply Hydro-Québec Distribution with a maximum of 165 TWh per year for the native load at an authorized average price subject to a yearly indexation. The price was 2.90 cents/kWh for 2017.
- The wholesale market is open to competition for all needs in excess of the heritage pool.
- Hydro-Québec retains sole responsibility for developing hydroelectricity generation sites with a capacity of over 50 MW.
- Given the low cost of power offered by Hydro-Québec Production, none of the ten municipal distributors have utilized the wholesale market for electricity needs.

Transmission

- The cost of transmission is passed on to Hydro-Québec Distribution and other customers.
- Hydro-Québec TransÉnergie filed its 2017 rate application with the Régie in July 2016. The Régie approved the following as per the March 1, 2017, April 28, 2017, and May 1, 2017, decisions:
  - ROE of 8.20% for 2017.
  - Maintaining the deemed capital structure of 70% debt to 30% equity.
  - Revenue requirement of $3,248.2 million for 2017.
  - Rate base of $19,862.4 million for 2017.
- Hydro-Québec TransÉnergie filed its 2018 rate application with the Régie in August 2017. The Régie approved the following as per the March 6, 2018, and March 28, 2018, decisions:
  - ROE of 8.20% for 2018.
  - Maintaining the deemed capital structure of 70% debt to 30% equity.
  - Revenue requirement of $3,340.5 million for 2018.
  - Rate base of $20,646.8 million for 2018.

Distribution

- The Régie approved the following for Hydro-Québec Distribution effective April 1, 2017, as per the March 1, 2017, and March 22, 2017, decisions:
  - ROE of 8.20% for 2017.
  - A deemed capital structure of 65% debt to 35% equity.
  - Revenue requirement of $11,693.0 million and additional revenue requirement of $71.4 million.
  - Rate base set at $10,747.7 million.
- These decisions led to an average rate increase of 0.7% for most customers (0.2% for Rate L) beginning April 1, 2017.
- The Régie approved the following for Hydro-Québec Distribution effective April 1, 2018, as per the March 7, 2018, and March 23, 2018, decisions:
  - ROE of 8.20% for 2018.
  - A deemed capital structure of 65% debt to 35% equity.
  - Revenue requirement of $11,820.4 million and additional revenue requirement of $30.2 million.
  - Rate base set at $10,710.1 million.
- These decisions led to an average rate increase of 0.3% for most customers (0% for Rate L) beginning April 1, 2018.
- In April 2017, the Régie issued its decision on Phase 1 of the implementation of a PBR framework for Hydro-Québec Distribution. A final decision regarding certain characteristics of the PBR was rendered on June 12, 2018 (following an interlocutory decision on May 16, 2018). In its decisions, the Régie approved the following characteristics for the PBR:
  - A term of four years, whereby the first year will be based on COS.

Regulation (CONTINUED)

- A revenue cap mechanism whereby total revenues will increase annually by an inflation factor and a growth factor, less a productivity and stretch factors.
- The inflation factor will be determined by the actual Consumer Product Index (CPI) for the Province and the average growth rate of wages in the Province.
- The growth factor will equal 75% of the increase in the number of Distribution customer accounts.
- The productivity factor, for the first PBR term, will be determined by the Régie for the first three years. The Distribution segment will submit a productivity study in year three of the PBR (2020). If the results are significantly different from the value of the productivity factor used for years two and three of the first PBR term, the Régie will assess if it is pertinent to adjust the productivity factor accordingly. In any event, the Régie may use the results to fix the productivity factor for the next PBR term.
- A Y factor for recurring expenses, over a threshold of $15 million, outside Hydro-Québec Distribution's control that will be flowed-through to customers (changes in the cost of capital, electricity purchases, transmission costs, costs related to energy conservation projects, pension cost, etc.).
- A Z factor for unexpected expenses, over a threshold of $15 million, outside Hydro-Québec Distribution's control that will be flowed-through to customers (costs related to a natural disaster, unforeseeable events in autonomous networks, major blackouts, changes in accounting standards, changes in the useful life of assets, etc.).
- An off-ramp, with details to be determined during a subsequent phase, should the actual return for the Distribution segment be higher or lower than a certain threshold over/below the allowed return.

• Additionally, the Régie had approved an earnings-sharing mechanism whereby under-earnings will be borne by the Company, while over-earnings will be shared (1) 50-50 for the first 100 basis points (bps) and (2) 75% to customers and 25% to Hydro-Québec for any additional earnings over the first 100 bps. The earnings-sharing mechanism came into effect in 2017 and would apply for the PBR term

• Final phase of the PBR implementation will be conducted during the 2019–2020 rate adjustment application, with the off-ramp clause and selection of service quality indicators to be linked to the earnings-sharing mechanism, to ensure efficiencies are not realized at the expense of service quality, to be determined.

  - Rates effective for 2019 will escalate based on the revenue cap mechanism.
  - In May 2018, the Régie approved for a productivity factor of 0.30% and stretch factor of 0.00%.

Assessment of Hydro-Québec's Regulatory Environment

The chart below reflects DBRS's assessment of the regulatory environment for Hydro-Québec based on DBRS's methodology guidelines.

Criteria	Score	Analysis
1. Deemed Equity	Excellent Good Satisfactory **Below Average** Poor	The deemed equity, as set by the Régie, is 35% for Hydro-Québec Distribution and 30% for Hydro-Québec TransÉnergie.
2. Allowed ROE	Excellent Good **Satisfactory** Below Average Poor	The allowed ROE for 2018 is 8.20%.
3. Energy Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	99% of Hydro-Québec's generation capacity originates from hydroelectricity, which is a lower cost than most alternatives. Furthermore, although generation is not regulated, a 165 TWh heritage pool supplies the native load at a low, annually indexed price, virtually eliminating the need for variable fuel cost adjustment.
4. Capital and Operating Cost Recoveries	Excellent Good **Satisfactory** Below Average Poor	There is a delay in capex recovery as it requires regulatory review and approval from the Régie. Operating cost recovery has not been a concern as the Régie uses forward test years. DBRS views the components to be used for the inflation factor under PBR (CPI and growth of wages in the Province) as reasonable.
5. COS versus Incentive Rate Mechanism	Excellent **Good** Satisfactory Below Average Poor	The Régie currently regulates transmission rates for Hydro-Québec on a COS basis. The Distribution segment transitioned to a four-year PBR beginning in 2018. Hearings for the implementation of a PBR regime for the Transmission segment began April 2017 and is expected to be in effect for 2019.
6. Political Interference	Excellent Good Satisfactory **Below Average** Poor	The Province plays a significant role in the market. Hydro-Québec is owned by the Province, and the distribution and transmission sectors are regulated by the Régie, a quasi-judicial body. There has been no adverse legislation in the regulated utility sector.
7. Stranded Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	There have been minimal stranded costs in Québec. The Company is able to recover substantially all costs through the rate-setting process.
8. Rate Freeze	**Excellent** Good Satisfactory Below Average Poor	There have been no province-wide rate freezes in Québec in the past six years.

Province of Québec

(Excerpt from "Québec, Province of: Rating Report" dated June 22, 2018. Please see report for more detail.)

On June 15, 2018, DBRS Limited confirmed the Issuer Rating and Long-Term Debt rating of the Province of Québec (Québec or the Province) at A (high) and its Short-Term Debt rating at R-1 (middle). All trends are Stable. The Province's track record of strong fiscal management is allowing the government to take advantage of economic momentum to provide additional tax relief, increase spending in priority areas and maintain its focus on debt reduction. While rising trade protectionism and an upcoming provincial election present near-term uncertainties for Québec's economic and fiscal outlook, sustained fiscal discipline and continued improvement in debt metrics will be positive for the credit profile.

Hydro-Québec

(CAD millions)	March 31	December 31			March 31	December 31	
Assets	**2018**	**2017**	**2016**	**Liabilities & Equity**	**2018**	**2017**	**2016**
Cash & equivalents	1,963	1,649	3,427	S.T. borrowings	1,677	8	7
Accounts receivable	3,187	2,486	2,049	Accounts payable	2,235	2,508	2,199
Prepaid expenses & other	479	421	442	Current portion L.T.D.	1,201	1,183	1,398
				Other current liab.	567	3,282	3,278
Total current assets	**5,629**	**4,556**	**5,918**	**Total current liab.**	**5,680**	**6,981**	**6,882**
Net fixed assets	64,098	63,990	62,691	Long-term debt	44,949	44,076	44,511
Goodwill & intangibles	867	871	938	Other L.T. liab.	4,709	4,918	4,070
Investments & others	6,333	6,313	5,620	Shareholders' equity	21,589	19,755	19,704
Total assets	**76,927**	**75,730**	**75,167**	**Total liab. & SE**	**76,927**	**75,730**	**75,167**

	12 mos. to March 31	For the year ended December 31 1				
Balance Sheet & Liquidity & Capital Ratios	**2018**	**2017**	**2016**	**2015**	**2014**	**2013**
Current ratio	0.99	0.65	0.86	0.92	0.82	0.92
Total debt in capital structure 2	66.6%	67.0%	68.0%	68.7%	69.0%	69.1%
Cash flow/Total debt	12.1%	12.9%	11.9%	13.8%	13.0%	11.6%
(Cash flow-dividends)/Capex (times)	0.96	0.98	0.90	1.10	0.94	1.04
Dividend payout ratio	72.4%	75.4%	82.5%	80.6%	66.4%	22.0%
Coverage Ratios (times)						
EBIT gross interest coverage	2.15	2.12	2.15	2.19	2.22	2.08
EBITDA gross interest coverage	3.20	3.18	3.18	3.26	3.22	3.04
Fixed-charges coverage	2.15	2.12	2.15	2.19	2.22	2.08
Profitability Ratios						
EBITDA margin	70.4%	70.2%	69.6%	70.3%	71.4%	69.4%
EBIT margin	47.2%	46.8%	47.0%	47.4%	49.2%	47.5%
Profit margin	25.3%	24.8%	24.9%	26.6%	28.5%	26.0%
Return on equity	13.8%	14.4%	14.6%	16.8%	17.8%	15.3%
Return on capital	7.4%	7.7%	7.7%	8.3%	8.7%	8.2%
Earnings Quality/Operating Efficiency						
Operating margin	47.2%	46.8%	47.0%	47.4%	49.2%	47.5%
Profit returned to government	72.4%	75.4%	82.5%	80.6%	66.4%	22.0%
Customers/employees	N/A	216	217	213	209	205
Growth in customer base	N/A	0.82%	0.71%	0.83%	0.91%	0.84%
GWh sold/employee	N/A	10.4	10.3	10.2	10.0	10.2

1 2014 to 2018 based on U.S. GAAP; 2013 based on Canadian GAAP. 2 Adjusted for accumulated other comprehensive income.

	For the year ended December 31				
Electricity Sold (GWh) 1	**2017**	**2016**	**2015**	**2014**	**2013**
Residential	66,111	65,065	66,558	68,074	65,983
Commercial, Institutional and Small Industrial	45,816	45,483	45,335	45,189	44,620
Large Industrial	53,699	53,635	54,200	55,738	56,855
Other	5,077	5,062	5,170	5,222	5,818
Total domestic	**170,703**	**169,245**	**171,263**	**174,223**	**173,276**
Exports	34,935	32,744	29,864	26,624	32,208
Total sold	**205,638**	**201,989**	**201,127**	**200,847**	**205,484**
Domestic sales growth	0.9%	-1.2%	-1.7%	0.5%	2.9%
Total exports growth	6.7%	9.6%	12.2%	-17.3%	14.7%
Total sales growth	1.8%	0.4%	0.1%	-2.3%	4.6%
Generation Capacity (MW)					
Hydroelectricity	36,767	36,366	36,370	36,100	35,364
Oil + diesel	542	542	542	543	704
Installed, in-service capacity	**37,309**	**36,908**	**36,912**	**36,643**	**36,068**
Available from Churchill Falls	5,428	5,428	5,428	5,428	5,428
Available from wind farms	3,508	3,508	3,260	2,857	2,399
Other sources of supply	1,367	1,378	1,385	1,386	1,399
Total available supply	**47,612**	**47,222**	**46,985**	**46,314**	**45,294**
Energy Generated (GWh)					
Hydroelectricity	177,068	172,267	170,899	172,971	178,152
Nuclear/Oil/Wind	7	3	5	7	5
Gross energy generated 2	**177,075**	**172,270**	**170,905**	**172,978**	**178,157**
Plus: Churchill Falls purchases	26,218	29,010	28,692	27,567	29,787
Plus: other energy purchases	17,345	16,029	16,941	16,580	14,289
Energy generated + purchased	**220,638**	**217,309**	**216,538**	**217,126**	**222,232**
Less: transmission losses + internal use	15,000	15,320	15,411	15,582	16,748
Total sold	**205,638**	**201,989**	**201,127**	**201,544**	**205,484**
Energy lost + used/energy gen. + purch.	6.8%	7.0%	7.1%	7.2%	7.5%
Primary peak demand (MW)*	38,204	36,797	37,349	38,743	39,031
Peak demand/installed capacity	102.4%	99.7%	101.2%	105.7%	108.2%
Peak demand/installed capacity 3	89.4%	86.9%	88.2%	92.1%	94.1%
Export Interconnections (MW)					
Ontario	2,705	2,705	2,705	2,705	2,735
New Brunswick	1,029	1,029	1,029	1,029	1,029
New England	2,275	2,275	2,275	2,275	2,275
New York	1,999	1,999	1,999	1,999	1,999
Total	**8,008**	**8,008**	**8,008**	**8,008**	**8,038**
Interconnections as a % of installed capacity	21.5%	21.7%	21.7%	21.9%	22.3%

* Power requirements at the annual peak of demand in Québec for the winter.
1 Data relating to continuing operations. 2 Does not include off-grid systems. 3 Includes Churchill Falls capacity.

Rating History

	Current	2017	2016	2015	2014	2013
Guaranteed Long-Term Debt *	A (high)	A (high)	A (high)	A (high)	A (high)	A (high)
Commercial Paper *	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)

* Guaranteed by the Province of Québec.

Previous Action

- Confirmed, June 15, 2018.

Related Research

- *Québec, Province of: Rating Report*, June 22, 2018.
- "DBRS Confirms Province of Québec at A (high) and R-1 (middle), Stable Trends," June 15, 2018.

Commercial Paper Limit

- USD 3.5 billion or equivalent CAD.

Previous Report

- Hydro-Québec: Rating Report, June 30, 2017.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrs.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

The DBRS group of companies consists of DBRS, Inc. (Delaware, U.S.)(NRSRO, DRO affiliate); DBRS Limited (Ontario, Canada)(DRO, NRSRO affiliate); DBRS Ratings Limited (England and Wales)(CRA, NRSRO affiliate, DRO affiliate); and DBRS Ratings México, Institución Calificadora de Valores S.A. de C.V. (Mexico)(CRA, NRSRO affiliate, DRO affiliate). Please note that DBRS Ratings Limited was registered as an NRSRO affiliate on July 14, 2017. For more information on regulatory registrations, recognitions and approvals, please see: http://www.dbrs.com/research/225752/highlights.pdf.

Rating Report

Ontario Power Generation Inc.

DBRS
Insight beyond the rating.

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable
Unsecured Debt	A (low)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

On April 5, 2019, DBRS Limited (DBRS) confirmed the Issuer Rating and the Unsecured Debt rating of Ontario Power Generation Inc. (OPG or the Company) at A (low) and the rating of the Company's Commercial Paper (CP) at R-1 (low). All trends are Stable. The ratings of OPG continue to be supported by (1) the reasonable regulatory regime in place for the Company's regulated generation facilities, (2) strong cash flow-to-debt and debt-to-capital ratios and (3) continuing financial support from its shareholder, the Province of Ontario (the Province; rated AA (low) with a Stable trend by DBRS). The Province, through its agent, the Ontario Electricity Financial Corporation (OEFC; rated AA (low) with a Stable trend by DBRS), provides most of OPG's financing (approximately 43% of consolidated debt). The Company's remaining debt includes project financing (31%), non-recourse debt issued by Fair Hydro Trust (Senior Notes rated AAA (sf), Under Review with Negative Implications by DBRS; 11%), CP (2%) and Senior Notes issued under the Medium Term Note Program (12%).

In March 2019, the Province introduced Bill 87, *Fixing the Hydro Mess Act, 2019*, which includes winding down the Fair Hydro Plan. OPG will remain the Financial Services Manager for the outstanding Fair Hydro Trust debt, which will become obligations of the Province. DBRS does not expect this development to have a material impact on the Company as (1) the Fair Hydro Trust debt will continue to be bankruptcy remote and ring-fenced from OPG (all debt is non-recourse to the Company) and (2) the credit rating on the Company's investment in the Subordinated Notes (rated AA (sf), Under Review with Negative Implications by DBRS) will likely remain investment grade while the Junior Subordinated Notes (rated A (sf), Under Review with Developing Implications by DBRS) will not necessarily be negatively affected by this change (see the DBRS press release dated March 26, 2019, titled "DBRS Maintains Fair Hydro Trust, Series 2018-1 and Series 2018-2 Notes Under Review" for more details).

OPG's key credit metrics improved in 2018, following the approval of its 2017–2021 rates application by the Ontario Energy Board (OEB) in December 2017. The Company's profitability strengthened significantly, with corporate return on equity (ROE) of 7.8% (adjusted for a $205 million gain on sale of property; 5.1% in 2017) closer to the regulatory allowed ROE of 8.78%. However, DBRS continues to view a positive rating action as unlikely in the short term because of the ongoing capex program, including the $12.8 billion Darlington Refurbishment project (the Darlington Refurbishment). A downgrade could occur should there be significant cost overruns with the Darlington Refurbishment that then result in stranded costs. DBRS notes that the Darlington Refurbishment is currently on budget and on schedule.

Financial Information

	For the year ended December 31				
	2018	**2017**	**2016**	**2015**	**2014**
Cash flow/Total debt 1, 2	45.0%	40.0%	40.6%	31.9%	28.7%
Total debt in capital structure 1, 2, 3	26.9%	26.2%	34.3%	35.8%	37.3%
EBIT gross interest coverage (times) 1, 2, 4	1.00	(0.24)	(0.14)	(0.86)	0.27
(Cash flow - n.w.f.)/Total debt 1, 2, 5	39.3%	33.7%	32.9%	25.4%	22.5%

1 Including operating leases. 2 Excludes non-recourse debt. 3 Adjusted for Accumulated Other Comprehensive Income. 4 Excluding earnings from nuclear fixed asset removal and nuclear waste management funds. 5 Includes nuclear waste funding (n.w.f.) payments as they are not discretionary.

Issuer Description

Ontario Power Generation is an electricity-generating company with a diverse portfolio of over 16,000 megawatts of in-service generating capacity. The Company is wholly owned by the Province of Ontario.

Rating Considerations

Strengths

1. Support of shareholder (the Province)
The Province indirectly provides OPG with a large portion of its long-term funding requirements through the OEFC, a government-financing arm for provincial power companies. However, this debt is not directly guaranteed by the Province. As at December 31, 2018, OPG had approximately $3.4 billion of notes payable to the OEFC, comprising 43% of the Company's outstanding debt. DBRS believes that the Province will continue to support its investment since OPG is a creation of the Province and is integral to fulfilling Ontario's energy needs. DBRS additionally believes that the Province will, in exceptional circumstances, provide support to OPG.

2. Dominant market position in Ontario
OPG's importance in Ontario is demonstrated by the fact that it is the primary electricity generator in the Province, accounting for approximately 50% of electricity produced in Ontario in 2018.

3. Reasonable regulatory framework
The reasonable regulatory framework has allowed the Company to recover prudently incurred costs; however, DBRS notes that the unsuccessful appeal of the OEB's decision to disallow labour compensation costs related to OPG's nuclear operations has increased uncertainty regarding the Company's ability to fully recover its nuclear cost through future regulated prices (refer to the Regulation section for details). DBRS also notes that, under an incentive rate (IR) framework, OPG's profitability could come under further pressure because of the need to meet efficiency and productivity benchmarks.

4. Limited nuclear waste management liabilities
As a result of the Ontario Nuclear Funds Agreement with the Province, OPG's exposure relating to nuclear waste management liabilities has been capped at $5.94 billion (in 1999 dollar terms) for the initial 2.23 million used fuel bundles produced. The Company is, however, responsible for the incremental costs related to the management of used fuel bundles in excess of 2.23 million bundles (currently 2.68 million). The used fuel obligation is funded by the used fuel fund, which is substantially fully funded. The Province provides a guarantee for any shortfall between the value of the nuclear fund and the Canadian Nuclear Safety Commission consolidated financial guarantee requirement.

Challenges

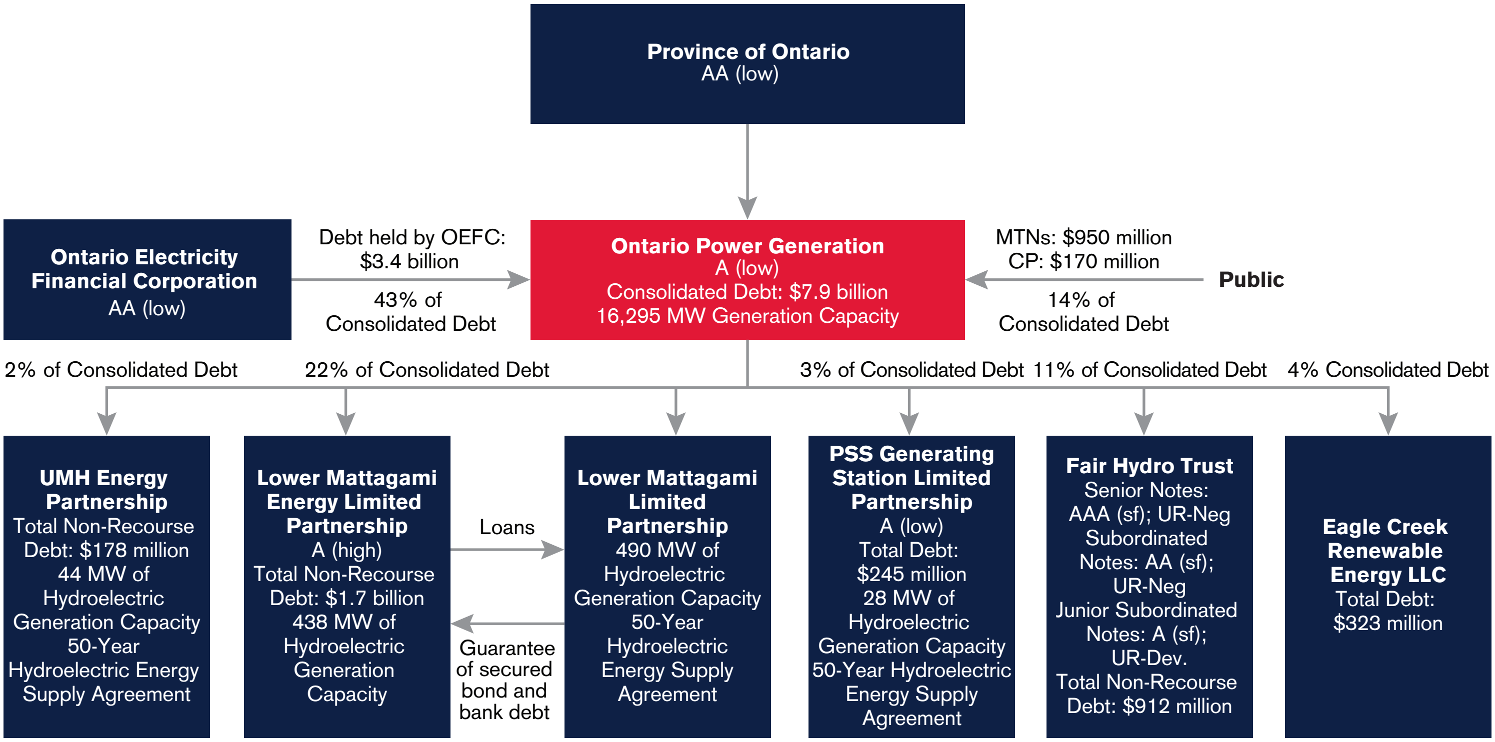
1. Significant capex program
OPG has a significant capex program underway (approximately $2.1 billion planned for 2019). The Company also faces significant execution risk as well as the potential for cost overruns associated with the Darlington Refurbishment because of the project's complexity and scale. DBRS expects that OPG will not undertake any major capex without having financing and a cost-recovery mechanism in place, thus minimizing financial risks.

2. Nuclear generation risks
Nuclear generation faces higher operating risks than other types of generation because of its complex technology (approximately 55% of OPG's production in 2018). Financial implications of forced outages, especially with older units (e.g., the Pickering Nuclear Generating Station (GS)), are greater given the high fixed-cost nature of these plants as well as the fact that lost revenues resulting from outages are not recoverable through rates.

3. High cost base
OPG's high cost base has resulted in several disallowances by the OEB. For the most recent 2017–2021 rates decision, the OEB disallowed recovery of $100 million in the operations, maintenance and administration (OM&A) budget annually. DBRS believes that OPG's inability to fully recover compensation costs in future regulated prices could have a negative impact on earnings and affect the Company's ability to achieve its approved ROE. DBRS notes that OPG has been combatting this issue through its cost-reduction and efficiency-improvement initiative, which has saved $1.0 billion through a reduction in headcount of over 2,800 since 2011.

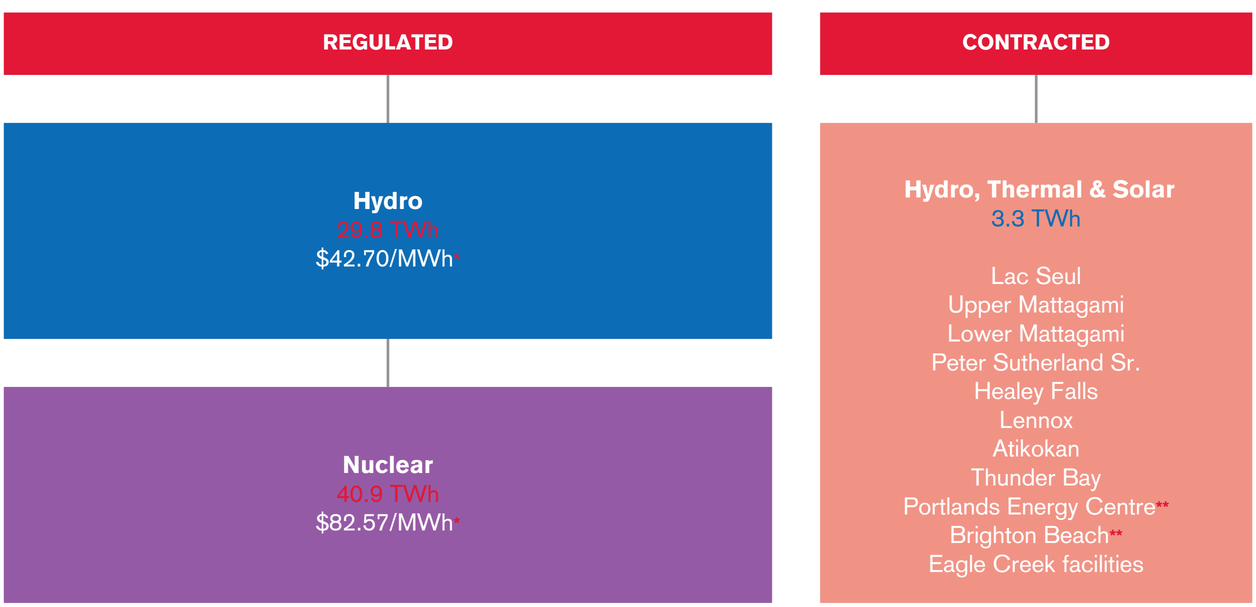
4. Political intervention
OPG is subject to political intervention, largely because of its ownership by the Province and changes in government mandates and policies. DBRS notes that though the Province has committed to having the Company run more autonomously, the risk of further government intervention still exists.

Simplified Organizational Chart



As of December 31, 2018.

OPG's Price Structure



* Rates as of December 31, 2018.
** 50% ownership interest.

For the year ended December 31, 2018.

OPG's Price Structure (CONTINUED)

- OPG sells electricity to consumers through the IESO.
- Regulated facilities sell at rates set by the OEB, which could include rate riders used for the recovery of nuclear deferral and hydroelectric variance account balances.
- The Contracted and Other Generation Portfolio includes (1) assets in Ontario that sell electricity at prices set through Energy Supply Agreements or other long-term contracts with the Independent Electricity System Operator (IESO); and (2) Eagle Creek Renewable Energy LLC (Eagle Creek), which holds interest in 76 hydroelectric GS and two solar facilities throughout the United States.
  - The Eagle Creek facilities either sell into the merchant market or operate under long-term energy or capacity supply contracts.

Major Projects

Project	Estimated Cost (CAD millions)	Spent as of Dec. 31, 2018 (CAD millions)	In-Service Target Date
Darlington Refurbishment	12,800	5,513	2026*
Ranney Falls Hydroelectric GS	77	57	2019
Nanticoke Solar Facility	107	89	2019**

* Four units with staged in-service. Last unit scheduled to be completed by 2026. ** Completed in March 2019.

- **Darlington Refurbishment:** The Darlington Refurbishment will extend the operating life of the Darlington Nuclear GS by approximately 30 years. The execution of the refurbishment for the first unit began in October 2016 and the last unit is scheduled to be completed by 2026. The project is currently on schedule and on budget.
- **Ranney Falls Hydroelectric GS:** The Ranney Falls Hydroelectric GS project will replace an existing generation unit at Ranney Falls with a ten megawatt (MW) single-unit powerhouse. Construction commenced in 2017 and is currently on schedule and on budget.
- **Nanticoke Solar Facility:** The Nanticoke Solar Facility is a 44 MW solar facility near the Nanticoke GS. Site preparation commenced in March 2018, with the project completed on schedule and on budget in March 2019.
- OPG additionally acquired Eagle Creek in November 2018 for USD 298 million. DBRS views the business risk profile of Eagle Creek to be weaker than OPG as it is not regulated and not all of its facilities operate under long-term contracts, resulting in higher volume and price risk. However, DBRS does not expect the acquisition to have a material impact on the Company's overall business and financial risk assessment as its 226 MW capacity represents only around 1% of OPG's total generating capacity.

Regulation

- OPG benefits from a reasonable regulated environment. As at December 31, 2018, approximately 75% of its installed in-service capacity is regulated.
- OPG, regulated by the OEB under the *Electricity Restructuring Act, 2004 (Ontario)*, is allowed to receive regulated prices for all electricity generated from its nuclear facilities (5,728 MW) as well as most of its hydroelectric power facilities (6,426 MW).
- In May 2016, OPG filed its application with the OEB for rates effective January 1, 2017. The OEB issued its decision in December 2017.
  - The OEB approved for rates to be effective June 1, 2017, rather than the applied-for effective date of January 1, 2017.
  - Capital structure will remain at 55% debt (the Company had requested a change to 51% debt) and an allowed ROE of 8.78%. The ROE will not be updated throughout the five-year term.
  - For hydroelectric facilities, the Price Cap IR methodology is used. Under Price Cap IR, rates for the hydroelectric facilities are subject to a formula price cap that allows for an annual increase in the payment amount based on inflation less productivity and a utility-specific stretch factor, which can be reset annually (productivity factor of 0%, stretch factor of 0.3%).
  - Under Price Cap IR, OPG could file an Incremental Capital Module application to potentially recover any material and

Regulation (CONTINUED)

necessary prudently spent incremental capex during the IR period of five years. Additionally, the Company could initiate a regulatory review of its application if actual ROE falls 300 basis points below the approved ROE.

- For nuclear facilities, OPG requested the use of a Custom IR methodology and a rate-smoothing deferral account. Under its Custom IR methodology, nuclear revenue requirements were determined by a five-year forecast cost-of-service approach, but with a stretch factor of 0.6% applied to the Company's OM&A expenditures. The reduction to OM&A costs as a result of the stretch factor will accumulate for the five-year period. The rate smoothing deferral account (as required under Ontario Regulation 53/05) will stabilize year-to-year changes to weighted-average payment amounts as the Darlington Refurbishment continues. OPG will defer a portion of its approved nuclear revenue requirements into the rate-smoothing deferral account and will be allowed to recover the deferred amount, and any amount to be deferred from 2022–2026, over a ten-year period once the Darlington Refurbishment has been completed.
- The OEB reduced the nuclear OM&A budget by $100 million per year for a total of $500 million over five years. Additionally, the OEB did not approve for a mid-term review (prior to July 1, 2019) to update the nuclear production forecast.
- The OEB approved for the inclusion of $5.5 billion into the rate base over the five-year period of the Custom IR for the Darlington Refurbishment. Any cost overruns will be subject to a prudence review before being added to the rate base.
- The OEB also approved the recovery of balances as at December 31, 2015, in OPG's deferral and variance accounts.

• In December 2018 and February 2019, the OEB approved the Company's Application for 2019 Hydroelectric Payment Amount Adjustment and Recovery of Deferral and Variance Account Balances effective January 1, 2019.
  - The OEB approved a 1.1% base rate increase based on an inflation factor of 1.4%.
  - The OEB also approved for the recovery of balances as at December 31, 2017, in OPG's deferral and variance accounts.

Earnings and Outlook

(CAD millions where applicable)	For the year ended December 31 2018	2017	2016	2015	2014
Revenues	5,537	5,158	5,653	5,476	4,963
EBITDA 1	1,017	642	1,207	848	826
EBIT 1	233	(37)	(50)	(252)	72
Gross interest expense	301	296	298	293	300
Earning before taxes 1	225	(92)	(116)	(407)	36
Net income before non-recurring items 1	361	(14)	(106)	(271)	88
Reported net income	1,195	860	436	402	804
Return on equity	2.9%	-0.1%	-1.0%	-2.8%	1.0%
Hydroelectric rate base	N/A	N/A	7,447	7,490	7,526
Nuclear rate base	3,607	3,628	3,573	3,655	3,714
Approved regulated ROE	8.78%	8.78%	9.19%	9.30%	9.36%
Achieved regulated ROE	N/A	N/A	3.80%	2.67%	6.32%

1 Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.

2018 Summary

- EBITDA and EBIT increased significantly in 2018 largely because of the December 2017 approval of new rates by the OEB in a payment order dated March 2018 and effective June 1, 2017. EBITDA also benefitted from a full year's earnings from the Peter Sutherland Sr. GS, which was placed in service March 2017, and contributions from Eagle Creek, which was acquired in November 2018.
  - This was partly offset by (1) higher depreciation from the growing asset base and (2) higher hydroelectric foregone generation and outages compared with 2017.
- Tracking the stronger EBIT for the year, net income before non-recurring items also increased significantly in 2018. OPG also reported a corporate ROE of 9.5%. Excluding an after-tax $205 million gain on sale of the Lakeview GS site, this corporate ROE would still be at 7.8%, a large improvement from the adjusted 5.1% corporate ROE in 2017.
  - ROE of 7.8% would also be more in line with the allowed regulated ROE of 8.78%. DBRS notes the difference can be partly attributed to OPG's capitalization at around 35% versus the regulatory capital structure of 55% debt.

2019 Outlook

- Earnings for OPG are expected to remain relatively stable in 2019.
  - Effective January 1, 2019, base rates for the hydroelectric generation segment increased by 1.1%. Rates for the nuclear generation segment will increase as per the Custom IR decision.
- DBRS does not expect legislative changes to the Fair Hydro Plan by the Province to have a material financial impact on OPG. The Company is expected to continue to collect interest from its investment in the Fair Hydro Trust. DBRS notes that earnings from Fair Hydro Trust in 2018 were $27 million, increasing to $30 million in 2019 until the notes mature.
- Earnings volatility going forward will come from (1) forecast risk as part of the IR process and (2) macro factors such as weather, unexpected outages and Ontario's economic conditions.

Financial Profile

	For the year ended December 31				
(CAD millions where applicable)	2018	2017	2016	2015	2014
Net income before non-recurring items 4	361	(14)	(106)	(271)	88
Depreciation & amortization	784	679	1,257	1,100	754
Deferred income taxes and other	1,060	1,070	1,081	956	775
Cash flow (bef. working cap. changes)	**2,205**	**1,735**	**2,232**	**1,785**	**1,617**
Nuclear waste funding	(307)	(313)	(425)	(361)	(351)
Dividends paid	(283)	0	0	0	0
Capital expenditures	(1,826)	(1,853)	(1,816)	(1,376)	(1,545)
Free cash flow (bef. working cap. changes)	**(211)**	**(431)**	**(9)**	**48**	**(279)**
Changes in non-cash working cap. items	(160)	80	180	(129)	212
Change in regulatory assets/liabilities	(51)	(558)	(170)	170	(45)
Net free cash flow	**(422)**	**(909)**	**1**	**89**	**(112)**
Long-term investments	(358)	0	(213)	(180)	0
Proceeds on asset sales	289	554	110	3	0
Acquisition of Fair Hydro Trust receivables	(609)	(1,179)	0	0	0
Change in Fair Hydro Trust debt	306	601	0	0	0
Net equity change	268	519	0	0	0
Net debt change	622	458	(162)	(33)	165
Other	(17)	4	(14)	(25)	(5)
Change in cash	**79**	**48**	**(278)**	**(146)**	**48**
Total debt	7,878	6,579	5,522	5,684	5,730
Total debt 2	4,730	4,053	5,340	5,499	5,543
Cash & equivalents	349	418	398	464	610
Cash flow/Total debt 1, 2	45.0%	40.0%	40.6%	31.9%	28.7%
Total debt in capital structure 1, 2, 3	26.9%	26.2%	34.3%	35.8%	37.3%
EBIT gross interest coverage (times) 1, 2, 4	1.00	(0.24)	(0.14)	(0.86)	0.27
(Cash flow - n.w.f.)/Total debt 1, 2, 5	39.3%	33.7%	32.9%	25.4%	22.5%
Dividend payout ratio	78.4%	0.0%	0.0%	0.0%	0.0%

1 Including operating leases. 2 Excludes non-recourse debt. 3 Adjusted for accumulated other comprehensive income. 4 Excluding earnings from nuclear fixed-asset removal and nuclear waste management funds. 5 Includes nuclear waste funding (NWF) payments as they are not discretionary.

2018 Summary

- OPG's key credit metrics exclude non-recourse debt from UMH Energy Partnership (UMH; recourse released in 2014), Lower Mattagami Energy Limited Partnership (LMELP; rated A (high) with a Stable trend by DBRS; recourse released in 2017), Fair Hydro Trust and Eagle Creek.
  - The Company's cash flow-to-debt and debt-to-capital ratios remained strong in 2018, tracking the increase in earnings and cash flows. Additionally, the EBIT-interest coverage ratio improved significantly because of the stronger results for the year.
- Cash flow from operations increased largely because of the new regulated prices in place beginning March 2018.
- Capex remained elevated at $1.8 billion as OPG continued work on the Darlington Refurbishment.
- While the Company is not expected to make dividend payments to the Province during this period of high capex requirements, a special dividend was declared to transfer proceeds from the sale of the head office premises and associated parking facility to the Province.
- Long-term investments of $358 million represent the acquisition of Eagle Creek, which was completed in November 2018.
- Proceeds on asset sales largely represent the sale of the Lakeview GS site.
- The Fair Hydro Trust acquired $609 million of financing receivable assets from the IESO in 2018. This was funded with $306 million through a revolving warehouse facility (non-recourse to the Company), $268 million of equity injection from the Province and $35 million from OPG.

Financial Profile (CONTINUED)

- – Fair Hydro Trust issued $900 million of debt in 2018 to repay the revolving warehouse facility.
- The Company issued $600 million of debt to the OEFC and $450 million of Senior Notes under a Medium Term Note Program. The proceeds were partly used to refinance $395 million of debt owed to the OEFC and to fund OPG's portion of the Fair Hydro Trust financing receivable assets.

2019 Outlook

- OPG has planned capex of $2.1 billion for 2019, including approximately $1.3 billion for the Darlington Refurbishment.
- Cash flow from operations is expected to see a modest increase for the year, tracking the overall expected higher regulated rates.
  - – With no distributions expected in 2019, the Company should see a positive net free cash flow. As such, DBRS expects the Company's key credit metrics to strengthen modestly for the year.
- In February 2019, OPG issued $500 million of Senior Notes under its Medium Term Note Program. Proceeds from the offering were used partly to fund the Eagle Creek acquisition.

Long-Term Debt and Credit Facilities

(CAD millions)	Maturity	Dec. 31, 2018	Dec. 31, 2017
Notes payable to the OEFC	2019–2048	3,400	3,195
Medium Term Note Program	2027–2048	950	500
UMH Energy Partnership 1	2041	178	181
PSS Generating Station Limited Partnership 2	2067	245	245
Lower Mattagami Energy Limited Partnership 1	2021–2052	1,595	1,595
Fair Hydro Trust 1	2033–2038	900	601
Eagle Creek 1	2025–2030	323	0
Other		21	19
Subtotal		**7,612**	**6,336**
Less: Fair value discount		(31)	0
Less: Bond issuance fees		(25)	(17)
Less: Current portion		(368)	(398)
Total long-term debt		**7,188**	**5,921**

1 Non-recourse to OPG as debt is secured by assets of the associated project. 2 Secured by assets of the project; recourse to OPG until the recourse release date.

- 78% of the long-term debt issued at the parent level ($3.4 billion of $4.35 billion) is held by the OEFC, which is wholly owned by the Province. As a result, DBRS does not expect any material refinancing risk.
- In 2019, OPG issued $600 million of senior notes to the OEFC with a maturity date of 2048 and effective interest rates ranging from 3.87% to 4.00%.
  - – Proceeds were partly used to repay $395 million of notes to the OEFC that matured or will mature throughout the year.
- In June 2018, OPG issued $450 million of senior notes with a maturity date of 2048 and an effective interest rate of 3.84% under its Medium Term Note Program.
  - – In February 2019, the Company issued $500 million of senior notes with a maturity date of 2049 and an effective interest rate of 4.25%.
- The amortizing UMH notes were issued in 2009 with a maturity date of 2041 and an effective interest rate of 7.86%. The notes are secured by the assets of the Upper Mattagami and Hound Chute project and are non-recourse to OPG.
- The amortizing PSS GS notes were issued in 2015 with a maturity date of 2067 and an effective interest rate of 4.90%. The notes are secured by the assets of PSS GS and are recourse to OPG until the recourse release date (expected in 2020).
- The LMELP notes are secured by the assets of the project and are non-recourse to OPG.

Long-Term Debt and Credit Facilities (CONTINUED)

- Fair Hydro Trust senior notes are secured by the assets of the Fair Hydro Trust and are non-recourse to OPG.
  - In February 2018, Fair Hydro Trust issued $500 million of senior notes, maturing in 2033, to repay the majority of the balance under the revolving warehouse facility. In April 2018, an additional $400 million of senior notes, maturing in 2038, was issued.
- OPG assumed $323 million of long-term debt upon acquiring Eagle Creek. The notes are secured by assets of Eagle Creek and are non-recourse to the Company.

Maturity Profile

As at December 31, 2018

(CAD millions)	2019	2020	2021	2022	2023	Thereafter	Total
Long-term Debt	690	663	416	177	46	5,942	**7,934**
	9%	8%	5%	2%	1%	75%	**100%**

- OPG's maturity profile is fairly spread out.

Liquidity

Credit Facilities as at December 31, 2018

(CAD millions)	Maturity	Amount	Outstanding	Available
Committed credit facility - Tranche 1	20-May-23	500	170	330
Committed credit facility - Tranche 2	20-May-23	500	0	500
Short-term uncommitted credit facilities	Demand	476	404	72
Short-term uncommitted overdraft facilities	Demand	25	0	25
Lower Mattagami River Project - Tranche 1 [1]	17-Aug-23	300	195	105
Lower Mattagami River Project - Tranche 2 [1]	17-Aug-19	100	0	100
UMH Energy Partnership credit facilities [1]	15-Oct-19	16	15	1
UMH Energy Partnership overdraft facilities [1]	15-Oct-19	8	0	8
Total		**1,925**	**784**	**1,141**

1 Non-recourse to OPG as debt is secured by assets of the associated project.

- OPG has a reasonable liquidity profile.
- The Company has a $1.0 billion CP program backed by two tranches of bank facilities (extended due dates of May 20, 2023). OPG had $170 million of CP outstanding as at December 31, 2018.
- As at December 31, 2017, OPG had issued $404 million of letters of credit, about $364 million of which was attributed to its supplementary pension plan.
- The Company's $2,350 million credit facility provided by the OEFC matured at December 31, 2018. The Company is currently working with the OEFC for a new facility.
- The LMELP and UMH facilities are used to support the respective projects and are non-recourse to OPG.

Company Profile

As at December 31, 2018

Generation Portfolio

	Percent (%)	Capacity (MW)
Nuclear		
Darlington	*16%*	2,634
Pickering A	*6%*	1,030
Pickering B	*13%*	2,064
	35%	**5,728**
Thermal		
Atikokan (Biomass)	*1%*	205
Portlands Energy Centre 1	*2%*	275
Brighton Beach 1	*2%*	280
Lennox (Dual oil & gas)	*13%*	2,100
	18%	**2,860**
Hydroelectric		
Contracted 2	*8%*	1,280
Regulated	*39%*	6,426
	47%	**7,706**
Other (Wind) 3	*0%*	1
Total Capacity	**100%**	**16,295**

1 Represents OPG's share of in-service generation. 2 Includes plants under an ESA or a long-term contract. 3 One wind-power turbine.

- OPG is the largest generator of electricity in Ontario.
- In 2018, OPG generated 74.0 terawatt hours of electricity with total in-service capacity of 16,295 MW as at December 31, 2018.
  - The increase in generating capacity is largely attributed Eagle Creek, offset by the closure of the Thunder Bay biomass GS.
- OPG partnerships consist of the following:
  - OPG and ATCO Power Canada Ltd. co-own the Brighton Beach GS, a 560 MW natural gas-fired generating station.
  - OPG and TransCanada Energy Ltd. jointly own the Portlands Energy Centre, a 550 MW natural gas-fired generating station.
  - OPG owns the Bruce A and Bruce B nuclear GS, which are leased on a long-term basis to Bruce Power L.P. (rated BBB with a Stable trend by DBRS).
  - OPG and the Lac Seul First Nation (LSFN) jointly own the Lac Seul GS, with LSFN owning 25% of the facility.
  - OPG and the Moose Cree First Nation (MCFN), through its wholly owned subsidiary, Amisk-oo-Skow Finance Corporation, jointly own the Little Long, Harmon, Kipling and Smoky Falls GS, with MCFN owning 25% of the facilities.
  - OPG and Coral Rapids Power Corporation (CRP), a wholly owned subsidiary of the Taykwa Tagamou Nation, jointly own PSS GS, with CRP owning 33% of the facility.
  - OPG, a subsidiary of the Six Nations of the Grand River Development Corporation and Mississaugas of the Credit First Nation jointly own the Nanticoke Solar facility (in service March 2019), with OPG owning 80% of the facility.

Ontario Power Generation Inc.

(CAD millions)	December 31				December 31		
Assets	**2018**	**2017**	**2016**	**Liabilities & Equity**	**2018**	**2017**	**2016**
Cash & equivalents	349	418	398	S.T. borrowings	322	260	2
Accounts receivable	483	369	429	Accounts payable	1,161	1,228	1,164
Inventories	397	412	410	Current portion L.T.D.	368	398	1,103
Regulatory assets	490	0	0	Regulatory liabilities	36	0	0
Prepaid expenses & other	419	365	520	Deferred revenue & other	46	92	135
Total Current Assets	**2,138**	**1,564**	**1,757**	**Total Current Liab.**	**1,933**	**1,978**	**2,404**
Net fixed assets	22,987	21,322	19,998	Long-term debt	7,188	5,921	4,417
Intangibles	363	133	99	Deferred income taxes	1,018	879	829
Financing receivables	1,788	1,179	0	Pension & post-retirement benefits	6,339	6,515	5,909
Nuclear removal/waste mgmt. funds	17,464	16,701	15,960	Nuclear removal/waste mgmt. funds	21,225	20,421	19,484
Regulatory assets	6,769	7,231	5,855	Regulatory liabilities	762	594	310
Investments, materials & other	743	692	703	Payables & other L.T. liab.	660	603	511
				Shareholders' equity	13,127	11,911	10,508
Total Assets	**52,252**	**48,822**	**44,372**	**Total Liab. & SE**	**52,252**	**48,822**	**44,372**

Balance Sheet & Liquidity & Capital Ratios	For the year ended December 31				
	2018	**2017**	**2016**	**2015**	**2014**
Current ratio	1.11	0.79	0.73	1.33	1.09
Total debt in capital structure	37.5%	35.6%	34.4%	36.1%	37.7%
Total debt in capital structure 1, 2, 3	26.9%	26.2%	34.3%	35.8%	37.3%
Cash flow/Total debt	28.0%	26.4%	40.4%	31.4%	28.2%
Cash flow/Total debt 1, 2	45.0%	40.0%	40.6%	31.9%	28.7%
(Cash flow - dividends)/Capex (times)	1.05	0.94	1.23	1.30	1.05
(Cash flow - n.w.f.)/Total debt 1, 2, 5	39.3%	33.7%	32.9%	25.4%	22.5%
Dividend payout ratio	78.4%	0.0%	0.0%	0.0%	0.0%
Coverage Ratios (times)					
EBIT gross interest coverage 4	0.77	(0.13)	(0.17)	(0.86)	0.24
EBIT gross interest coverage 1, 2, 4	1.00	(0.24)	(0.14)	(0.86)	0.27
EBITDA gross interest coverage 4	3.38	2.17	4.05	2.89	2.75
Fixed-charges coverage 4	0.77	(0.13)	(0.17)	(0.86)	0.24
Profitability Ratios					
EBITDA margin 4	18.4%	12.4%	21.4%	15.5%	16.6%
EBIT margin 4	4.2%	-0.7%	-0.9%	-4.6%	1.5%
Profit margin 4	6.5%	-0.3%	-1.9%	-5.0%	1.8%
Return on equity 4	2.9%	-0.1%	-1.0%	-2.8%	1.0%
Return on capital 1, 3, 4	2.2%	0.5%	0.1%	-0.8%	1.4%

1 Including operating leases. 2 Excludes non-recourse debt. 3 Adjusted for accumulated other comprehensive income. 4 Excluding earnings from nuclear fixed-asset removal and nuclear waste management funds. 5 Includes NWF payments as they are not discretionary.

Rating History

Debt	Current	2018	2017	2016	2015	2014
Issuer Rating	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Unsecured Debt	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Commercial Paper Limit

- $1.0 billion.

Previous Report

- Ontario Power Generation: Rating Report, April 26, 2018.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrs.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

The DBRS group of companies consists of DBRS, Inc. (Delaware, U.S.)(NRSRO, DRO affiliate); DBRS Limited (Ontario, Canada)(DRO, NRSRO affiliate); DBRS Ratings GmbH (Frankfurt, Germany)(CRA, NRSRO affiliate, DRO affiliate); and DBRS Ratings Limited (England and Wales)(CRA, NRSRO affiliate, DRO affiliate). For more information on regulatory registrations, recognitions and approvals, please see: http://www.dbrs.com/research/highlights.pdf.

Rating Report

Saskatchewan Power Corporation

DBRS

Insight beyond the rating.

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Ratings

Debt	Rating	Rating Action	Trend
Long-Term Obligations*	AA	Confirmed	Stable
Short-Term Obligations*	R-1 (high)	Confirmed	Stable

* These obligations are based on the status of Saskatchewan Power Corporation (SaskPower) as a Crown agent of the Province of Saskatchewan (the Province) and reflect the Province's debt ratings.

Rating Update

DBRS Limited (DBRS) updated its report on Saskatchewan Power Corporation (SaskPower or the Company). The ratings assigned to the Company's Long- and Short-Term Obligations are a flow-through of the ratings of the Province of Saskatchewan (the Province; rated AA and R-1 (high) with Stable trends by DBRS; see DBRS's report on the Province dated June 1, 2018). Pursuant to *The Power Corporation Act* (the Act), SaskPower does not issue debt directly in the capital markets but obtains funding from the Government of Saskatchewan Ministry of Finance. Please see the DBRS methodology titled *Rating Canadian Provincial Agents of the Crown* for further detail. DBRS considers SaskPower to be self-supporting, as it can fund its own operations and service its debt obligations.

Following a period of weak profitability and rising leverage, SaskPower's key financial ratios and earnings profile strengthened in F2018. SaskPower has, over the past few years, applied for more moderate and gradual rate increases in order to avoid rate shock for customers. This placed pressure on the Company's key financial ratios, with leverage rising to 75.6% for F2017, above the Crown Investment Corporation (CIC)-approved long-term target of 60% to 75%. Profitability for SaskPower has also suffered, with the return on equity (ROE) for F2014 to F2017 ranging between 3.0% and 4.4%, significantly below the CIC-approved target of 8.5%. DBRS views the Company's plan to now apply for rate increases that will allow it to maintain leverage within the CIC-approved range and to earn the approved ROE as positive for its key financial ratios. The 3.5% rate increases effective January 1, 2017, and effective March 1, 2018, have helped improve ROE to 7.3% for F2018 and reduce leverage to 74.9%. The rate increases should also help fund the ongoing significant capital expenditures (capex) program to maintain aging infrastructure, connect new customers and meet growing demand (gross capex of $996 million for F2018; $886 million planned for F2019). DBRS expects incremental debt to finance the Company's capex program to continue to be funded by the Province. Pursuant to the Act, SaskPower is authorized to have outstanding borrowings of up to $10 billion ($3.2 billion unused as at June 30, 2018), including $2 billion by way of temporary loans through the Province which also includes $51 million of unsecured credit facilities at financial institutions.

DBRS notes there is also uncertainty on how a potential carbon tax regime may impact SaskPower's costs, and the resulting rate impacts. The Company has a large portfolio of coal generation facilities (34% of installed capacity and 44% of electricity generated in F2018), as well as gas generation. While recent changes in draft Federal carbon price regulations have reduced the expected cost, the overall rate impact is still expected to be substantial. The carbon levy is estimated to increase rates by an average of over 3% across customer classes in the 2019 calendar year and have a total impact on average electricity rates of over 5% by 2022. DBRS will continue to monitor developments of the carbon tax regime and any impact on SaskPower.

Financial Information

	12 mos. to June 30	For the year ended March 31			For the year ended December 31	
(CAD millions where applicable)	2018	2018	2017	2016	2014	2013
Total debt 1	7,299	7,218	6,995	6,711	5,928	5,143
Total debt in capital structure 1	74.8%	74.9%	75.6%	75.3%	73.1%	70.8%
Cash flow/Total debt 1	10.1%	9.8%	7.9%	7.8%	6.6%	9.6%
EBIT gross interest coverage (times)	1.60	1.57	1.33	1.37	1.21	1.62

Note: SaskPower changed its fiscal year-end to March 31. The first complete fiscal period consists of 15 months ended March 31, 2016.
1 Net of debt retirement funds.

Issuer Description

Established in 1929, SaskPower is Saskatchewan's leading energy supplier. SaskPower is responsible for over 534,000 customer accounts within Saskatchewan's geographic area of approximately 652,000 square kilometres. SaskPower operates three coal-fired power stations, seven hydroelectric stations, five natural gas stations and two wind power facilities. SaskPower also buys power from several partners. Combined, SaskPower's total available generation capacity is 4,493 megawatts (MW) of electricity.

Rating Considerations

Strengths

1. Debt is a direct obligation of the Province

The ratings assigned to the Company are a flow-through of the ratings of the Province. The Company's long- and short-term debt securities are direct obligations held by the Province.

2. Reasonable regulatory framework

The Company operates under a reasonable regulatory framework in Saskatchewan, where rate adjustment applications are reviewed by an independent rate review panel, which could render decisions in as few as 150 days from the date a rate application is submitted. The Saskatchewan Rate Review Panel (SRRP or the Panel) makes a recommendation on the application, with final approval coming from the provincial cabinet.

3. Dominant market position in Saskatchewan

SaskPower is the principal electric utility provider in Saskatchewan, servicing over 534,000 customer accounts.

Challenges

1. High level of planned capex

SaskPower has seen significantly higher capex over the past few years as the Company renewed its aging generation, transmission and distribution infrastructure. Capex for the medium term is expected to remain elevated, including an average of approximately $1 billion annually over the next three years. The Company has forecast capex of $886 million for F2019, with over 50% for growth and compliance projects.

2. Higher leverage

The Company's leverage has increased substantially over the past few years as a result of the Company's strategy of requesting for more moderate and gradual rate increases, despite the significant capex, in order to avoid rate shock for customers. While leverage decreased in F2018 to 74.9% and is now in the CIC-approved target range of 60% to 75%, it remains at the top of the range. Leverage for SaskPower is forecast to decrease modestly year over year as the Company plans to apply for rate increases that will be sufficient for it to earn its target ROE of 8.5%. Although no rate increases are planned for F2020, ROE is expected to improve to 8.5%. However, leverage will likely remain near the top of the range for at least the near-term and decrease over the medium-term to reach 67.6% by F2024.

3. High proportion of industrial customers

Industrial customers (including oilfields customers) represent a significant portion of SaskPower's customer base, accounting for approximately 63% of domestic power sales in gigawatt hours in F2018. This reliance on a segment that is sensitive to downturns in economic cycles introduces an additional degree of volatility into SaskPower's earnings.

4. Environmental concerns

The uncertainty and cost associated with future environmental compliance is high, given that as at March 31, 2018, 34% of SaskPower's available generating capacity was coal based and 75% was fossil fuel based. There is significant uncertainty regarding the implementation of a carbon tax in the Province. While recent changes in draft Federal carbon price regulations have reduced the expected cost, the overall rate impact is still expected to be substantial. The carbon levy is estimated to increase rates by an average of over 3% across customer classes in the 2019 calendar year and have a total impact on average electricity rates of over 5% by 2022. DBRS notes the environmental risk is partially mitigated by SaskPower's Boundary Dam Integrated Carbon Capture and Storage Project.

Earnings and Outlook

	12 mos. to June 30	For the year ended March 31			For the year ended December 31	
(CAD millions where applicable)	2018	2018	2017	2016	2014	2013
Revenues	2,632	2,584	2,401	2,885	2,155	2,042
Net sales	1,952	1,907	1,740	2,067	1,517	1,492
EBITDA	1,257	1,227	1,065	1,274	861	871
EBIT	707	684	571	703	472	516
Gross interest expense	442	437	429	515	390	318
Net income before non-recurring items	194	172	66	123	65	172
Reported net income	143	146	56	26	60	114
Actual return on equity	8.1%	7.3%	3.0%	4.4%	3.0%	8.3%
Rate base	9,939	9,895	9,518	9,140	8,548	7,641

Note: SaskPower changed its fiscal year-end to March 31. The first complete fiscal period consists of 15 months ended March 31, 2016.

2018 Summary

- SaskPower changed its fiscal year-end from December 31 to March 31, beginning in 2016. The first fiscal period reported by the Company includes the 15 months from January 1, 2015, to March 31, 2016.
- EBITDA and EBIT increased in F2018 because of (1) system-wide average rate increases of 3.5% effective January 1, 2017, and 3.5% effective March 1, 2018, (2) higher electricity sales volumes to domestic customers and (3) higher export volumes and sales prices.
  - This was partly offset by (1) higher depreciation because of the growing asset base and a change in the useful life of some assets following an internal depreciation study and (2) higher operating costs for the year because of increased maintenance activity at the generation facilities.
- Net income before non-recurring items increased significantly, returning to 2013 levels, tracking the higher EBITDA and EBIT.
- Reported net income included a $30 million write-down following a decision to defer development of the Tazi Twé Hydroelectric Project.
- While ROE of 7.3% remains below the CIC-approved target of 8.5%, it represents a significant improvement from the much weaker ROEs since 2014.

2019 Summary/Outlook

- EBITDA and EBIT increased in the last 12 months ending June 30, 2018 (LTM 2019), compared with F2018 because of (1) the above-mentioned rate increase, (2) higher electricity sales volumes to domestic customers and (3) stronger exports revenues because of higher sales prices and volumes.
  - This was partly offset by (1) higher operating costs for contract and consulting services and material supplies for overhaul maintenance at generation facilities, and (2) higher deprecation from the growing asset base.
- Reported net income includes $28 million related to environmental remediation provisions based on proposed estimated settlement costs for past activities.
- SaskPower has forecast net income of $207 million for F2019 for a ROE of 8.2%.
  - This improvement is because of (1) the above-mentioned rate increase and (2) expected higher exports to the Alberta market for the year.
- Going forward, DBRS expects SaskPower's earnings to be more stable as the Company intends to request rate increases that would allow it to earn the CIC-approved target ROE of 8.5%.
  - Volatility in earnings is expected to arise primarily due to changes in the fuel mix.
  - DBRS notes there is uncertainty how a potential carbon tax regime may affect SaskPower. Should the carbon tax significantly increase customer rates, this could negatively impact volumes and affect SaskPower's earnings and cash flows.

Financial Profile

	12 mos. to June 30	For the year ended March 31			For the year ended December 31	
(CAD millions where applicable)	2018	2018	2017	2016	2014	2013
Net income before non-recurring items	194	172	66	123	65	172
Depreciation & amortization	550	543	494	571	389	355
Deferred income taxes and other	(9)	(6)	(8)	(38)	(60)	(32)
Cash flow from operations	**735**	**709**	**552**	**656**	**394**	**495**
Dividends paid	0	0	0	0	0	0
Capital expenditures	(950)	(966)	(866)	(1,147)	(1,221)	(1,265)
Free cash flow (bef. working cap. changes)	**(215)**	**(257)**	**(314)**	**(491)**	**(827)**	**(770)**
Changes in non-cash work. cap. items	(104)	(1)	12	(247)	(3)	77
Net free cash flow	**(319)**	**(258)**	**(302)**	**(738)**	**(830)**	**(693)**
Net equity change	0	0	0	0	0	0
Net debt change	362	292	342	863	875	632
Other investing and financing	(40)	(40)	(55)	(95)	(45)	57
Change in cash	**3**	**(6)**	**(15)**	**30**	**0**	**(4)**
Total debt 1	7,299	7,218	6,995	6,711	5,928	5,143
Cash and equivalents	4	7	13	28	0	0
Total debt in capital structure 1	74.8%	74.9%	75.6%	75.3%	73.1%	70.8%
Cash flow/Total debt 1	10.1%	9.8%	7.9%	7.8%	6.6%	9.6%
EBIT gross interest coverage (times)	1.60	1.57	1.33	1.37	1.21	1.62
Dividend payout ratio	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Note: SaskPower changed its fiscal year-end to March 31. The first complete fiscal period consists of 15 months ended March 31, 2016.
1 Net of debt retirement funds.

2018 Summary

- SaskPower's key financial ratios improved in F2018 because of the stronger earnings and cash flows for the year.
  - While the Company's debt-to-capital ratio is now within the long-term target range of 60% to 75%, it is at the very high end of that range at 74.9%.
- Cash flow from operations increased significantly from F2017, tracking the higher income for the year.
- The Company spent $996 million on capital projects, with (1) $380 million for sustainment capex and (2) $578 million for growth and compliance capex, including $325 million on the Chinook Power Station.
  - The Chinook Power Station, a 350 MW combined cycle natural gas facility that has a budget of $680 million, remains on budget and on target to be in-service by October 2019.
- CIC has foregone dividends from the Company during this period of significant capex.
- SaskPower's negative net free cash flow was funded through debt issuances obtained from the Province.

2019 Summary/Outlook

- SaskPower's key financial ratios saw continued modest improvement in the LTM 2019 compared to F2018 because of the higher earnings and cash flows for the period.
- Capex remained elevated as the Company continued work on the Chinook Power Station.
- DBRS expects SaskPower's key financial ratios to continue improving modestly over the medium term as the Company intends to apply for rate increases that will allow it to meet the CIC-approved ROE target of 8.5%.
  - While leverage at SaskPower is expected to decrease slightly year over year and be within the long-term target range of 60% to 75% going forward, DBRS notes it will likely remain near the top of the range over the medium term.
- SaskPower has forecast capex of $886 million for F2019. DBRS expects the free cash flow deficit that will likely be generated from the continued high capital spending to be funded through incremental debt from the Province.

Long-term Debt Maturities and Bank Lines

Summary

- The Company has readily available access to additional funds. The Province supports SaskPower by borrowing in its behalf. As a result, SaskPower does not issue debt directly in the capital markets.
- *The Power Corporation Act* authorizes SaskPower to have outstanding borrowings of up to $10 billion ($3.2 billion unused as at June 30, 2018), of which $2 billion may be borrowed by way of temporary loans through the Province including $51 million of unsecured credit facilities at financial institutions.

	June 30	March 31			December 31
(CAD millions)	**2018**	**2018**	**2017**	**2016**	**2015**
Long-term debt:					
Recourse debt	5,550	5,550	5,500	5,050	4,850
Non-recourse debt & unamort. premiums net of issue costs	70	71	59	80	104
Finance lease obligations	1,110	1,114	1,126	1,133	1,136
Total long-term debt	**6,730**	**6,735**	**6,685**	**6,263**	**6,090**
Bank indebtedness	0	0	0	0	2
Short-term advances	1,252	1,141	900	981	950
Total debt	**7,982**	**7,876**	**7,585**	**7,244**	**7,042**
Debt retirement funds	(683)	(658)	(590)	(533)	(511)
Total debt less debt retirement funds	**7,299**	**7,218**	**6,995**	**6,711**	**6,531**

- In F2018, SaskPower borrowed $168 million in long-term debt and $241 million in short-term advances to finance capex and repaid $105 million in long-term debt.
- The Company borrowed an additional $111 million in short-term advances in the first quarter of F2019, with the majority of the funds used to fund ongoing capex.
- For certain advances from the Province, SaskPower is required to contribute amounts equal to at least 1% of the outstanding balance into debt retirement funds administrated by the Ministry of Finance.

Upcoming Debt Maturities

(CAD millions – as at March 31, 2018)	**2018-19**	**2019-20**	**2020-21**	**2021-22**	**2022-23**	**Thereafter**
Principal debt repayments	5	5	134	245	261	4,971
Debt retirement funds installments	55	55	55	54	52	961
Future minimum lease payments	179	183	187	191	194	1,873

- The debt maturity profile is reasonably spread out, with only $650 million of total debt, of which a portion will be funded from sinking funds, maturing prior to F2023.

Regulation

- SaskPower is governed by *The Power Corporation Act* and is subject to provisions under *The Crown Corporations Act, 1993*. The current regulatory model allows SaskPower to request rate adjustments for review by the SRRP, with final approval by the provincial cabinet (the Cabinet). At a minimum, the process takes approximately 150 days before a decision is rendered.
- Unlike other provincial utility commissions, the Panel does not specifically set an allowed rate of return or capital structure for SaskPower. The Panel only considers ROE, capital structure, rate base and capital allocation as provided and decides whether the proposed changes to the rates are reasonable in the context of SaskPower's forecast delivery cost of service.
- SaskPower currently targets a ROE of 8.5% and equity thickness of 25% to 40%.
- In May 2016, the Panel announced a review of the Company's request for system-average rate increases of 5.0% effective July 1, 2016, and 5.0% effective January 1, 2017.
    - The Cabinet approved an interim system-average rate increase of 5.0% effective July 1, 2016.
    - In November 2016, the SRRP issued a recommendation for the Cabinet to confirm the system-average rate increase of 5.0% effective July 1, 2016, and approve a 3.5% increase effective January 1, 2017.
    - In December 2016, the Cabinet approved the rate increases as per the SRRP recommendations.
- In August 2017, SaskPower submitted its request to the Panel for a flat rate increase of 5.1% across all customer classes (except contract customers) effective March 1, 2018.
    - In January 2018, the SRRP issued a recommendation for the Cabinet to approve a 3.5% increase effective March 1, 2018.
    - The Cabinet approved the rate increases as per the SRRP recommendations on January 24, 2018.
- There are currently no plans for a market restructuring in Saskatchewan.
- The Open Access Transmission Tariff (OATT) opened the provincial transmission system to wholesale energy suppliers and users and also improved SaskPower's access to the transmission systems of other electrical utilities, thereby enhancing the Company's trading and export opportunities.

Province of Saskatchewan

(Excerpt from DBRS Rating Report dated June 1, 2018. Please see report for more detail.)

DBRS Limited (DBRS) confirmed the Issuer Rating and Long-Term Debt and Short-Term Debt ratings of the Province of Saskatchewan (Saskatchewan or the Province) at AA, AA and R-1 (high), respectively. All trends are Stable. The Province's fiscal position was challenged by the downturn in the commodity sector, but the economic and fiscal recovery are now well underway, and the outlook for budgetary results and debt have improved significantly, providing greater flexibility to the credit profile.

Saskatchewan Power Corporation

(CAD millions)	June 30 2018	March 31 2018	March 31 2017		June 30 2014	March 31 2013	March 31 2012
Assets				**Liabilities & Equity**			
Cash & equivalents	4	7	13	S.T. borrowings	1,252	1,141	900
Accounts receivable	527	540	458	Accounts payable	382	534	429
Inventories	221	214	214	Current portion L.T.D.	24	23	119
Risk management assets	5	10	11	Risk management liab.	157	166	141
Prepaid expenses & other	19	21	16	Other current liab.	98	59	58
Total Current Assets	**776**	**792**	**712**	**Total Current Liab.**	**1,913**	**1,923**	**1,647**
Net fixed assets	9,939	9,895	9,518	Long-term debt	6,706	6,712	6,566
Goodwill & intangibles	61	63	48	Employee future benefits	191	210	237
Debt retirement funds	683	658	590	Provisions & other liab.	261	233	217
Investments & others	46	48	40	Shareholders' equity	2,434	2,378	2,241
Total Assets	**11,505**	**11,456**	**10,908**	**Total Liab. & SE**	**11,505**	**11,456**	**10,908**

Balance Sheet & Liquidity & Capital Ratios	12 mos. to June 30 2018	For the year ended March 31 2018	For the year ended March 31 2017	For the year ended March 31 2016	For the year ended December 31 2014	For the year ended December 31 2013
Current ratio	0.41	0.41	0.43	0.40	0.35	0.34
Total debt in capital structure	76.5%	76.5%	77.0%	76.6%	74.5%	72.2%
Total debt in capital structure 1	74.8%	74.9%	75.6%	75.3%	73.1%	70.8%
Cash flow/Total debt	9.2%	9.0%	7.3%	7.2%	6.2%	9.0%
Cash flow/Total debt 1	10.1%	9.8%	7.9%	7.8%	6.6%	9.6%
(Cash flow-dividends)/Capex (times)	0.77	0.73	0.64	0.57	0.32	0.39
Dividend payout ratio	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Coverage Ratios (times)						
EBIT gross interest coverage	1.60	1.57	1.33	1.37	1.21	1.62
EBITDA gross interest coverage	2.84	2.81	2.48	2.47	2.21	2.74
Fixed-charges coverage	1.60	1.57	1.33	1.37	1.21	1.62
Profitability Ratios						
EBITDA margin	64.4%	64.3%	61.2%	61.6%	56.8%	58.4%
EBIT margin	36.2%	35.9%	32.8%	34.0%	31.1%	34.6%
Profit margin	9.9%	9.0%	3.8%	6.0%	4.3%	11.5%
Return on equity	8.1%	7.3%	3.0%	4.4%	3.0%	8.3%
Return on capital	6.0%	5.8%	5.0%	5.2%	4.9%	6.3%

Note: SaskPower changed its fiscal year-end to March 31. The first complete fiscal period consists of 15 months ended March 31, 2016.
1 Net of debt retirement funds.

Operating Statistics

		For the year ended March 31			For the year ended December 31	
Electricity Sold — Breakdown (GWh)		**2018**	**2017**	**2016**	**2014**	**2013**
Residential	14%	3,162	3,068	3,963	3,281	3,190
Commercial	17%	3,862	3,777	4,773	3,788	3,663
Oilfields	18%	3,877	3,621	4,402	3,503	3,448
Industrial	45%	9,845	9,207	11,107	8,179	7,863
Farm	6%	1,328	1,189	1,594	1,364	1,332
Total Domestic	**100%**	**22,074**	**20,862**	**25,839**	**20,115**	**19,496**
Plus: Exports		304	176	113	90	497
Plus: Reseller		1,208	1,218	1,543	1,274	1,257
Total Sold		**23,586**	**22,256**	**27,495**	**21,479**	**21,250**
Energy sales growth (annualized)		6.0%	2.4%	1.4%	1.1%	6.5%
Generation (MW)						
Hydroelectricity	20%	889	889	889	864	863
Coal	34%	1,530	1,530	1,530	1,530	1,591
Natural gas	40%	1,824	1,824	1,771	1,567	1,597
Wind	5%	221	221	221	198	198
Other	1%	29	27	26	22	32
Total Installed Capacity	**100%**	**4,493**	**4,491**	**4,437**	**4,181**	**4,281**
Net Energy Supplied (GWh)						
Hydroelectricity	15%	3,873	3,525	4,285	4,706	4,449
Coal	44%	10,864	10,759	13,882	10,219	10,846
Natural gas	37%	9,144	8,729	10,378	6,883	6,460
Wind	3%	765	740	876	636	646
Other	1%	156	143	180	183	206
Gross Energy Generated	**100%**	**24,802**	**23,896**	**29,601**	**22,627**	**22,607**
Plus: Imports		515	478	573	797	548
Energy Generated and Purchased		**25,317**	**24,374**	**30,174**	**23,424**	**23,155**
Less: Line losses		(1,731)	(2,118)	(2,679)	(1,945)	(1,905)
Net Sold		**23,586**	**22,256**	**27,495**	**21,479**	**21,250**
Energy lost/energy generated + purchased		6.8%	8.7%	8.9%	8.3%	8.2%
Maximum primary peak demand (net MW)		3,792	3,747	3,640	3,561	3,543
Peak demand/installed capacity		84.4%	83.4%	82.0%	85.2%	82.8%
Export Interconnections (MW)						
Manitoba Hydro-Electric Board		90	90	90	90	5
Alberta Power Limited		153	153	153	153	153
U.S. — Basin Electric		150	150	100	100	105
Total		**393**	**393**	**343**	**343**	**263**

Note: SaskPower changed its fiscal year-end to March 31. The first complete fiscal period consists of 15 months ended March 31, 2016.

Rating History

	Current	2017	2016	2015	2014	2013
Long-Term Obligations*	AA	AA	AA	AA	AA	AA
Short-Term Obligations*	R-1 (high)	R-1 (high)	R-1 (high)	R-1 (high)	R-1 (high)	R-1 (high)

* These obligations are based on the status of Saskatchewan Power Corporation (SaskPower) as a Crown agent of the Province of Saskatchewan (the Province) and reflect the Province's debt ratings.

Previous Action

- Confirmed, June 1, 2018.

Related Research

- "DBRS Confirms Province of Saskatchewan at AA and R-1 (high)," June 1, 2018.
- Saskatchewan, Province of: Rating Report, June 1, 2018.

Previous Report

- Saskatchewan Power Corporation: Rating Report, November 20, 2017.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrs.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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Rating Report

The Manitoba Hydro-Electric Board

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Insight beyond the rating.

Ratings

Debt	Rating	Trend
Long-Term Obligations	A (high)	Stable
Short-Term Obligations	R-1 (middle)	Stable

Note: These Obligations are based on the status of the Manitoba Hydro-Electric Board as a Crown agent of the Province of Manitoba and the unconditional guarantee provided by the Province on Manitoba Hydro's third-party debt and thus reflect the Province's debt ratings.

Rating Update

DBRS Limited (DBRS) updated its report on the Manitoba Hydro-Electric Board (Manitoba Hydro or the Utility). The ratings assigned to the Utility's Long-Term Obligations and Short-Term Obligations are a flow-through of the ratings of the Province of Manitoba (the Province; rated A (high) and R-1 (middle) with Stable trends by DBRS). Pursuant to *The Manitoba Hydro Act*, the Province unconditionally guarantees almost all of Manitoba Hydro's outstanding third-party debt. Please see the *DBRS Criteria: Guarantees and Other Forms of Support* methodology for further details. The Province also provides most of the Utility's financing through provincial advances (approximately 99% of total debt as at March 31, 2017). DBRS considers Manitoba Hydro to be self-supporting, as it is currently able to fund its own operations and service debt obligations.

In May 2017, Manitoba Hydro filed its 2017/18 and 2018/19 General Rate Application (GRA) with the Manitoba Public Utilities Board (PUB), requesting 7.9% rate increases effective August 1, 2017, and April 1, 2018. The application is in line with the Utility's new 10-year plan to return to financial health through higher rate increases and a Voluntary Departure Program (VDP) for 15% of total staff (825 employee departures) in order to strengthen the balance sheet back to the target capital structure of 75% debt (debt-to-capital was 84.9% as at September 30, 2017). DBRS finds the application, and the 10-year plan, to be encouraging as, if approved, the rate increases will help alleviate pressure on Manitoba Hydro's financial profile during this period of significant capital expenditures (capex) for the Bipole III Transmission Reliability Project (Bipole III; total capex of $5.0 billion) and the Keeyask Infrastructure and Generating Station Project (the Keeyask Project; total capex of $8.7 billion). However, DBRS notes that the PUB only approved an interim rate increase of 3.36% effective August 1, 2017. Should the PUB approve final rates for F2018 that are also significantly below the applied-for 7.9%, this will likely result in further deterioration in the Utility's balance sheet.

DBRS views Manitoba Hydro as self-supporting, as its earnings and cash flows are currently sufficient to cover its operating expenses and service its outstanding debt. However, DBRS could

Continued on P.2

Financial Information

(CAD millions where applicable)	12 mos. ended Sept. 30 2017	For the year ended March 31 [1] 2017	2016	2015	2014	2013
Total debt in capital structure [2]	84.9%	84.3%	83.0%	81.3%	79.4%	78.5%
Cash flow/Total debt	4.8%	5.3%	5.4%	5.3%	6.4%	6.1%
EBIT gross interest coverage (times)	1.00	0.97	0.98	1.13	0.96	0.89
Net income before non-recurring items	99	72	55	145	178	92
Cash flow from operations	805	872	784	665	691	589

1 2015 to 2017 based on IFRS; 2013 and 2014 based on Canadian GAAP. 2 Adjusted for other comprehensive income.

Issuer Description

Manitoba Hydro, a wholly owned Crown corporation of the Province, is a vertically integrated electric utility that provides generation, transmission and distribution of electricity to approximately 573,438 customers throughout Manitoba and natural gas service to approximately 279,268 customers via its subsidiary, Centra Gas Manitoba Inc. (Centra Gas). The Utility also exports electricity to more than 25 electric utilities through its participation in four wholesale markets in Canada and in the midwestern United States.

Rating Update (CONTINUED)

consider reclassifying a portion of the Utility's debt to be tax-supported should the financial health of the Utility deteriorate to the point where its expenses cannot be recovered through rates; this could potentially arise if rate increases are insufficient to recover Manitoba Hydro's costs. If this were to occur, it could potentially put downward pressure on the Province's credit rating. Similarly, a large equity injection by the Province that materially increases tax-supported debt could also put downward pressure on the Province's credit profile. At this time, however, DBRS expects the Province's ratings to remain stable.

Rating Considerations

Strengths

1. Debt is a direct obligation of the Province
Manitoba Hydro is an agent of the Crown and its debt securities, with the exception of $65 million of Manitoba Hydro-Electric Board Bonds (less than 1% of total debt as at March 31, 2017), are held or guaranteed by the Province; therefore, the ratings assigned to Manitoba Hydro's obligations are a flow-through of the ratings assigned to the Province.

2. Low-cost hydroelectric-based generation
Low-cost hydroelectric-based generating capacity results in one of the lowest variable cost structures in North America, which has enabled Manitoba Hydro to provide electricity to its domestic customers at one of the lowest rates on the continent. This gives the Utility the flexibility to increase rates in the future, especially in light of the substantially heightened capex requirements.

3. Access to export markets
Manitoba Hydro's interconnections (approximately 44% of installed capacity), with firm export transfer capability of 2,100 megawatts (MW) to the United States, 175 MW to Saskatchewan and 200 MW to Ontario, along with additional non-firm transfer capability, provide the Utility with access to favourable export markets. The interconnections also provide a secure supply of electricity for domestic customers during times of poor hydrology.

Challenges

1. High leverage
Leverage at Manitoba Hydro has been increasing over the past few years as a result of the significant capital projects currently being undertaken. As such, the debt-to-capital ratio reached 84% as at F2017, above the target capital structure of 75% debt. The Utility had forecast leverage to peak at slightly above 85% when the Keeyask Project is brought in service, but with the possibility of lower approved rate increases, leverage could potentially further increase if mitigants are not enacted. DBRS notes that initiatives undertaken by the Utility, such as the VDP, are encouraging and should help to partially alleviate pressure on key financial ratios.

2. High level of planned capex
The Utility is currently undergoing a period of substantial capex, with major projects that include Bipole III (total capex of approximately $5.0 billion) and the Keeyask Project (total capex of approximately $8.7 billion). As a result, capex for the Utility has been forecast to average approximately $2.2 billion per year before reducing to $700 million beginning in F2024. However, should the projects encounter further cost overruns or delays, total capex will likely increase.

3. Hydrology risk
Given that approximately 92% of Manitoba Hydro's installed generating capacity is hydroelectricity-based, earnings and cash flows are highly sensitive to hydrological conditions. The Utility is also exposed to significant price and volume risk because of its export commitments under the fixed price-to-volume contract that may require the Utility to procure power supply from import markets if hydrological conditions are unfavourable.

Major Projects (Under Construction and Planned)

Project	Estimated Cost ($ millions)	Planned Construction Start Date	In-Service Target Date
Bipole III Transmission Reliability Project	5,040	2013	2018
Keeyask Infrastructure and Generating Station Projects	8,700	2014	2021
Manitoba-Minnesota Transmission Project	453	2017	mid-2020

- **Bipole III:** This project involves the construction of a 500-kilovolt (kV) high-voltage direct current transmission line, along with new converter stations. Construction began during winter 2013/2014, and the transmission line is expected to be in service for July 2018.
- **The Keeyask Project:** This project includes the development of a 695 MW generation station on the Nelson River. Construction began in July 2014; the generators are expected to be in service by August 2021.
- **Manitoba-Minnesota Transmission Project:** This proposed project involves the construction of a 500 kV alternating current transmission line from Winnipeg to the Manitoba-Minnesota border, where it will interconnect with the Great Northern Transmission Line (GNTL) to be built by Minnesota Power. The Province authorized Manitoba Hydro to proceed with the project in July 2014, and the Utility filed an Environmental Impact Statement in September 2015, which began the formal regulatory review process. Minnesota Power has received all major regulatory approvals for the GNTL, including a Presidential Permit, and construction began in 2017. The transmission line is expected to be in service for June 2020.

Earnings and Outlook

	12 mos. ended Sept. 30	For the year ended March 31 [1]				
(CAD millions where applicable)	2017	2017	2016	2015	2014	2013
Total electricity revenues	2,003	1,881	1,791	1,812	1,861	1,733
Net gas revenues	335	159	172	161	163	147
Total revenues	**2,338**	**2,040**	**1,963**	**1,973**	**2,024**	**1,880**
EBITDA	1,135	1,093	1,030	1,028	1,068	991
EBIT	723	688	642	659	626	568
Gross interest expense	720	711	654	581	654	636
Earning before taxes	86	60	45	134	156	79
Net income before non-recurring items	99	72	55	145	178	92
Reported net income	54	71	49	136	174	92
Return on equity [2]	4.4%	2.4%	1.9%	5.0%	6.6%	3.5%

1 2015 to 2017 based on IFRS; 2013 and 2014 based on Canadian GAAP. 2 Adjusted for other comprehensive income.

F2017 Summary

- Earnings increased in F2017, largely as a result of (1) domestic customer growth and an interim 3.36% rate increase effective August 1, 2016, and (2) higher export sales from new long-term contracts and from favourable water conditions.
  - The increase was partly offset by (1) higher finance expense from the increasing debt used to fund the large capex program, (2) higher fuel and power purchased costs and (3) higher capital taxes.

F2018 Outlook

- Earnings for Manitoba Hydro increased in the last 12 months ending September 30, 2017, as (1) favourable water conditions resulted in stronger extraprovincial revenues and (2) growth in domestic electricity volumes.
- However, Manitoba Hydro has forecast net income to decrease in F2018 to approximately $40 million as (1) the PUB approved an interim rate increase of 3.36% effective August 1, 2017, rather than the applied-for 7.9%, (2) continued weak export prices and (3) a dry summer impacting water conditions.
- DBRS expects Manitoba Hydro's profitability to remain challenged over the medium term as the Utility continues to invest significant amounts into Bipole III and the Keeyask Project. However, the new board at Manitoba Hydro appointed in 2016 intends to improve leverage at the Utility back to the target debt-to-capital ratio of 75% within a ten-year timeframe.
  - As outlined in its ten-year plan, Manitoba Hydro has filed an application with the PUB for a rate increase of 7.9% effective April 1, 2018, significantly higher than the previously planned rate increase requests of 3.95%. The Utility plans to file for annual rate increases of 7.9% until F2024, when it will decrease to 4.54%, followed by two years of 2% increases.
  - DBRS finds the rate application to be encouraging as the previously planned rate requests of 3.95% were expected to be insufficient for Manitoba Hydro to recover costs related to major projects for the medium term and were forecast to result in negative net income for a few years.
  - DBRS also considers the VDP to be a positive initiative for Manitoba Hydro's earnings as it is expected to result in annual savings of $90 million.

Financial Profile

	12 mos. ended Sept. 30	For the year ended March 31 [1]				
(CAD millions where applicable)	2017	2017	2016	2015	2014	2013
Cash receipts from customers		2,314	2,331	2,359	2,176	2,015
Cash paid to suppliers and employees		(875)	(988)	(1,203)	(1,053)	(981)
Interest paid		(584)	(582)	(517)	(502)	(489)
Interest received		17	23	26	70	44
Cash flow from operations	**805**	**872**	**784**	**665**	**691**	**589**
Dividends paid	0	0	0	0	0	0
Capital expenditures	(2,994)	(2,912)	(2,269)	(1,730)	(1,394)	(1,037)
Free cash flow	**(2,189)**	**(2,040)**	**(1,485)**	**(1,065)**	**(703)**	**(448)**
Acquisitions & investments	31	12	(4)	(105)	(103)	(98)
Net sinking fund withdrawals/(payments)	0	0	114	(3)	206	22
Net debt change	2,136	1,866	1,803	1,556	707	565
Other	(444)	(147)	33	(31)	3	(59)
Change in cash	**(466)**	**(309)**	**461**	**352**	**110**	**(18)**
Total debt (net sinking fund investments)	16,887	16,438	14,527	12,566	10,757	9,633
Cash and equivalents	614	641	952	487	142	32
Total debt in capital structure [2]	84.9%	84.3%	83.0%	81.3%	79.4%	78.5%
Cash flow/Total debt	4.8%	5.3%	5.4%	5.3%	6.4%	6.1%
EBIT gross interest coverage (times)	1.00	0.97	0.98	1.13	0.96	0.89
Dividend payout ratio	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

1 2015 to 2017 based on IFRS; 2013 and 2014 based on Canadian GAAP. 2 Adjusted for other comprehensive income.

F2017 Summary

- Manitoba Hydro's key financial ratios saw modest deterioration in F2017, largely as a result of the significant increase in debt. Overall, DBRS considers the Utility's ratios as weak, with leverage high at 84.3%, and EBIT-interest coverage below 1.00 times (x) at 0.97x.
- Cash flow from operations increased because of higher payable balances related to the capex projects.
- Gross capex of $3.0 billion included $1.4 billion for Bipole III and $904 million for the Keeyask Project.
- The significant free cash flow deficit for the fiscal period was funded through advances from the Province.

F2018 Outlook

- Manitoba Hydro's key financial ratios are expected to remain weak over the medium term. The Utility expects its leverage to peak in 2020, at just above 85%. DBRS notes this is an improvement from the previous forecast, where the debt-to-capital ratio was expected to peak at 88% in F2022. DBRS considers the higher applied-for rate increases, as well as the VDP, to be encouraging and should help improve the Utility's financial health.
  - However, DBRS remains concerned that if the PUB approves a rate increase lower than the applied-for 7.9%, Manitoba Hydro's key financial ratios will likely see further deterioration. Should the Utility's earnings and cash flows deteriorate to a point where it is no longer able to cover operating expenses and to service outstanding debt, or the Utility's financial health deteriorates to a point where expenses cannot be fully recovered through rates, DBRS could consider reclassifying a portion of Manitoba Hydro's debt to be tax-supported.
- Manitoba Hydro has forecast capex of approximately $3.3 billion for F2018, including around $1.2 billion for Bipole III and $1.1 billion for the Keeyask Project.
  - The Utility has forecast capex to peak in F2019, and will decrease following the in-service of Bipole III in F2018, before moderating to around $750 million per year following the in-service of the Keeyask Project.
- The high level of capex is expected to result in continued negative free cash flows, which will likely be funded through advances from the Province. DBRS notes that the Utility does have some financial flexibility, as it has no mandatory dividend payment requirements.

Long-Term Debt Maturities and Bank Lines

Debt Profile

		For the year ended March 31		
(CAD millions)	%	2017	2016	2015
Advances from the Province	99.1%	16,341	14,437	12,485
Manitoba Hydro Bonds	0.0%	7	26	76
Manitoba Hydro-Electric Board Bonds*	0.9%	145	145	157
	100.0%	**16,493**	**14,608**	**12,718**
Other adjustments		(55)	(81)	(38)
Total		**16,438**	**14,527**	**12,680**

* Includes $65 million of unguaranteed bonds at March 31, 2017.

Debt Maturities

Year	2018	2019	2020	2021	2022	Thereafter	Total
(CAD millions)	336	996	374	1,308	1,119	12,359	**16,492**
%	2%	6%	2%	8%	7%	75%	**100%**

Summary

- The Province supports Manitoba Hydro by advancing funds or guaranteeing the Utility's long-term debt issuances. Long-term debt as at March 31, 2017, consisted of the following:
  - $16,341 million in advances from the Province (all of which have annual sinking fund requirements).
  - $7 million of Manitoba Hydro Bonds.
  - $145 million of Manitoba Hydro-Electric Board Bonds.
- Only $65 million of Manitoba Hydro-Electric Board Bonds, which were issued for mitigation projects, do not carry the provincial guarantee.
- Manitoba Hydro maintains a relatively smooth maturity profile with potential volatility from foreign currency debt, mostly mitigated through natural and cash flow hedges and a moderate level of floating-rate debt (6% of total debt as at March 31, 2017), which adds stability to debt servicing costs and minimizes interest rate risk.
- The Utility has bank credit facilities that provide for overdrafts and notes payable of up to $500 million denominated in Canadian and/or U.S. dollars. As at March 31, 2017, there were no amounts outstanding. Manitoba Hydro issues short-term promissory notes in its own name for its short-term cash requirements and does not receive short-term funding from the Province. These short-term notes are guaranteed by the Province.

Regulation

Manitoba Hydro is governed by *The Manitoba Hydro Act* and its electricity and natural gas rates are regulated by the PUB.

Electricity

- Each year, Manitoba Hydro reviews its financial targets with particular focus on its debt-to-equity target capital structure of 75% to 25%. If the Utility deems a rate adjustment necessary to continue progress toward attaining its financial targets, it submits a rate application to the PUB.
- The PUB reviews the rate adjustment application with the objective of allowing Manitoba Hydro to recover its cost of service and achieve its long-term debt-to-equity target. Historically, the PUB did not have the mandate to review the Utility's capex; however, the Province issued Order in Council 92 in May 2017, tasking the PUB with reviewing Manitoba Hydro's capex.
- Manitoba Hydro submitted its 2017/18 and 2018/19 GRA in May 2017, requesting 7.9% rate increases effective August 1, 2017, and April 1, 2018.
  - The rate application followed the Utility's ten-year plan to return to financial health. Manitoba Hydro had originally filed for rate increases of 7.9% for five years followed by 2% thereafter. Additionally, the Utility initiated a VDP to reduce staff by 15% (around 825 employee departures) by January 2018.
  - The PUB approved an interim 3.36% rate increase effective August 1, 2017. Following the interim rate increase, the Utility updated its forecast and now plans to file for rate increases of 7.9% annually for six years, before decreasing to 4.54% for F2025, followed by two years of 2% increases. Together with the VDP, these initiatives are expected, if realized, to return Manitoba Hydro to its target capital structure of 75% debt in F2027.
  - A final decision is not expected until April 2018, at the earliest.
- While Manitoba Hydro is the sole retail electricity supplier in Manitoba, under *The Manitoba Hydro Amendment Act* (the Act), other utilities may access the transmission system to reach customers in neighbouring provinces and states.
- The Act also explicitly allows Manitoba Hydro to build new generating capacity for export sales, to offer new energy-related services, to enter into strategic alliances and joint ventures and to create subsidiaries.
- There are presently no plans to move to full retail competition in the Province.
- Manitoba Hydro retail customers currently enjoy rates that are among the lowest in North America as a result of the Utility's predominantly hydroelectric generation and efficient resource management.

Natural Gas Distribution

- Manitoba Hydro distributes natural gas through its wholly owned subsidiary, Centra Gas. In accordance with the rate-setting methodology for natural gas, commodity rates are changed every quarter based on 12-month forward natural gas market prices.
  - The commodity cost of gas is a pass-through with no markup to customers.
  - Non-commodity costs, such as transportation and storage are also passed on.
- The PUB allows Centra Gas to target an annual profit of approximately \$3 million, which is fairly modest compared with Manitoba Hydro's consolidated earnings.

Watershed Storage Capacity

Manitoba Hydro draws water from five distinct watersheds: Nelson River, Winnipeg River, Saskatchewan River, Churchill River (including the Laurie River) and Burntwood River. This provides the Utility with some geographic diversification, especially during times of low hydrology. The main generation source is the Nelson River, which accounted for approximately 76% of power generated in F2017.

Source of Electrical Energy Generated and Imported

For the year ended March 31, 2017

Nelson River	**75.81%**
Billion kWh generated	**28.4**
Limestone	26.22%
Kettle	23.32%
Long Spruce	18.26%
Kelsey	5.61%
Jenpeg	2.39%
Winnipeg River	**11.04%**
Billion kWh generated	**4.1**
Seven Sisters	3.47%
Great Falls	2.66%
Pine Falls	1.65%
Pointe du Bois	0.74%
Slave Falls	1.29%
McArthur	1.23%

Saskatchewan River	**6.23%**
Billion kWh generated	**2.3**
Grand Rapids	6.23%
Laurie River	**0.14%**
Billion kWh generated	**0.1**
Laurie River #1	0.07%
Laurie River #2	0.07%
Burntwood River	**3.82%**
Billion kWh generated	**1.4**
Wuskwatim	3.82%

Thermal	**0.11%**
Billion kWh generated	**0**
Brandon	0.09%
Selkirk	0.02%

Purchases (excl. wind)	**0.24%**
Billion kWh imported	**0.1**
Wind	**2.61%**
Billion kWh	**1.0**

Source: Manitoba Hydro.

Favourable characteristics inherent in Manitoba Hydro's watersheds include the following:

- Cold temperatures reduce overall evaporation rates, as many of the reservoirs are frozen over for up to five months of the year.
- A significant portion of the watersheds consists of rock, which has lower seepage rates and higher runoff than predominantly soil-covered watersheds.
- Lake Winnipeg, Cedar Lake and Southern Indian Lake serve as large storage reservoirs. The Utility's water storage capacity is a competitive advantage in trading electricity (buying surplus U.S. power at low off-peak prices and selling its electricity during peak demand periods at higher prices).

In addition to its own generating stations in Manitoba, Manitoba Hydro purchases all electricity from two wind farms in southern Manitoba (St. Joseph Wind Farm and St. Leon Wind Farm). The installed capacity of these facilities is 258.5 MW. The Wuskwatim Generating Station is owned by the Wuskwatim Power Limited Partnership, in which Manitoba Hydro is the majority owner. Manitoba Hydro purchases all the electricity generated from the Wuskwatim Generating Station.

Generating Capacity

Manitoba Hydro's Generating Stations and Capabilities

For the year ended March 31, 2017

Power Station	Location	# of Units	Net Capacity (MW)
Hydroelectric			
Great Falls	Winnipeg River	6	129
Seven Sisters	Winnipeg River	6	165
Pine Falls	Winnipeg River	6	83
McArthur Falls	Winnipeg River	8	55
Pointe du Bois	Winnipeg River	16	75
Slave Falls	Winnipeg River	8	68
Grand Rapids	Saskatchewan River	4	479
Kelsey	Nelson River	7	295
Kettle	Nelson River	12	1,220
Jenpeg	Nelson River	6	91
Long Spruce	Nelson River	10	980
Limestone	Nelson River	10	1,350
Laurie River (2)	Laurie River	3	10
Wuskwatim	Burntwood River	3	213
Total Hydroelectric Generation		**105**	**5,213**
Thermal			
Brandon (coal: 93 MW, gas: 234 MW)		3	331
Selkirk (gas)		2	125
Total Thermal Generation		**5**	**456**
Isolated Diesel Capabilities			
Brochet			3
Lac Brochet			2
Shamattawa			3
Tadoule Lake			2
Total Isolated Diesel Generation			**10**
Total Generation Capacity			**5,679**

Source: Manitoba Hydro.

The Manitoba Hydro-Electric Board 1

(CAD millions)	March 31				March 31		
	2017	2016	2015		2017	2016	2015
Assets				**Liabilities & Equity**			
Cash & equivalents	641	952	487	S.T. borrowings	0	0	0
Accounts receivable	385	372	427	Accounts payable	1,087	722	529
Inventories	108	117	99	Current portion L.T.D.	336	326	377
Prepaid expenses & other	128	43	54	Other current liab.	197	184	190
Total Current Assets	**1,262**	**1,484**	**1,067**	**Total Current Liab.**	**1,620**	**1,232**	**1,096**
Net fixed assets	19,757	17,208	15,222	Long-term debt (net sinking fund investments)	16,102	14,201	12,189
Goodwill & intangibles	400	301	290	Sinking fund investments	0	0	114
Investments & others	919	786	988	Other L.T. liab.	2,256	2,154	1,989
				Shareholders' equity	2,360	2,192	2,179
Total Assets	**22,338**	**19,779**	**17,567**	**Total Liab. & SE**	**22,338**	**19,779**	**17,567**

Balance Sheet & Liquidity & Capital Ratios	12 mos. ended Sept. 30	For the year ended March 31 1				
	2017	2017	2016	2015	2014	2013
Current ratio	0.90	0.78	1.20	0.97	0.70	0.48
Total debt in capital structure	87.5%	87.4%	86.9%	85.2%	78.9%	76.6%
Total debt in capital structure 2	84.9%	84.3%	83.0%	81.3%	79.4%	78.5%
Cash flow/Total debt	4.8%	5.3%	5.4%	5.3%	6.4%	6.1%
(Cash flow-dividends)/capex	0.27	0.30	0.35	0.38	0.50	0.57
Dividend payout ratio	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Coverage Ratios (times)						
EBIT gross interest coverage	1.00	0.97	0.98	1.13	0.96	0.89
EBITDA gross interest coverage	1.58	1.54	1.57	1.77	1.63	1.56
Fixed-charge coverage	1.00	0.97	0.98	1.13	0.96	0.89
Profitability Ratios						
Purchased power/electricty revenues	N/A	7.0%	6.5%	7.1%	8.6%	7.7%
Operating margin	30.9%	32.8%	31.9%	32.8%	30.9%	30.2%
Net margin	4.2%	3.4%	2.7%	7.2%	8.8%	4.9%
Return on equity 2	4.4%	2.4%	1.9%	5.0%	6.6%	3.5%

1 2015 to 2017 based on IFRS; 2013 and 2014 based on Canadian GAAP. 2 Adjusted for other comprehensive income.

Rating History

	Current	2017	2016	2015	2014	2013
Long-Term Obligations	A (high)	A (high)	A (high)	A (high)	A (high)	A (high)
Short-Term Obligations	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)

Note: These Obligations are based on the status of the Manitoba Hydro-Electric Board as a Crown agent of the Province of Manitoba and the unconditional guarantee provided by the Province on Manitoba Hydro's third-party debt and thus reflect the Province's debt ratings.

Previous Action

- Confirmed, July 4, 2017.

Related Research

- DBRS Confirms Province of Manitoba at A (high) and R-1 (middle), Stable Trends, July 4, 2017.
- *Manitoba, Province of: Rating Report*, July 12, 2017.

Short-Term Promissory Notes Programme

- $500 million.

Previous Report

- Manitoba Hydro-Electric Board, The: Rating Report, November 25, 2016.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on www.dbrs.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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