ONTARIO ENERGY BOARD

Oshawa PUC Networks Inc. (OPUCN)

2015-2019 Custom Incentive Regulation Rate Plan
Mid-Term Update

OPUCN REPLY

Introduction

1. In November, 2015 the Ontario Energy Board (OEB or Board) issued its decision (2015 Decision) on OPUCN's Custom Incentive Rate Plan (CIR Plan) Application for the test years 2015 through 2019 (CIR Application).[1] In its 2015 Decision the Board set OPUCN's rates for 2015, 2016 and 2017 on a final basis, and for 2018 and 2019 on an interim basis. In respect of 2018 and 2019 rates, the Board directed a mid-term review to allow for further 2018 and 2019 rate adjustments, if warranted, based on *"a limited number of 2016 actual and forecast updates"*.[2]

2. The 2015 Decision directed OPUCN to file an application for finalization of 2018 and 2019 rates through consideration of the following particular elements of OPUCN's 2018 and 2019 interim rates[3]:

   (a) Forecast of new customer connections (currently approved for 2018 and 2019 at 3%[4]) and consumption.

   (b) The amount and timing of capital expenditures resulting from:

      (i) The proposed MS9 substation.[5]

[1] EB-2014-0101, Decision and Order, November 12, 2015.
[2] 2015 Decision, page 9.
[3] 2015 Decision, pages 9-10.
[4] 2015 Decision, page 30.
[5] 2015 Decision, page 20.

(ii) "Regional planning"; i.e. the cost and schedule of the proposed Hydro One Enfield TS and associated OPUCN contributions and other related capital expenditures.[6]

(iii) Third party requests for relocation of OPUCN plant.[7]

(iv) New customer connections.[8]

(c) The OEB Cost of capital parameters from 2017.[9]

(d) Cost of power, and attendant changes to working capital allowance.[10]

3. Making the adjustments directed by the Board in its 2015 Decision, OPUCN's final rates for 2018 and 2019 would decrease relative to interim rates as follows[11]:

Year	Interim Base Revenue Requirement ($000s)	Updated Base Revenue Requirement ($000s)	Interim Residential Rate	Final Residential Rate
2018	$24,975	$23,741	$17.93 Fixed/Month $0.0078 per kWh	$17.35 Fixed/Month $0.0078 per kWh
2019	$26,406	$24,974	$21.55 Fixed/Month $0.0041 per kWh	$20.97 Fixed/Month $0.0041 per kWh

4. For a typical residential customer consuming 800 kWh/month the monthly bill impact of OPUCN's proposed rate adjustment would be a decrease, compared to interim rates, of $0.58 in 2018 and $0.58 in 2019.

Updated Load Forecast[12]

5. Interim rates for 2018 and 2019 were set in the 2015 Decision based on OPUCN's initial (as filed in the CIR Application) customer growth forecast of 3% for each of these years.

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[6] 2015 Decision, pages 20 and 23.
[7] 2015 Decision, page 9.
[8] 2015 Decision, page 9.
[9] 2015 Decision, pages 32-33.
[10] 2015 Decision, page 22.
[11] Exhibit A, page 4, Table 1.
[12] See generally Exhibit A, pages 11-15.

6. In the 2015 Decision the Board approved an annual 1.5% growth rate for 2015, 2016 and 2017 and OPUCN's initially proposed 3% growth rate for 2018 and 2019, and provided OPUCN an *"opportunity to update the forecast growth rate for 2018 and 2019 based on actual results to date at the mid-term review"*.[13]

7. Actual customer connection growth rates for 2015 and 2016 were 1.9%, and OPUCN's updated forecast for growth for 2017 is 1.5%.

8. Both the City of Oshawa and the Region of Durham continue to predict that growth rates will be higher than historical levels but also agree that the pace for such growth is likely to be more gradual than anticipated prior to the issuance of the most recent Region of Durham report.

9. Considering actual results to date, discussions had with representatives of the City of Oshawa, and the most updated report issued by the Region of Durham[14], OPUCN is proposing an updated customer growth forecast for each of 2018 and 2019 of 1.8%.

10. No party has taken issue with OPUCN's updated customer connections growth forecast of 1.8%.

11. In addition to updating its customer connection growth expectations, OPUCN has proposed to adjust its approach to forecasting demand and consumption for 2018 and 2019 to better reflect the observed trend of declining demand and consumption by its customers.[15] Parties have objected to this proposed approach adjustment as being beyond the scope of this mid-term update. Without addressing the clear evidence that the historical multiple regression analysis produces clearly opposite and counterintuitive results when compared to historical trends, parties' maintain that OPUCN should be required to continue to use a forecast approach which demonstrably simply no longer produces appropriate results.

12. As referenced at paragraph 31 of Exhibit A, and documented in Table 8 at page 14 of Exhibit A, the traditional multiple regression analysis approach to forecasting customer consumption has historically over-forecasted consumption for OPUCN, and thus resulted

[13] 2015 Decision, page 30.
[14] Exhibit A, page 12, paragraph 26.
[15] Exhibit A, page 13, paragraph 29.

in under-recovery by OPUCN. As explained in IRR 1-Staff-4, the traditional multiple regression analysis predicts an upward trend in consumption, whereas a historical linear analysis indicates a consistent downward trend in consumption.

13. OPUCN also noted in its application[16] the recent downward adjustment by the Board of its assumed average residential consumption from 800 kWh/month to 750 kWh/month, based on analysis which indicates a trend towards lower consumption by Ontario electricity consumers.

14. Beginning on page 7 of the Board's *Report of the Ontario Energy Board – Defining Ontario's Typical Electricity Customer (*Report*) [EB-2016-0153]*, issued on April 14, 2016, the OEB refers to an analysis and summarizes with the following statement [emphasis added]:

> *While isolating the exact contributions of different causes to the decline requires intensive analysis, <u>the conclusion is clear</u>: average residential consumption in Ontario is falling. In light of this trend, the OEB has determined it appropriate to update its standard definition of a typical customer's monthly consumption so that it provides consumers with a more accurate picture of how their bill will be impacted by rate changes and other new charges.*

15. OPUCN filed its complete load forecast model, which included the linear trend approach to forecast consumption, on October 27th, in response to Board Staff interrogatory 1-Staff 4, along with an explanation of the linear trend analysis adopted by OPUCN, and the basis for OPUCN's position that this model better reflects both actual and anticipated consumption.

16. In response to undertaking JT1.12 from the untranscribed teleconference provided for in Procedural Order No. 2 to allow for clarification of interrogatory responses, OPUCN provided the following table comparing the results of application of its derived linear trend model with those of the regression model used in derivation of OPUCN's CIR application load forecast:

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[16] Exhibit, page 14, paragraph 32.

Year	Purchased (GWh)[17]		Billed (GWh)[17]	
	Filed	Per Request	Filed	Per Request
2018	1,100	1,166	1,062	1,112
2019	1,098	1,171	1,060	1,117

17. This table illustrates that the historically used regression model predicts purchased power and billed power results that are 4% - 6% higher than the results predicted by analysis of historical actual (linear) trend. The revenue impact of this difference (i.e. the amount by which OPUCN believes it would under recover if rates are set based on the regression model) is approximately $419,338 and $383,970 in 2018 and 2019 respectively.

18. In proposing a linear trend in place of the historically used regression model OPUCN has considered that;

    (a) in the 2015 Decision the Board was reluctant to impose a load forecast that was higher than the most recent evidence (and thus reduced OPUCN's load forecast from its as filed CIR Plan forecast for 2015-2017, and directed a mid-term update for forecast growth for 2018 and 2019)[18];

    (b) in the 2015 Decision the Board directed that 2018 and 2019 growth forecasts be updated based on updated evidence of actual new customer connections and consumption[19]; and

    (c) there is a clear divergence of the regression analysis results for purchased and billed power from historically observed results (the latter clearly trends up while actuals clearly trend down);

19. OPUCN understood (as, apparently, does VECC[20]) that a customer consumption analysis was within scope for this mid-term update, and prepared its application accordingly.

20. OPUCN believes that its approach to updating new customer connections and consumption is appropriate and in keeping with the Board's intentions as reflected in the 2015 Decision. OPUCN requests approval of final 2018 and 2019 rates on this basis.

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[17] OPUCN has corrected a units error made in the initial filing of this table. The correct units are GWh, as noted here, rather than MWh as set out in the initial filing.
[18] 2015 Decision, page 30, 2nd paragraph.
[19] 2015 Decision, page 9.
[20] VECC Submissions, paragraphs 1 and 24, though VECC goes on to argue that OPUCN should have constrained itself to use of the historical regression load forecast model (see VECC Submissions, paragraphs 27-28).

21. VECC asserts in its Submission that it is not aware of any other OEB sanctioned use of a linear trend model to forecast purchased power. Be that as it may, it is clear to OPUCN, that the linear trend function which it utilized produce results that are directionally valid, based on historical analysis and the Board's own recent adjustment to average residential consumption assumptions, while the regression model previously used yields results that contradict actual observations. OPUCN has no alternative but to conclude that the regression analysis approach no longer works for its own forecasting and actual experience demands an alternative approach so that its forecasts better reflect its actual results.

22. VECC acknowledges in its submissions that use of the historical regression analysis may result in over forecasting of purchased power. VECC says, however, that[21];

(a) this is part of the risk which OPUCN accepted in opting for a CIR Plan; and

(b) defaulting to this approach (which VECC acknowledges may not be a good predictor of future power purchases) is an appropriate *"consequence"* for OPUCN not pre-filing its model, and thus precluding *"a more fulsome exploration of the forecast and possible alternatives"*.

23. In respect of VECC's "risk acceptance" assertion, that assertion ignores the very fact that the 2015 Decision specifically directs customer consumption analysis in updating 2018 and 2019 rates. That is, the Board specifically decided that OPUCN should not have to bear this risk in respect of the last two year period of its CIR Plan.

24. In respect of VECC's suggestion that OPUCN should be punished for not pre-filing its load forecast modelling, OPUCN did file its model when requested, fully co-operated in addressing questions in respect of that model in IRRs and again in technical conference undertaking responses, and obviously provided VECC with sufficient information to ground detailed closing submissions on the matter.

25. VECC also submits (as OPUCN understands it) that because its historical trend line includes realized CDM savings, and projects similar further savings in future in line with historical savings, adding additional CDM adjustments to 2018 and 2019 is "double counting" the impact of future CDM programs. OPUCN notes that its approach to

[21] VECC Submissions, paragraph 37.

accounting in its forecasts for CDM savings, as extensively detailed in response to undertakings JT1.1 and JT1.3, is no different in this application than in its previous rate applications, including in its 2015 CIR Application, and has been previously accepted by the Board.

26. OPUCN submits that it has been both transparent and true to the spirit and intent of the 2015 Decision in considering historical customer connections and consumption, and proposing updates to its interim 2018 and 2019 rates using the best information which it has available to it.

27. OPUCN further submits that it has fully engaged in, and co-operated in, the process for review of its CIR Plan mid-term update, as that process has been dictated by the Board, and should not be penalized if VECC or anyone else found that process to be less than they desired.

28. OEB Staff indicates that they do not support OPUCN's proposed loss factor reduction from 4.86% to 3.59%, on the basis that the 2015 Decision did not make provisions for this update, and OPUCN has not explained the reasons for the reduction.[22] OPUCN notes that this load forecast adjustment was not objected to by any other parties, and that the adjustment favours ratepayers (i.e. lower forecast losses results in lower rates).

Capital Expenditures for Third Party Relocations

29. The 2015 Decision directed that OPUCN's mid-term update would consider the amount and timing of capital expenditures resulting from third party requests for relocation of OPUCN plant and new customer connections, and adjust 2018 and 2019 rates as warranted.[23]

30. The cumulative spend on third party relocations is expected to be approximately $2.4 million below plan at the end of 2017.[24] The cumulative spend on new customer connections is, for the same period, $0.7 million over plan.

[22] OEB Staff Submissions, page 10.
[23] 2015 Decision, page 9.
[24] Exhibit A, paragraphs 41 and 43.

31. Total "system access" capital underspend for the 2015 through 2017 period is currently forecast at $1.6 million, and total capital underspend for the same period is forecast to be $0.884 million.[25]

32. Through the end of the CIR Plan period, and based on city and regional planning and the updated schedule for completion of infrastructure for the 407 ETR extension, OPUCN does not anticipate any change from previously approved to the total planned capital spend for third-party requested plant relocations through the end of its CIR Plan in 2019.[26]

33. OPUCN notes that the 2015 Decision "ring fenced" (through a variance account) only OPUCNs system renewal expenditures[27], and OPUCN's spending to date on system renewal has been essentially as approved.[28]

34. For other asset categories, OPUCN accepted the spending risk for the period 2015 through 2017, and the OEB acknowledged through direction for this mid-term update that the unpredictable and unprecedented level of customer growth activity attendant on the 407 extension through Oshawa warranted a review of these categories of expenditures through this mid-term review, and 2018 and 2019 adjustment to rates as warranted.

35. OPUCN has considered, and agrees with, the submissions of OEB Staff[29] and CCC[30] that OPUCN's previously approved (on an interim basis) forecast for capital expenditures for 2018 and 2019 be retained unchanged. OPUCN believes this is the appropriate approach to offset the underspend occurring through 2017 with the overspend forecast for 2018 and 2019. This approach is consistent with the CIR policy that OPUCN is generally expected to manage its affairs within its CIR Plan. Differences in revenue requirement resulting from timing adjustments are immaterial.

36. OEB Staff has also proposed that the Board establish a variance account to capture impacts of increased work during the balance of the CIR Plan term.[31] OPUCN believes

[25] IRR 1-Staff-3.
[26] Exhibit A, paragraph 41.
[27] 2015 Decision, page 12.
[28] IRR 1-Staff-3.
[29] OEB Staff Submissions, page 5, 2nd full paragraph.
[30] CCC Submissions, page 3, last paragraph.
[31] OEB Staff Submissions, page 5, 2nd full paragraph.

that its overall CIR Plan rates already capture all forecast work, and a variance account is thus not required.

37. In respect of VECC's proposal to shift the 2015-2017 relocation project underspend to 2018 and 2019 in place of the currently approved interim budgets[32], and SEC's proposal to reduce the 2018 and 2019 relocation project budgets by[33] 50%, OPUCN reiterates its evidence that it does expect to spend the entire relocation project budget over the full CIR Plan term.

38. SEC, CCC and VECC have argued that OPUCN's opening 2018 rate base should be adjusted (reduced) to account for the $2.4 third party relocations underspend.

39. This would be inappropriate if only on the basis that it selectively ignores the fact that OPUCN has overspent on third-party connections (relative to plan) in the amount of $0.7 million and, as acknowledged by OEB Staff and VECC[34], overall capital expenditures for 2015 through 2017 are forecast to be only $0.884 million below plan.

40. Further, OPUCN's actual cost of power during the 2015 through 2017 period was significantly higher than forecast, and a new underground project unforeseen at the time of its CIR Plan application (considered in the current process and not objected to by OEB Staff[35]) is now forecast to cost $1.9 million[36].

41. In any event, OPUCN does not understand the 2015 Decision to contemplate a CIR Plan term rate base adjustment.

42. In the 2015 Decision the Board directed OPUCN to file this application for adjustment and finalization of its 2018 and 2019 revenue requirement and rates[37]. OPUCN understands this direction to limit 2018 and 2019 updates to the revenue requirement impact of capital expenditures in the test years (which is OPUCN's understanding of how capital pass-

[32] VECC Submissions, paragraph 15.
[33] SEC Submissions, page 3.
[34] OEB Staff Submissions, page 4, first paragraph; VECC Submissions, paragraph 8.
[35] OEB Staff Submissions, page 5 bottom – page 6 top.
[36] Interrogatory Response 1-Staff-3.
[37] 2015 Decision, page 42, ordering paragraph 5.

through expenditures have been dealt with in other rate plans, such as Union Gas Limited's and Enbridge Gas Distribution's current multi-year rate plans).

43. VECC has argued that OPUCN's opening 2018 rate base should be adjusted based on actual 2015-17 capital expenditures (in VECC's submissions, the adjustment would be on account of the net underspend of $0.884 million[38]). VECC asserts that the Board's direction that this mid-term update include comparison of actual to forecast capital expenditures requires a conclusion that this is what the Board intended.[39]

44. OPUCN disagrees with this argument. As also cited by VECC[40], the 2015 Decision indicated:

> *The comparisons should provide information, including on financial performance, sufficient for the OEB to determine whether rate adjustments are warranted.*

45. OPUCN interprets this passage to indicate the Board's intentions that actual 2015 through 2017 financial performance would be a factor in considering whether the 2018 and 2019 updates contemplated required prospective rate adjustments in those years.

46. Accordingly, OPUCN is not expecting to adjust its rate base until following completion of its CIR Plan. Rather, OPUCN has recast rates for 2018 and 2019 based on the revenue requirement impacts of the limited 2018 and 2019 updates contemplated in the 2015 Decision.

Capital Expenditures for Regional Planning

47. The 2015 Decision directed that OPUCN's mid-term update would consider, and the Board would adjust 2018 and 2019 rates as warranted, for the amount and timing of capital expenditures resulting from:

(a) The proposed MS9 substation.[41]

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[38] VECC Submissions, paragraph 8.
[39] VECC Submissions, paragraph 9.
[40] VECC Submissions, paragraph 8.
[41] 2015 Decision, page 20.

(b) "Regional planning"; i.e. the cost and schedule of the proposed Hydro One Enfield TS and associated OPUCN contributions and other related capital expenditures.[42]

48. OPUCN's interim 2018 and 2019 rates include $28 million in regional planning associated costs. OPUCN proposes to update its 2018 and 2019 rates to take into account;

(a) a reduction in regional planning costs by $3 million to $25 million; and

(b) deferral of the expected in service date for Enfield TS and related assets to 2019.

49. The chronological development of cost forecasts for MS9, Enfield TS and related connection infrastructure was summarized in Exhibit JT1.4, from which the following table is taken:

Asset Description	Original DSP	Decision on Custom IR	Mid Term Application
Enfield TS Contributions	$6,500	$13,500	$4,000
MS9 Substation	$7,000	$7,000	$7,000
MS9 Overhead Feeders	2,000	$7,500	$7,500
Overhead Feeder Enfield TS Egress and Load Transfer	Nil	Nil	$6,500
Total	**$15,500**	**$28,000**	**$25,000**

50. OPUCN's forecasts of costs for the MS9 substation and related overhead feeders is unchanged from the forecasts approved in the 2015 Decision - $7 million and $7.5 million, respectively - with an unchanged expected in service-date of 2018. No parties have taken issue with these costs.

51. OPUCN has now executed a Connection Cost Recovery Agreement (CCRA) with Hydro One[43] which finalizes (subject to post-construction true up) the required capital contribution by OPUCN for the net costs of Enfield TS. OPUCN's capital contribution has been reduced from the $13.5 million estimated at the time of the 2015 Decision to $4

[42] 2015 Decision, pages 20 and 23.
[43] Filed as Exhibit A, Attachment 1.

million, and the timing for Enfield TS has been delayed by one year. OPUCN has updated its proposed final 2018 and 2019 rates to reflect these changes.

52. As the regional planning process has been completed, overhead feeders for Enfield TS egress and load transfer have now been identified, as detailed in undertaking JT.5. New feeder circuits are required in order to connect Enfield TS to OPUCN's distribution system, and pole rebuilds are required to connect distribution system infrastructure and permanently relive over-capacity load constraints from Wilson TS and Thornton TS, and transfer load to Enfield TS. These facilities which were not included in the regional planning information available at the time of the 2015 Decision, are forecast to cost $6.5 million, consisting of $1.5 million is for station egress, and $5 million is for a 44 kV feeder.

53. No party has questioned the $1.5 million forecast for station egress.

54. OEB Staff have compared OPUCN's forecast of the costs for the 44 kV feeder to costs recently proposed by Hydro One for what OEB Staff assumes to be comparable work, and submits that OPUCN's costs are too high. Staff recommends reducing OPUCN's costs by 50%.

55. There is no evidence on the record regarding Hydro One's forecast costs. OPUCN is not aware that any of the costs used by OEB Staff for comparison purposes have been reviewed and approved, and cannot opine on whether the comparison is like for like. The scope of the subject Hydro One projects may differ significantly from that of OPUCN's 44 kV project.

56. OPUCN's understanding is that Hydro One builds express lines with longer spans and shorter poles (one voltage circuit), and generally is able to build on land along its pre-existing right of way.

57. In contrast, OPUCN's project will have taller poles with dual voltage circuits (44 kV and 13.8 kV) and shorter spans for dip/riser poles to service existing and new developments.

58. OPUCN poles are normally built within city/regional roadways and thus subject to city/region approval, traffic control, and night work required for busier intersections and commercial areas. OPUCN's forecast also includes costs for new switches to connect

Enfield TS feeders to the existing distribution system in order to implement a permanent load transfer.

59. OPUCN believes that its cost for required new feeder work for Enfield TS connection and related load transfer has been appropriately forecast, in the same manner as all of the work which the Board reviewed and approved as part of consideration of OPUCN's comprehensive Distribution System Plan during the 2015 Decision proceeding.

60. OPUCN notes that VECC has proposed, in light of what it views as a justified scope change for OPUCN's regional planning related expenditures, that OPUCN's revised regional planning related cost forecast be accepted, and that a variance account for revenue requirement impacts of regional planning expenditure variances be approved.

61. OPUCN accepts VECC's proposal as reasonable and endorses this approach.

Cost of Capital

62. As directed in the 2015 Decision OPUCN has updated its proposed 2018 and 2019 rates based on the Board's approved 2017 cost of capital parameters.

63. OEB Staff has recommended that OPUCN update its rate proposal to incorporate the Board's now approved 2018 cost of capital parameters. OPUCN plans to incorporate the Board's current cost of capital parameters in development of its draft rate order for approval at the conclusion of this process.

64. OPUCN notes that no party took issue with OPUCN's updated working capital allowance (other than VECC's submission that OPUCN's working capital allowance should ultimately take into account the balance of VECC's submissions).

Cost of Power and Attendant Working Capital Allowance Changes

65. OPUCN explained in its application that it updated its forecast cost of power based on the OEB's *Regulated Price Plan Report – April 20, 2017*, and then reduced the resulting rates by 25% to reflect the Ontario Government's announced Fair Hydro Plan.[44]

66. OPUCN indicated that it was seeking the Board's direction on whether to include in its cost of power related working capital adjustment the forecast impact of the Fair Hydro Plan.

67. Only OEB Staff made submissions on OPUCN's cost of power forecast for 2018 and 2019. Staff submitted that OPUCN should recalculate its cost of power using the most up to date information currently available.

68. In interrogatory response 1-Staff-5, OPUCN recalculated the cost of power using the latest RPP prices from the Board's June 22, 2017 *Regulated Price Plan Prices and the Global Adjustment Modifier for the Period July 1, 2017 to April 30, 2018* report. In its IRR OPUCN noted that applying these latest RPP prices resulted in an increase in the commodity cost and decrease in the global adjustment with a net reduction of approximately $3.5 million and $2.9 million for 2018 and 2019, respectively.

69. Upon further review, OPUCN notes that it initially applied the 25% Fair Hydro Plan reduction to all of its customers, rather than adjusting its price forecasts only for those customers now determined to be eligible in accord with the Board's most recent report. Correcting for this previously overbroad application of the Fair Hydro Plan results in an increase the cost of power (relative to that initially filed herein) by approximately $12.3 million in each of 2018 and 2019.[45]

Additional Relief Sought

70. In this application OPUCN has also requested;

(a) a rate rider to effect disposition of OPUCN's Group 1 Deferral and Variance Accounts (DVAs); and

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[44] Exhibit A, pages 19-20.
[45] IRR 1-Staff-5.

(b) an adjustment to implement approved Retail Transmission Service and Connection costs.

71. Only OEB Staff made submissions on these two topics.

72. In respect of OPUCN's proposal to clear its Group 1 DVAs, Staff noted that the balances exceeded the Board's threshold for disposition, and are appropriately cleared.

73. Staff also submitted that OPUCN should;

(a) update the balances to be cleared to include Account 1551 (a credit balance of $36,292) which OPUCN missed in its initial calculations; and

(b) add 2017 interest in accord with the OEB's prescribed applicable interest rate.

74. OPUCN agrees with both of these submissions and proposes to implement these adjustments through its draft rate order.

75. No objection was taken to OPUCN's proposal for an adjustment to implement approved Retail Transmission Service and Connection costs.

CIR Plan Annual Report

76. In its 2015 Decision the OEB also directed that OPUCN report annually on the metrics which it proposed for its CIR Plan[46];

(a) OPUCN's OEB scorecard;

(b) OPUCN"s OEB service quality levels (which OPUCN undertook to maintain at 2014 levels); and

(c) OPUCN's outage reductions achieved as a result of its program to replace porcelain insulators and reduce foreign interference (animal contact).

77. Included in OPUCN's Application (filed as Exhibit B) was OPUCN's first CIR Plan annual report.

78. No party has taken any issue with the form or content of this report.

[46] 2015 Decision, page 11.

79. OPUCN will file its next CIR Plan annual report by April 30th, 2018.

ALL OF WHICH IS RESPECTFULLY SUBMITTED by:

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November 30, 2017