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March 25, 2014

RESS, COURIER AND EMAIL

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Hydro One Inc. EB-2013-0196
Norfolk Power Inc. EB-2013-0187
Hydro One Networks Inc. EB-2013-0198

We are counsel to Essex Powerlines Corporation, Bluewater Power Distribution Corporation, and Niagara-on-the Lake Hydro Inc. (collectively "EBN"). Pursuant to Procedural Order No. 9 dated February 18, 2014, we attach the Interrogatory Responses of EBN to Board Staff, Hydro One Networks Inc., and Norfolk Power Inc., in respect of the BDR Report.

Yours truly,

AIRD & BERLIS LLP

Dennis M. O'Leary

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cc Applicants and Intervenors

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EB-2013-0196
EB-2013-0187
EB-2013-0198

ONTARIO ENERGY BOARD

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Hydro One Inc. for leave to purchase all of the issued and outstanding shares of Norfolk Power Inc. under section 86(2)(b) of the Ontario Energy Board Act, 1998.

AND IN THE MATTER OF an application by Norfolk Power Distribution Inc. for leave to dispose of its distribution system to Hydro One Networks Inc. under 86(1)(a) of the Ontario Energy Board Act, 1998.

AND IN THE MATTER OF an application by Hydro One Networks Inc. seeking to include a rate rider in the 2013 Ontario Energy Board approved rate schedule of Norfolk Power Distribution Inc. to give effect to a 1% reduction relative to 2012 base electricity delivery rates (exclusive of rate riders) under section 78 of the Ontario Energy Board Act, 1998.

INTERROGATORY RESPONSES OF ESSEX POWERLINES CORPORATION BLUEWATER POWER DISTRIBUTION CORPORATION, and NIAGARA-ON-THE-LAKE HYDRO INC. (“EBN”) TO BOARD STAFF, HYDRO ONE NETWORKS INC., and AND NORFOLK POWER INC. IN RESPECT OF THE BDR REPORT

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Lawyers for EBN

BOARD STAFF INTERROGATORY #1

References:

(a) Evidence of Paula Zarnett, BDR on behalf of EBN, Page 13

> BDR therefore concludes that the Applicants have not shown that any significant reductions in costs related to field operations. The planned reductions in capital work have not been shown to be prudent, and may be the source of harm to customers.

(b) Hydro One's Responses to Interrogatories dated February 10, 2014, Exhibit I/Tab 2/Schedule 2/page 2

> With the elimination of an artificial electrical border between contiguous distributors, operational efficiencies arise in various areas, such as the ability to: rationalize local space needs through the elimination or repurposing of duplicate facilities like service centres; to more efficiently schedule operating and maintenance work and dispatch crews over a larger service area; and to more efficiently utilize work equipment (e.g., trucks and other tools), leading to lower capital replacement needs over time. Additionally, the elimination of the electrical border allows for more rational and efficient planning and development of the distribution system. All of the above provide the potential to result in operating and capital savings, both immediate and over time, which would provide long term benefits to ratepayers relative to the status quo.

INTERROGATORIES

1.1 Please indicate whether in reaching the above referenced conclusion [reference (a) above], BDR considered the information provided by HONI [reference (b) above]. If so, please provide details including whether BDR disagrees with HONI's assertion that the elimination of electrical borders between contiguous distributors will potentially result in operating and capital savings.

1.2 Board staff interprets BDR's conclusion [reference (a) above] to mean that the transaction will result in reductions in costs related to field operations, but such reductions are not significant in BDR's view. Please confirm whether Board staff's interpretation is correct. If confirmed, please provide BDR's estimate of the reductions. If not confirmed, please provide an explanation.

1.3 Please confirm whether it is BDR's position that HONI's planned capital expenditure reduction is not prudent. If so, please provide evidence supporting this position.

RESPONSES

1.1 BDR noted the referenced statement, but did not consider that it provided any information as to whether specific and identifiable savings would result from the elimination of the electrical border between the particular distributors involved in the proposed transaction--HONI and NPDI.

BDR does not disagree with HONI's statement that there is *potential* (i.e. that it is *possible*) to gain operational savings from the elimination of electrical borders between contiguous distributors *in general*. BDR's conclusion is that HONI has not provided support for its ability to achieve savings in this specific transaction.

1.2 BDR's estimate of changes in costs of field operations is based on the evidence filed by the Applicants.

The Applicants have provided information as to the change in costs resulting from two specific planned operational changes. The first is the reduction of field staff assigned to provide service in the NPDI service territory from 15 to 13, which BDR has understood as the result of the opportunity the Applicants perceive, "to more efficiently schedule operating and maintenance work and dispatch crews over a larger service area" as quoted above. However, the staff reduction, when combined with HONI's higher compensations levels, has the effect of increasing the related cost from $1,094,683 to $1,157,149, an increase of $62,466, annually, according to the table in Exhibit I, Tab 5, Schedule 26, Page 2 of 2.

The other cost change specifically identified by the Applicants in evidence as the result of the proposed transaction is an avoided cost of $60,000 resulting from the move of HONI's Dundas Field Business Centre functions from the City of Hamilton to the Town of Simcoe, over a 3-year period, as detailed in Exhibit I Tab 1 Schedule 4 Page 1 of 1.

In BDR's view, HONI has not demonstrated that it has no other existing building that could be used to avoid third party rent, if this proposed acquisition were not to proceed. If HONI has no other such building, were the transaction not to proceed, HONI could rent space from NPDI, thus benefitting NPDI's customers through the rent paid without harm to HONI's customers, relative to the cost of renting accommodation elsewhere.

If one does not accept the savings of $60,000 from the move of the Dundas Field Business Centre functions, according to the Applicants' evidence the net change in costs of field operations would be an increase of $62,466. If one does accept the savings of $60,000 from the move of the Dundas Field Business Centre functions, the net change in the cost of field operations would be an increase of $2,466.

It is BDR's conclusion based on this evidence, that costs related to field operations will be higher as a result of the proposed transaction.

1.3 In EB-2011-0272, Exhibit 2, Tab 3, Schedule 3, filed August 26, 2011, NPDI presented a detailed capital expenditure plan for the years 2012 through 2014, which, according to its evidence at that time, was derived from an Asset Management Plan which was also filed as part of its cost of service application. In explaining the Plan, NPDI pointed out that some of its asset base was 60 years old. The Board accepted the Settlement Agreement reflecting the review made by the parties, which provided for reduction of the amount of $4.6 million in capital expenditures applied for in the test year to $4.4 million (about 5%) as computed under CGAAP, or about $3.8 million under MIFRS. The levels of capital expenditure planned by NPDI at that time for 2013 and 2014 were similar to those for the test year.

It is therefore BDR's view that a capital expenditure level of approximately $3.8 million to $4.4 million (depending on the accounting standard used) is the level that was most recently tested and accepted through the regulatory process.

HONI's proposed alternative capital expenditure scenarios were presented in this proceeding as Exhibit I, Tab 2, Schedule 2, page 7 of 8 in a table that shows 3 scenarios. No explanation has been provided as to the engineering assumptions underlying each scenario, or the estimated probability of occurrence of each. Since it is not clear what accounting standard is assumed in the table, BDR has assumed that a scenario somewhere in the range bounded by HONI's low scenario (about $3.7 million per year under NPDI management) and the medium scenario (about $4.6 million per year under NPDI management) would represent continuation of the asset management planning approach taken by NPDI in its cost of service application.

As presented in the table, HONI is planning that the capital expenditures in the NPDI service territory be reduced from those levels to $2.3 million (low scenario) or $2.9 million (medium scenario) in 2015, a reduction of about a third from the NPDI levels, with a gradual further reduction thereafter. As discussed in the BDR report, HONI has not clarified how much, if any, of the reductions it believes can be achieved through efficiencies in execution of the capital plan, leaving the concern that the reductions are intended to be achieved by the cancellation or postponement of projects that were considered prudent at the time of the cost of service application It should be noted that HONI was asked a number of interrogatories for the details of their capital expenditure plan for NPDI, and it did not provide any details.

In addition, it is noted that at Exhibit I, Tab 5, Schedule 20, Page 1 of 2, the Applicants say "Other transaction costs, such as the costs to bring equipment up to Hydro One standards, will be recovered through revenues from former NPDI customers". Although not specified, BDR has understood the related costs to be capital expenditures, and to be costs that would not have been part of the capital expenditure plan filed by NPDI in its cost of service application. These therefore represent further amounts that would need to be included in the plan for capital expenditures under ownership by HONI. Assuming that HONI's $2.3 million (low scenario) or $2.9 million (medium scenario) for 2015 include these costs, there is a further increase in the gap between HONI's proposed spending on other capital works within NPDI and the plan that was part of NPDI's rate application.

No evidence has been provided to the effect that HONI's plan to reduce capital expenditures by about one-third from the most recent approved levels, not only for the immediate future but for at least a decade, is supported by a new Asset Management Plan for NPDI or other engineering reviews of the service territory's sustainment requirements. This is the basis of the concern expressed by BDR in its report.

BOARD STAFF INTERROGATORY #2

Reference: Evidence of Paula Zarnett on behalf of EBN, Page 14

> "…BDR has drawn the conclusion that the Applicants' savings estimate is overstated, and that such benefits which may be achievable would not be achieved immediately. Furthermore, if HONI is in fact able to eliminate 30 positions within NPDI, while maintaining its own level of FTEs at levels determined for its legacy service territory and customers, it suggests that HONI's resources are above the efficient levels to serve the legacy service territory and customers.

INTERROGATORIES

2.1 Please provide the percentage by which BDR believes the Applicants' projected savings are overstated along with supporting information.

2.2 Please identify any savings projected by HONI that in BDR's view are not achievable and indicate why they are not achievable.

2.3 Is it BDR's position that HONI's plan to eliminate 30 of the 46 positions currently required to operate NPDI is not achievable? If so, please provide specific information supporting BDR's position.

2.4 Is it BDR's view that HONI cannot achieve any economies of scale? If so, please explain the basis for this view.

RESPONSES

2.1 For the reasons set out in the BDR report, BDR is of the view that when all factors are taken into consideration, the evidence does not support making the conclusion that the transaction will result in net savings.

2.2 Please see Section 2.3.2 of the BDR report, which itemizes in a table the key administrative and customer service functions and why it is questionable that savings projected by HONI will be achieved.

2.3 BDR's concern with respect to HONI's proposed elimination of 30 positions is set out at page 13 of the report: "HONI has provided no information to support that 19,000 customers, 779 km of line, and one LDC organizational structure with accounts, a licence, rates, etc., is within the relevant range in which its cost of management, professional and "indirect" services are truly fixed in the sense that no incremental effort is required to add their activities to the resources of HONI. If it is assumed that the resource levels included in HONI's recently filed Custom IR application are efficient levels to carry out the functions of HONI as it now exists, some, and probably most, of the positions now within NPDI would probably continue to be needed." In addition, because of the higher compensation levels within HONI, which would then apply to all of the former NPDI positions, there would be a cost increase to offset the reductions, if any, which may be achieved.

2.4 Please see the answers to 2.2 and 2.3 above.

BOARD STAFF INTERROGATORY #3

Reference: Evidence of Paula Zarnett on behalf of EBN, Pages 4-5

> The Applicants have not provided any information to show that the excess premiums involved in this transaction, aggregated with the premiums from other transactions in the works or planned, will not affect the capacity of Hydro One to borrow, or increase its costs to do so.

INTERROGATORY

3.1 Is it BDR's position that the proposed transaction price will affect the financial viability of HONI or its parent company? If so, please provide evidence supporting this position.

RESPONSE

3.1 BDR's position is that the aggregate transaction price of this transaction and some number of future transactions carried out on the same basis (excessive premium) may affect the cost of debt for HONI or its parent, and thus be a source of potential harm to consumers. If many similar transactions occur and result in an increase in the cost of debt, or in constraints on borrowing needed to fund the replacement of aging transmission and distribution infrastructure, all of the transactions including this transaction must be considered as contributing to this result. It is not BDR's position that this transaction alone is of sufficient magnitude to affect financing capability or cost for HONI or its parent.

HYDRO ONE NETWORKS INC. INTERROGATORY #1

References:

(i) Evidence of Paula Zarnett on behalf of EBN, page 13

"BDR therefore concludes that the Applicants have not shown that any significant reductions in costs related to field operations. The planned reductions in capital work have not been shown to be prudent, and may be the source of harm to customers."

(ii) Evidence of Paula Zarnett on behalf of EBN, page 19

"BDR is also concerned that service quality and reliability may be reduced as a result of lower capital spending on the distribution system, resulting in harm to the customers."

(iii) Other OEB Proceedings as follows:

EB-2013-0416:	Exhibit A, Tab 17, Schedule 7 –Exhibit D1, Tab 2, Schedule 1
EB-2012-0136:	Exhibit I, Tab 2, Schedule 1.11 Staff 12 Technical Conference Response VECC 5, EI
EB-2012-0031:	Exhibit A, Tab 13, Schedule 2, pages 31 and 96 Exhibit D1, Tab 4, Schedule 3
EB-2009-0096:	Exhibit D1, Tab 2, Schedule 1

(iv) Current Proceeding:

EB-2013-0187/0196/0198	Exhibit I, Tab 1, Schedule 5 Exhibit I, Tab 2, Schedule 3

INTERROGATORIES

(a) From an operating and maintenance perspective does BDR agree that NPDI's distribution system assets are of the same class and type as those that Hydro One Distribution currently owns and operates? If BDR cannot agree, please explain.

(b) How did BDR take into account the fact that the NPDI operating and maintenance cost estimates post-acquisition have been developed using the same methodology and approach that Hydro One Distribution uses for the development of operating and maintenance cost estimates for its overall system assets?

(c) If BDR was not aware of this fact (see References iii and iv above), how does this change BDR's conclusions reached in Reference (i) above?

RESPONSES

In respect of the documents identified by HONI in (iii) above, it should be noted that the first – EB-2013-0416 – specifically states that it excludes the impact of the acquisition of Norfolk (EB: 2013-0416 Stakeholder Consultation Notes, Exhibit: A-20-1, Appendix B, Page 9 of 19, and Exhibit A-20-1 Appendix E, Page 27 of 109.) BDR notes the applicants did not file any of the above documents in evidence in this proceeding. Even if they had been filed, there is nothing in the documents identified which prove that there will be any capital or O&M savings as a result of the HONI acquisition. Indeed, it should be noted that of the four proceedings identified – EB-2012-0136, EB-2012-0031 and EB-2009-0096 – all preceded this application and are therefore of questionable relevance. Finally, BDR notes the fact that where HONI may have a capital asset review process in place for its legacy system, this review process does not appear to have been used to develop an asset condition assessment or asset management plan of Norfolk's assets for this proceeding. Interrogatories were asked requesting that HONI produce any studies or calculations which justified its reduction in capital spending. No detailed analysis was provided.

(a) BDR presumes that NPDI's distribution system consists of the asset classes that are typical of an electricity distribution system, namely, lines, transformers, poles, etc., as does HONI's, some of which are of the same class and type. BDR, however, also presumes that the assets mix, manufacturer, age and configuration are not the same.

(b) BDR reviewed the references to exhibits filed in this proceeding with regard to development of operating and maintenance cost estimates. Exhibit I, Tab 1, Schedule 5 says: "By incorporating Norfolk Power into Hydro One's operating and maintenance program and asset management processes, Hydro One is confident it can maintain or exceed its current reliability performance." No mention is made of cost estimation. Tab 2 Schedule 3 apparently addresses HONI systems that will be applied to NPDI upon integration of the systems, but makes no mention of cost estimation for purposes of developing estimates of operating and maintenance cost synergies.

(c) BDR's conclusions are unchanged.

HYDRO ONE NETWORKS INC. INTERROGATORY #2

References:

(i) EB-2013-0416, Exhibit B2, Tab 1, Schedule 2

(ii) EB-2013-0187, Exhibit A, Tab 3, Schedule 1, Attachment 11, page 18

(iii) Evidence of Paula Zarnett on behalf of EBN, page 18

> "BDR concludes that the Applicants have not supported their claim that lower costs of debt are a certain benefit of the transaction, both because NPDI can and has already obtained cost effective debt capital from Infrastructure Ontario, and because there has been no commitment that Hydro One will refinance the higher-cost debt assumed in the transaction."

Preamble:

Hydro One Distribution in its 2015-2019 Cost of Service application filed evidence about its most recent debt issues (see reference (i) above). The cost of debt issued in 2012 and 2013 ranged from 2.78% to 4.59% for issuances varying in term from 5 to 50 years. These are standard corporate bonds which repay the entire principal amount at the end of their term.

NPDI's 2012 financial statements (per reference (ii) above) show that NPDI's debt consists of both bank loans ($13.1 million) and debentures from Infrastructure Ontario ($15.1 million). The cost of the debt associated with the bank loans consisted of two 25 year term swaps at 5.42% and 6.25 (plus BA stamping fees at 0.75%), and a 15-year term at 5.27% (plus BA stamping fee at 0.75%).

The rates provided in EBN's evidence available to municipal LDCs from Infrastructure Ontario are for serial and amortizing loans. Serial loans require repayments of an equal amount of principal semi-annually over the term of the loan, which halves the effective term of the loan. Similarly, amortizing loans repay principal over the term of the loan, which shortens the effective term. When comparing interest rates for loans it should be based on the same effective term. The periodic repayment of principal also increases refinancing risk as debt is repaid more frequently.

INTERROGATORIES

(a) Given that NPDI has both bank loan swaps and Infrastructure Ontario debentures, why did BDR omit debt obtained from bank loans in its comparison of debt interest rates to Hydro One?

(b) Does BDR agree that NPDI's rate base is projected to grow? If agreement cannot be provided, please provide a detailed rationale for this position.

(c) Please confirm how BDR has taken into account the difference in the effective term between serial bonds (Infrastructure Ontario) and standard corporate bonds (Hydro One) when comparing the interest rates of the two types of debt.

RESPONSES

(a) It was not BDR's intention to analyze or compare the existing loans or embedded cost of debt of HONI and NPDI. The intention of the comparison was to establish that NPDI, as a municipally-owned utility, has access to a source of low cost debt funding which will be lost with approval of the acquisition. The Applicants' statement, at Exhibit I Tab 2 Schedule 2 Page 5 of 8, suggests that the parameters of refinancing of NPDI's debt are uncertain.

> "Financing savings are expected to be achieved due to the acquisition, as a result of both a lower Hydro One cost of debt upon refinancing of some or all of the debt assumed in the transaction, and lower capital replacement needs over time.
>
> "These savings have not been quantified due to uncertainty related to the timing of refinancing, and of the size of the spread that will prevail when refinancing occurs."

However, the Applicants knew, or should have known, that at a minimum, the Infrastructure Ontario loans of NPDI would be required to be repaid early with some promptness, because, as indicated in the attached excerpt from the Infrastructure Ontario website and confirmed by BDR in a telephone conversation with Infrastructure Ontario staff, NPDI would no longer be eligible for Infrastructure Ontario loans under HONI ownership. For an electricity distributor to be eligible, it must be incorporated under Section 142 of the *Electricity Act* and 100% owned by one or more municipalities.

Attached is an excerpt from the loan agreement of Bluewater Power with Infrastructure Ontario, which has been provided since the corresponding agreement of Norfolk Power with Infrastructure Ontario is not available for us to review. Infrastructure Ontario confirmed that the key provisions in this excerpt are typical of the provisions in its loan agreements with municipal utilities.

The meaning of the excerpt is summarized as follows:

(i) The borrower, if an electricity distributor, must warrant at the commencement of the loan that it is 100% owned by one or more municipal corporations;

(ii) If the borrower ceases during the term of the agreement to be 100% owned by one or more municipal corporations, all of the outstanding amounts under the loan may become immediately due and payable to Infrastructure Ontario; and

(iii) In the case of early termination, there is a provision for Infrastructure Ontario to recover from the borrower the difference in present value between the interest that would have been payable under the loan agreement and the interest at current prevailing rates, to the end of the loan term, thus making the lender "whole" for any loss of value resulting from early termination of the loan.

It is not known whether a comparable "make whole" provision is part of NPDI's agreements for its bank loans; however comparable provisions are common practice in the financial industry.

The result is that even if HONI is able to provide financing to NPDI at a lower cost than what NPDI would have been able to obtain, at some point in the future (which is not necessarily the case and has not been specifically supported by the Applicants), net savings could not be realized until the effect of the "make whole" provisions of the existing loans have been offset, which would be many years in the future.

(b) The Board's 2012 Electricity Distribution Yearbook at Tab IS shows NPDI's 2012 depreciation and amortization expense as approximately $2.3 million. Since rate base will grow if capital expenditures exceed depreciation and amortization, NPDI's rate base can, BDR concludes, be projected to grow in all capital expenditure scenarios as projected by HONI, except the HONI low scenario (reference Exhibit I Tab 2 Schedule 2 Page 7 of 8.) BDR has no additional or independent data to support a conclusion on this issue.

(c) The document included in EBN's evidence which sets out the Infrastructure Ontario lending rates available to local distribution companies provides a different rate for serial and amortizing loans. This document does not set out the terms of the loans, nor is there evidence as to the type of Infrastructure Ontario loans which Norfolk has negotiated which are referenced in its financial statement. The concern raised relates to the general assertion by HONI that it will offer lower debt rates than Norfolk's existing debt rates. This is not borne out when the availability of Infrastructure Ontario rates are considered. It is noteworthy that there is no mention in the application materials to the Infrastructure Ontario debt rates, the terms of those loans, and no attempt is made by the applicants to explain why the lower Infrastructure Ontario rates do not represent a lower cost of debt to Norfolk. BDR views the loss of the Infrastructure Ontario financing as an issue which constitutes a potential harm and notes that the application materials neither identify this issue nor suggest how this harm will be mitigated.

Projects

Loans

Eligible Borrowers

Lending Rates

Loan Payment Calculator

Strategic Partnership Program

Loan Program Stats

FAQs - Loans

Contact Customer Relations

Buildings

Lands

Commercial Projects

Loan Application

(username and password required)

Click to Apply

Home > What We Do > Loans

Filed: 2014/03/25
EB-2013-0196 / 0187 / 0198
EBN IRR HONI 2 - Attachment
1 of 1

Loan Program - Eligible Borrowers

Infrastructure Ontario's Loan Program provides long-term financing to eligible public sector clients to help renew infrastructure and deliver value to customers and residents.

The following public sector organizations are eligible to apply for loans:

- **Aboriginal Health Access Centres**
- **Community Health & Social Service Hubs**
- **Hospices**
- **Housing Providers**
- **Local Services Boards**
- **Long-term Care Homes**
- **Municipal Corporations**
- **Municipalities**
- **Professional Arts Training**
- **Sports & Recreation Organizations**
- **Universities and Affiliated Colleges**

For more details on eligibility, please review the program guidelines located on each sector's webpage.

Resources

- Loan Program Flyer
- Loan Activity Page
- Client Profiles
- Glossary of Terms
- Other Funding Resources

FINANCING AGREEMENT

THIS AGREEMENT (the "Agreement"), made in duplicate, dated and effective as of the 20th day of September, 2010 (the "Effective Date")

BETWEEN:

ONTARIO INFRASTRUCTURE PROJECTS CORPORATION
(herein after referred to as "OIPC");

and

BLUEWATER POWER DISTRIBUTION CORPORATION
(an Ontario corporation created under the *Business Corporations Act* (Ontario) herein after referred to as the "Borrower")

2. Representations and Warranties

The Borrower represents and warrants to OIPC that:

(b) the Borrower has been duly incorporated pursuant to Section 142 of the *Electricity Act*, 1998 (Ontario) as amended, all of the shares of the Borrower are held by one or more municipal corporations and the Borrower is in the business of generating, transmitting, distributing, or retailing electricity and has the corporate power and capacity to:

13. Term, Termination and Default

(a) This Agreement shall terminate ten (10) Business Days following the date on which the last Obligations outstanding hereunder are paid in full or following the last payment made by the Borrower to OIPC as specified on the Debenture(s) and or general security agreement pursuant to this Agreement unless earlier terminated in accordance with paragraphs (b) or (c) below.

(b) OIPC may terminate its obligations under this Agreement on thirty (30) days prior notice in writing to the Borrower if in the reasonable opinion of OIPC the Borrower is in material default under this Agreement, other than for any cause enumerated in (c) below or if OIPC rejects a new Debenture Purchase Date pursuant to section 11(b).

(c) OIPC may terminate any or all of its obligations under this Agreement immediately, subject to paragraph (d) below,

(x) if the shares of the Borrower are no longer held exclusively by one or more municipal corporations as further described in paragraph 2(b) above.

(d) If OIPC elects to terminate its obligations under this Agreement pursuant to paragraph 13(c) hereof, it shall give notice in writing of such termination to the Borrower, specifying the reason for such termination. Upon delivery of such notice OIPC shall have no further obligation to make any Advances or to purchase any Debentures hereunder. In such notice OIPC may also declare all Obligations and Debentures outstanding hereunder to be immediately due and payable, whereupon such Obligations and Debentures shall become immediately due and payable pursuant to paragraph 11(f) in addition to any other rights or remedies that OIPC may have at law or in equity to enforce such Obligations and Debentures.

(f) If OIPC elects to terminate its obligations under this Agreement in accordance with paragraphs 13(b) or (c) above, OIPC, at its discretion, shall assess any losses that it may incur as a result of the early termination as follows: if on the date of termination the outstanding principal balance on the Debenture is less than the net present value of the Debenture, the Borrower shall pay the difference between these two amounts to OIPC. Net present value will be calculated based on the following formulae: For Bullet Debenture – [(principal) / (1+(r/2))^n] + [(interest payment /(r/2))*(1-(1/(1+(r/2))^n)] or for Serial Debenture – [(principal) / (1+(r/2))^n] + [(interest payment /(r/2))*(1-(1/(1+(r/2))^n)] for each remaining serial principal repayment or for Amortizing Debenture – [(loan payment /(r/2))*(1-1/(1+(r/2))^n)], where "r" is the prevailing lending rate less an appropriate basis point deduction for costs incurred and "n" is the number of semi-annual periods to maturity.

HYDRO ONE NETWORKS INC. INTERROGATORY #3

Reference:

Evidence of Paula Zarnett on behalf of EBN, page 19.

> "With regard to Service Quality, BDR has concluded that information from public sources provides a basis for concern that NPDI customers may experience a decline in levels of Service with HONI. This information has not countered by evidence from the Applicants [sic]. BDR is also concerned that service quality and reliability may be reduced as a result of lower capital spending on the distribution system, resulting in harm to the customers."

Preamble:

As shown in response to EBN Interrogatory 26 (Exhibit I, Tab 5, Schedule 26), Figure 1 filed February 10, 2014, Hydro One plans to retain 13 of 15 NPDI direct staff (almost 90%) and manage them as part of a larger consolidated service area, out of Hydro One's existing Simcoe Operations Centre. The Simcoe Operating Centre is located less than 2 km from the existing Norfolk Power Operating Centre.

INTERROGATORY

Did BDR consider the benefits of consolidated field operations, including retention of local knowledge, in a single location in making its conclusion regarding service levels? If yes, please explain how.

RESPONSE

BDR understands that retention of most of the current direct staffing level and local knowledge, operating from a base that is located for time-effective access to the Norfolk service territory, should enable the current rate of emergency response to NPDI to be continued, as long as:

(a) Overall staffing for the "consolidated service area" is not significantly reduced; and

(b) Capital programs continue at a level that will maintain or reduce the number of outage incidents on the system.

HONI's lower levels of SQIs related to reliability and emergency response, especially in its rural areas, raises concerns that the mean standard of performance in HONI will drive staffing and investment decisions for the "consolidated service area", thus reducing service quality over time. In addition, HONI's forecast of substantial reductions in capital spending as compared with the levels indicated by NPDI's Asset Management Plan filed for its 2012 cost of service raises concerns that replacement of aging assets will be deferred, to the detriment of service levels.

NORFOLK POWER INC. INTERROGATORY #1

Reference:

BDR Report, Appendix A, page 27.

Preamble:

Norfolk would like to understand BDR's understanding of and ability to comply with the obligations pursuant to Rule 13A of the Rules of Practice and procedure of the Ontario Energy Board.

INTERROGATORIES

Rule 13A.02 states that: An expert shall assist the Board impartially by giving evidence that is fair and objective.

a) Please confirm that Ms. Zarnett's report complies with Rule 13A.02 as stated above.

b) Please confirm the date that BDR was retained by EBN.

c) Please include details of the retainer including:

   (i) Specific instructions provided to Ms. Zarnett upon retainer; and

   (ii) Any revisions to these instructions throughout the production of the BDR report.

d) Please confirm whether Ms. Zarnett or Mr. McNeil have been involved with or are currently in the process of entering any other retainers with any of the utilities that are part of the EBN group.

e) Please provide copies of all prior drafts of Ms. Zarnett's report which was ultimately filed with the Board.

f) Please provide copies of all correspondence between BDR and any member of the EBN group in connection with the report Ms. Zarnett filed in this proceeding.

RESPONSES

a) Ms. Zarnett's report complies with Rule 13.A.02. The reference in Appendix A to the BDR report to Rule 13.A was intended to refer to all responsibilities imposed on an expert by the Rule, including Rule 13.A.02. Ms. Zarnett, having provided expert evidence in other proceedings, was aware of Rule 13A.02 and was again reminded of this Rule for the purposes of the BDR Report.

b) BDR was retained in early October 2013.

c) BDR's scope of work is set out on page 2 of the report as:

(i) Review evidence as to cost structures to determine whether they are likely to increase or decrease as a result of the intended transaction;

(ii) To comment on non-financial impacts, such as quality of service; and

(iii) To consider and comment on whether the purchase price is set at a level that would create a financial burden on the acquiring utility; and

(iv) To develop and present a possible scenario for estimation of the impacts of harmonization of rates, once the proposed rate freeze period expires.

All four of the foregoing items were discussed and agreed as the scope of work from the time BDR was retained; however a final decision to develop and include a possible rate impact scenario was made in the week prior to filing of the report.

d) Ms. Zarnett carried out an affiliate transfer pricing study on behalf of Bluewater Power. The study was filed with the Board in EB-2012-0107, as Exhibit 4, Tab 5, Schedule 1, Attachment 2, in October, 2012. Her responsibilities concluded following the filing of interrogatory responses in the spring of 2013. Neither Ms. Zarnett nor Mr. McNeil has ever been retained by any of the EBN utilities in any matter other than the Bluewater Power transfer pricing study and the current proceeding.

e) No. All earlier drafts were partial documents without conclusions and thereby do not represent the opinion of BDR. As such, we consider them irrelevant.

f) Attached are copies of the documents which were provided to Ms. Zarnett by members of the EBN group as a convenience to her in making her review. All of the documents are in the public domain:

(i) Excerpt from the Ontario Energy Board 2012 Yearbook of Electricity Distributors,

(ii) Excerpt from NPDI cost of service proceeding (EB-2011-0272), Exhibit 5, Tab 1, Schedule (page 6 of 6)**;**

(iii) Copy of Article published in The Windsor Star, February 20, 2014, headed “$12M offer takes town by surprise”**;**

(iv) Article from the Chicago Tribune, page 1, February 26, 2014, and Lending Rates: Local Distribution Companies, Ontario Infrastructure

g) All of the above items were attached to or referenced in the BDR report. In addition, members of the EBN group provided Ms. Zarnett with rate comparison computations and with a descriptive explanation of the measures SAIDI, SAIFI and CAIDI, neither of which was used by Ms. Zarnett.

Unitized Statistics and Service Quality Requirements For the year ended December 31, 2012	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.	Hydro Ottawa Limited	Innisfil Hydro Distribution Systems Limited	Kenora Hydro Electric Corporation Ltd.	Kingston Hydro Corporation
# of Customers per sq km of Service Area	527.12	1.88	280.38	51.58	232.00	836.72
# of Customers per km of Line	48.03	10.32	54.71	19.24	56.82	74.17
Average Power & Distribution Revenue less Cost of Power & Related Costs						
Per Customer Annually	$ 436.65	$ 1,032.86	$ 505.21	$ 601.57	$ 538.13	$ 433.35
Per Total kWh Purchased	$ 0.015	$ 0.050	$ 0.020	$ 0.038	$ 0.028	$ 0.016
Average Cost of Power & Related Costs						
Per Customer Annually	$ 2,543.28	$ 1,976.31	$ 2,293.56	$ 1,532.31	$ 1,716.08	$ 2,448.12
Per Total kWh Purchased	$ 0.089	$ 0.096	$ 0.090	$ 0.096	$ 0.089	$ 0.090
Avg Monthly kWh Consumed per Customer	2,375.22	1,719.03	2,115.06	1,324.64	1,613.88	2,267.43
Avg Peak (kW) per Customer	4.52	2.50	3.82	2.89	3.05	4.16
OM&A Per Customer	$ 144.24	$ 439.77	$ 234.64	$ 323.02	$ 372.53	$ 234.98
Net Income Per Customer	$ 114.05	$ 211.70	$ 86.88	$ 47.30	$ 56.83	$ 71.06
Net Fixed Assets per Customer	$ 2,114.53	$ 4,811.59	$ 1,987.47	$ 1,894.00	$ 1,535.29	$ 1,197.68
Service Quality Requirements						
Low Voltage Connections (OEB Min. Standard: 90%)	100.00	95.70	100.00	95.30	100.00	100.00
High Voltage Connections (OEB Min. Standard: 90%)	100.00	95.70	100.00	N/A	N/A	100.00
Telephone Accessibility (OEB Min. Standard: 65%)	84.00	83.40	82.50	74.60	98.80	64.70
Appointments Met (OEB Min. Standard: 90%)	98.20	98.60	97.40	64.30	100.00	100.00
Written Response to Enquiries (OEB Min. Standard: 80%)	100.00	99.80	100.00	100.00	100.00	97.10
Emergency Urban Response (OEB Min. Standard: 80%)	100.00	N/A	98.50	N/A	100.00	88.90
Emergency Rural Response (OEB Min. Standard: 80%)	N/A	81.40	N/A	100.00	N/A	N/A
Telephone Call Abandon Rate (OEB Standard: not exceed 10%)	1.00	1.30	1.80	6.80	5.90	4.00
Appointments Scheduling (OEB Min. Standard: 90%)	100.00	98.50	99.80	98.30	100.00	89.30
Rescheduling a Missed Appointment (OEB Standard: 100%)	100.00	97.60	100.00	N/A	N/A	N/A
Reconnection Performance Standard (OEB Min. Standard: 85%)	100.00	97.60	100.00	97.20	100.00	100.00
Service Reliability Indices						
SAIDI-Annual	0.76	11.29	1.64	3.09	0.73	1.88
SAIFI-Annual	1.27	3.68	1.81	1.68	1.46	1.19
CAIDI-Annual	0.60	3.07	0.90	1.84	0.50	1.59
Loss of Supply Adjusted Service Reliability Indices						
SAIDI-Annual	0.74	10.58	1.31	1.34	0.43	1.78
SAIFI-Annual	1.06	3.15	1.13	0.71	0.46	1.17
CAIDI-Annual	0.70	3.36	1.15	1.90	0.94	1.52

N/A - Denominator is zero.

Table 1.3 – Cost of Long-Term Debt

Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance	Principal	Term (Years)	Rate%	Year Applied to	Interest Cost
Bank Loan 758020T	TD Bank	No	September 20, 2007	1,957,000	25	6.17%	2008	120,747
Bank Loan 682491T	TD Bank	No	September 20, 2004	3,257,000	15	6.02%	2008	196,071
Bank Loan 682495T	TD Bank	No	September 20, 2004	9,971,000	25	7.00%	2008	697,970
Debenture	Infrastructure Ontario	No	December 3, 2007	1,958,514	25	5.01%	2008	98,122
Bank Loan 758020T	TD Bank	No	September 20, 2007	1,909,000	25	6.17%	2009	117,785
Bank Loan 682491T	TD Bank	No	September 20, 2004	3,040,000	15	6.02%	2009	183,008
Bank Loan 682495T	TD Bank	No	September 20, 2004	9,751,000	25	7.00%	2009	682,570
Debenture	Infrastructure Ontario	No	December 3, 2007	1,914,923	25	5.01%	2009	95,938
Bank Loan 758020T	TD Bank	No	September 20, 2007	1,859,000	25	6.17%	2010	114,700
Bank Loan 682491T	TD Bank	No	September 20, 2004	2,811,000	15	6.02%	2010	169,222
Bank Loan 682495T	TD Bank	No	September 20, 2004	9,516,000	25	7.00%	2010	666,120
Debenture	Infrastructure Ontario	No	December 3, 2007	1,869,121	25	5.01%	2010	93,643
Debenture 09-01-2010-2	Infrastructure Ontario	No	September 1, 2010	5,600,000	25	4.73%	2010	264,880
Debenture 09-01-2010-1	Infrastructure Ontario	No	September 1, 2010	2,400,000	15	3.72%	2010	89,280
Debenture 09-01-2010-2	Infrastructure Ontario	No	September 1, 2010	5,540,286	25	4.73%	2011	262,056
Debenture 09-01-2010-1	Infrastructure Ontario	No	September 1, 2010	2,299,839	15	3.72%	2011	85,554
Bank Loan 758020T	TD Bank	No	September 20, 2007	1,805,000	25	6.17%	2011	111,369
Bank Loan 682491T	TD Bank	No	September 20, 2004	2,568,000	15	6.02%	2011	154,594
Bank Loan 682495T	TD Bank	No	September 20, 2004	9,266,000	25	7.00%	2011	648,620
Debenture	Infrastructure Ontario	No	December 3, 2007	1,820,995	25	5.01%	2011	91,232
Debenture 09-01-2010-2	Infrastucture Ontario	No	September 1, 2010	5,416,589	25	4.73%	2012	256,205
Debenture 09-01-2010-1	Infrastucture Ontario	No	September 1, 2010	2,093,895	15	3.72%	2012	77,893
Bank Loan 758020T	TD Bank	No	September 20, 2007	1,734,000	25	6.17%	2012	106,988
Bank Loan 682491T	TD Bank	No	September 20, 2004	2,243,000	15	6.02%	2012	135,029
Bank Loan 682495T	TD Bank	No	September 20, 2004	8,929,000	25	7.00%	2012	625,030
Debenture	Infrastructure Ontario	No	December 3, 2007	1,770,428	25	5.01%	2012	88,698
New Debt	Infrastructure Ontario	No	June 30, 2012	6,000,000	25	4.39%	2012	263,400

2008 Total Long Term Debt	17,143,514	Total Interest Cost for 2008	1,112,910
		Weighted Debt Cost Rate for 2008	6.49%
2009 Total Long Term Debt	16,614,923	Total Interest Cost for 2009	1,079,301
		Weighted Debt Cost Rate for 2009	6.50%
2010 Total Long Term Debt	24,055,121	Total Interest Cost for 2010	1,397,845
		Weighted Debt Cost Rate for 2010	5.81%
2011 Total Long Term Debt	23,300,120	Total Interest Cost for 2011	1,353,423
		Weighted Debt Cost Rate for 2011	5.81%
2012 Total Long Term Debt	28,186,911	Total Interest Cost for 2012	1,553,242
		Weighted Debt Cost Rate for 2012	5.51%

A2 THURSDAY, FEBRUARY 20, 2014 · THE WINDSOR STAR

$12M offer takes town by surprise

Utility selloff called 'huge' decision

BRIAN CROSS
The Windsor Star

For a town that's financially hurting, Tuesday's $12 million offer for Amherstburg's 14-per-cent share of Essex Power "is putting a big steak in front of the guard dog," says Coun. Bart DiPasquale.

He and other councillors were surprised by the size of Chatham-based Entegrus offer, triple the book value for the town's shares.

The question now being asked around town is whether council should chomp down on that $12 million. Some residents are telling councillors the cash infusion would help solve the town's money problems — a debt load of at least $44 million and reserves that have been vacuumed dry to pay day-to-day expenses. But others view it as selling off a goose that lays annual golden eggs and is bound to keep rising in value.

"The majority (of residents) I've seen don't want it sold because it is probably the only thing that makes the town money," DiPasquale said Wednesday.

Coun. Bob Pillon said that up until Wednesday, what he heard from residents was, "don't do it." But some attitudes changed when they heard the dollar amount, much higher than earlier estimates between $3.9 million and $5.6 million.

"I said, if it's not between $10 million and $15 million, I wouldn't even consider it," said Pillon. "And there it is at 12, so I'm considering it. Anyone who wouldn't consider it is a fool."

The town's CAO Mike Phipps told The Star last week that selling the shares to Entegrus could be the financial "saviour," perhaps preventing a double-digit tax increase.


Bob Pillon


Bart DiPasquale

But Deputy Mayor Ron Sutherland says that despite the surprising size of the offer, he's maintaining his opposition. Selling off the shares "will make our financial problems worse," said Sutherland, who is running for mayor in the fall election.

"Twelve million sounds like a great deal," he said. But it would be a one-time infusion of cash at the expense of annual dividends that — if they were gone — would amount to two per cent of the tax base, he said.

While the information provided Tuesday was that Amherstburg received a $200,000 dividend in 2012, Sutherland said he's received information from Essex Power that the town has received an average of $300,000 annually since the company was created in 2000.

Officials from Essex Power weren't available Wednesday to confirm that figure.

Tecumseh Mayor Gary McNamara, who chairs the Essex Power board, said Amherstburg council is facing a "huge" decision. "Do I give up my yearly dividends for one time? Once you sell it, it's gone."

The utility is jointly owned by the towns of Amherstburg (14 per cent), Tecumseh (about 27 per cent), LaSalle (about 29 per cent) and Leamington (about 27 per cent).

"The company is continuing to grow, it creates value for the shareholders, it pays dividends on a yearly basis and when you look at $12 million, it's a one-shot deal," McNamara said.

He said if Amherstburg does decide to sell its shares, the other shareholder towns have first right of refusal, meaning they could decide to match the offer. Either an individual town could match it or they could decide to share the costs. In addition to the annual dividend, Tecumseh reaps other benefits from owning shares of the utility, including holding a note bearing four per cent interest and green municipal projects (such as rooftop solar projects at the arena) that bring in revenue, he said.

He said last year Essex Power paid out $1.6 million in dividends to its shareholders, most of it coming from the unregulated side of its business that doesn't involve providing electricity to its customers. This includes a company called Utilismart, which develops electricity market software for about 80 per cent of the utilities in the province.

The town has 60 days to decide and is awaiting an expert's report on the fair market value of its shares, expected in April, which will be followed by a public meeting. Mayor Wayne Hurst said he's reserving judgment until he sees the report. He said everyone following the issue was probably "taken aback" by the size of the Entegrus offer.

Filed: 2014/03/25
EB-2013-0196/0187/0198
EBN IRR Norfolk 1(f)
Attachment
4 of 5

Hydro One sells C$1.185 notes in two parts - term sheet

October 02, 2013 | Reuters

Oct 2 (Reuters) - Hydro One on Wednesday sold C$1.185 billion ($1.15 billion) of medium-term notes in two parts, according to a term sheet seen by Reuters.

The sale consisted of C$750 million in 2.780 percent notes due Oct. 9, 2018, which were priced at 99.995 to yield 2.781 percent, according to the term sheet.

The sale also included $435 million in 4.590 percent notes due Oct. 9, 2043, which were priced at 99.984 to yield 4.591 percent.

The joint lead managers on the sale were the investment dealer arms of Bank of Montreal, Canadian Imperial Bank of Commerce, and Royal Bank of Canada.
($1=C$1.03)

(Reporting by Caryn Trokie)

Lending Rates: Local Distribution Companies

Indicative Lending Rates as of 25/02/2014

Term	Construction	Serial	Amortizer
1 Month	1.79%	-	-
5 Year	-	2.18%	2.28%
10 Year	-	3.06%	3.16%
15 Year	-	3.56%	3.66%
20 Year	-	3.86%	3.96%
25 Year	-	4.06%	4.16%
30 Year	-	4.18%	4.28%

About our Lending Rates

Our online lending rates are updated frequently as we track the movement of our cost of borrowing in the capital markets.

Debentures - rates on debentures are fixed for the entire life of the loan once the debenture is purchased by Infrastructure Ontario.

Construction Loans - for construction loans, rates float throughout the term of the loan until they are replaced by a debenture. Construction loan requests over $75 million are subject to funding availability and interest rates may vary from those posted.

**These interest rates are the all-in cost for loans of the term and type selected

NORFOLK POWER INC. INTERROGATORY #2

Reference:

CV of Paula Zarnett filed February 26, 2013, page 3.

Preamble:

Norfolk would like to confirm the relevance of Ms. Zarnett's experience to the matter currently before the Board. As the named author of the Report, Ms. Zarnett indicates on page 4 of her CV that she has testified before regulators in the following matters:

Toronto Hydro-Electric System
Saint John Energy
ICG Utilities
Rogers Cable and Communication Inc.

Written testimony:

Greater Sudbury Hydro
Bluewater Power
Kingston Hydro
FortisOntario
EnWin Utilities
Ontario Power Authority
City of Summerside

INTERROGATORY

a) Please confirm that none of these matters contained or involved a MAAD application.

RESPONSE

a) None of the above-noted matters involved a MAAD application. However, Ms. Zarnett has extensive experience in matters involving mergers and acquisitions of LDCs and their affiliates, the analysis of business ownership options (hold, merge, sell) for shareholders, and the planning and costing of business projects.

Some examples, which were also set out in the Appendix to the BDR report (page 28), include:

- Provided a fairness opinion to the City of Guelph on a proposal for merger of Guelph Hydro with Horizon Utilities (included review of confidential detailed merger business plans prepared by Horizon Utilities and Guelph Hydro and comparative valuation of the two LDCs)

- Advised Edmundston Energy and the City of Edmundston (New Brunswick) in a multi-year negotiation that resulted in purchase by Edmundston Energy of distribution service territory containing 3,000 customers from New Brunswick Power (included extensive exchanges of data on relative costs, lost synergies to New Brunswick Power, and incremental costs and synergies for Edmundston Energy)

- Developed a business plan and financial analysis for Edmundston Energy reflecting acquisition of 3,000 customers from New Brunswick power

- Advised the Town of Markham in the merger of Markham Hydro with Hydro Vaughan to form PowerStream Inc, including review of a “data room” which in which each party provided to the other data to enable independent assessment of the probable benefits that would arise from the merger.

Ms. Zarnett was part of the BDR consulting team that assisted several northwestern Ontario LDCs, including Hydro One, in evaluating the potential for synergies that might result from consolidation.

Ms. Zarnett was also part of the consulting team that assisted Lindsay Hydro and six other municipal utilities, who were among the first to offer themselves for sale following the coming into force of the legislation allowing such transactions. The sale was conducted through a competitive auction process, and resulted in Hydro One Networks acquiring the utilities.

Earlier in her career, Ms. Zarnett was a manager at Toronto Hydro at the time of the merger of the 6 “Metro” utilities (1998), and participated in one of the special teams formed to examine operational synergies and create organization and staffing plans for the business units of the new Toronto Hydro.

NORFOLK POWER INC. INTERROGATORY #3

Reference:

BDR Report, Executive Summary, Introduction and Scope, page 2.

Preamble:

Norfolk would like specifics on what informs the review performed by BDR as described on page 2 of the BDR report where it states that EBN requested it to:

- Review evidence as to cost structures to determine whether they are likely to increase or decrease as a result of the intended transaction;
- To comment on non-financial impacts, such as quality of service; and
- To consider and comment on whether the purchase price is set at a level that would create a financial burden on the acquiring utility; and
- To develop and present a possible scenario for estimation of the impacts of harmonization of rates, once the proposed rate freeze period expires.

INTERROGATORIES

a) Please provide all notes and documentation that BDR relied upon to form the conclusions documented throughout the BDR report; including but not limited to:

   (i) Cost structures;

   (ii) Non-financial impacts;

   (iii) Purchase price and expected financial burdens;

   (iv) Scenarios for estimating impact on harmonization of rates; and

   (v) Operating and Capital expenditure costs in relation to associated benefits.

b) Please confirm whether each of the items identified in response to part (a) was provided to BDR by EBN or obtained from public sources (as identified on Page 2 of the BDR report). If obtained from public sources, please provide a full and complete reference to such source so that it can be verified.

RESPONSES

(a) and (b)

BDR relied upon all of the evidence filed in this proceeding and all of the documentation referenced in the BDR report, all of which was obtained from public sources (references are included in the report). Please also see the response to Norfolk IR #1(f).

In addition, BDR examined:

- Norfolk Power Distribution Inc., EB-2011-0272, Exhibit 2, Tab 1, Schedule 1, Page 2 of 9, Filed: August 26, 2011
- OEB 2012 Yearbook of Electricity Distributors, published August 22, 2013 obtained in MS Excel format from the Board's website as 2012_Electricity_Yearbook_excel.xls.
- Report of Pacific Economics Group Research, LLC, Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board
- Table provided in Section 3.2, which was compiled by BDR as each transaction occurred, based on data available at the time.
- NPDI Revised Rate Order dated May 24, 2012 in EB-2011-0272
- EB-2013-0416, Exhibit G1, which at Tab 2, Schedule 1
- EB-2013-0416, Exhibit G1, Tab 4, Schedule 2, Attachment 5

All of the above documents, except the Table in Section 3.2, were obtained from the Board's website.

NORFOLK POWER INC. INTERROGATORY #4

Reference:

BDR Report, Section 2.1, page 9

Preamble:

Norfolk would like specifics on what informs the considerations BDR made as described on page 9 where, in its "test" of the evidence before the Board in this proceeding, BDR states that it considered:

> "whether it appears consistent with what we know of the way business is generally carried on by electricity distributors. Here we drew on our own sector experience and ***our consultation with senior management with EBN on facts and experience related to current operations of LDCs. (italics added)***

INTERROGATORY

a) Please identify and describe all "facts and experience related to current operations of LDCs" which Essex, Bluewater and/or Niagara-on-the Lake senior management provided to you. Please provide copies of all correspondence with EBN related to the same.

RESPONSE

a) The "facts and experience" involve general discussions as to the key functions of LDCs to identify and check for completeness the list that makes up the table on pages 14 through 16 of the BDR report. There is no correspondence related to the same. Please also see the response to Norfolk Power IR #1 (f).

NORFOLK POWER INC. INTERROGATORY #5

Reference:

BDR Report, Section 3.2, page 20 and Toronto Star, February 10, 2010 “The Push for the Privatization of Toronto Hydro” (attached).

Preamble:

Norfolk wants to clarify Section 3.2 as the Table found on page 21 of the BDR report indicates that from June 2000 to September 2005 “the average premium paid by publically owned distribution companies including Hydro One was about 30% to 40%.”

In the attached Toronto Star article, Mr. McNeil is quoted as saying “the city (Toronto) should look at dealing Toronto Hydro. It would command a feeding frenzy in terms of investor interest.”

INTERROGATORIES

a) To what extent are premium levels paid on LDC sales a function of competitive market forces where multiple buyers compete against each other?

b) Does BDR believe that only a utility the size of Toronto Hydro would generate, in Mr. McNeil’s words, “a feeding frenzy of investor interest” or does BDR believe that smaller LDCs, like Norfolk Power, could also attract significant premium offers from multiple, competing investors?

RESPONSES:

a) Premiums paid on LDC sales are a function of a combination of competitive market forces at the time, but are usually limited by the ability of any specific bidder to pay, combined with the expectations of individual bidders as to the financial and/or strategic benefits of the purchase, given that the regulatory framework precludes incorporation of the premium into rate base.

In BDR’s experience, the competitive effect of bids in any specific transaction goes well beyond the establishment of a price for that transaction. BDR maintains information to the degree available on premiums achieved to provide a benchmark for evaluation of the decision as to whether to continue holding an interest in an LDC or offer that interest for sale; or alternatively, to advise a prospective purchaser as to the bid level that might be necessary to make a shareholder willing to consider a sale. As such, the premiums established by prior transactions compete with premiums offered in a current transaction and also with the option that an LDC shareholder has of not selling.

b) There is extensive evidence that small and medium LDCs can attract, and have attracted, multiple competing purchase offers, whether for 100% interest or for a partial interest. A recent example is the transaction in which PowerStream acquired a partial interest in COLLUS Power, after its bid was selected from several alternative bids.

BDR does consider, however, that there is an important distinction between the degree of competition for small and medium utilities and for a large utility like Hydro One or Toronto Hydro. We expect that small and medium utilities, if offered for sale, would be of interest mainly to purchasers who already operate an Ontario LDC or related business, in order to be able to support the premium through cost synergies achieved in those businesses. However, the largest LDCs, or an interest in them, might be attractive to a purely financial investor, or to a similar operating company from outside the province, either of whom would be prepared to operate the purchased business unit through a management team, without an immediate expectation of benefits from consolidation of operations. As an example, some years ago BDR advised National Grid, a large utility with operations in Britain and the United States, in an attempt to acquire a 49% interest in Hydro One. The entry of such competition into the market would put pressure on the competing offers received, and explains why Mr. McNeil anticipated a “feeding frenzy” if an LDC like Toronto Hydro were to be offered for sale.

NORFOLK POWER INC. INTERROGATORY #6

Reference:

BDR report, Section 3.2, pages 20 to 22, "The Ontario LDC M&A Market", December 12, 2013 Schools Motion, Norfolk Exhibit and May 21, 2013 email from Joe Barile to multiple recipients entitled "LDC MADD Intervention (HONI purchase of Norfolk)" (attached).

Preamble:

The BDR report includes a Table on page 21 showing the outcome of various LDC sales solicitation processes. Mr. Barile's email, in the Background section, states that "HONI was the successful proponent in the RFP process initiated by Norfolk Power Distribution Inc."

INTERROGATORY

a) Please confirm that Essex Power Corporation signed a Confidentiality Agreement with Norfolk County dated December 3, 2012 which entitled Essex to receive, and which Essex subsequently did receive, the RFP package pertaining to the sale of Norfolk Hydro?

RESPONSE

The premise of the question appears to be that the May 21, 2013 Barile email was a source of information relied upon for the BDR report. BDR did not review this email prior to filing its report.