Hydro One Networks Inc.
8th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5707
Fax: (416) 345-5866
Andrew.skalski@HydroOne.com

Andrew Skalski
Director – Major Projects and Partnerships
Regulatory Affairs

BY COURIER

June 14, 2013

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

EB-2013-0053 – Hydro One Networks Inc.'s Section 92 – Guelph Area Transmission Refurbishment Project – Motion Materials

I am attaching two (2) paper copies of Hydro One Networks Inc.'s motion materials.

An electronic copy of the motion materials have been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY JOANNE RICHARDSON ON BEHALF OF ANDREW SKALSKI

Andrew Skalski

Attach.

c. EB-2013-0053 Intervenors

Hydro One Networks Inc. Compendium Index

EB-2013-0053 Oral Hearing for Motion – June 18, 2013

1. OEB Decision on Motion and Procedural Order No. 8 (EB-2011-0120 January 20, 2012)
2. OEB Decision and Order on Motions (EB-2007-0707 July 29, 2008)
3. OEB Decision and Order (EB-2005-0520 May 11, 2006)
4. Federal Court Judgment - Intel Corp. v. 3395383 Canada Inc.(February 11, 2004)
5. Environmental Defence Interrogatory #6 (I-2-6)
6. First Nations & Metis Consultation Process (B-6-6)
7. Stakeholder and Community Consultation (B-6-5)
8. Ontario Energy Board Interrogatory #1 (I-1-1)
9. Letters of Endorsement for the Project (B-6-2)
    - Attachment 1 – Guelph Hydro (Barry Chuddy)
    - Attachment 2 – Guelph Hydro (Kazi Marouf)
    - Attachment 3 – City of Guelph (Ann Pappert)
    - Attachment 4 – Kitchener-Wilmot Hydro (J. Van Ooteghem)
    - Attachment 5 – Cambridge and North Dumfries Hydro Inc. (Ian Miles)
    - Attachment 6 – Waterloo North Hydro Inc. (Rene W. Gatien)
10. Environmental Defence Interrogatory #39 (I-2-39)
11. Ontario Power Authority Evidence (B-1-5)
12. Environmental Defence Interrogatory #30

    Draft Kitchener-Waterloo-Cambridge-Guelph (KWCG) Integrated Regional Resource Planning Report (IRRP) 2013

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2011-0120

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 Canadian Distributed Antenna Systems Coalition for certain orders under the *Ontario Energy Board Act, 1998*.

BEFORE: Cynthia Chaplin
Vice Chair and Presiding Member

Ken Quesnelle
Member

Karen Taylor
Member

DECISION ON MOTION AND PROCEDURAL ORDER NO. 8

January 20, 2012

THE PROCEEDING

The Canadian Distributed Antenna Systems Coalition ("CANDAS") filed an application on April 25, 2011, subsequently amended by letters dated May 3 and June 7, 2011, seeking the following orders of the Board:

1. Orders under subsections 70(1.1) and 74(1) of the *Ontario Energy Board Act, 1998* (the "Act"): (i) determining that the Board's RP-2003-0249 Decision and Order dated March 7, 2005 (the "CCTA Order") requires electricity distributors to provide "Canadian carriers", as that term is defined in the *Telecommunications Act*, S.C. 1993, c. 38, with access to electricity

distributor's poles for the purpose of attaching wireless equipment, including wireless components of distributed antenna systems ("DAS"); and (ii) directing all licensed electricity distributors to provide access if they are not so doing;

2. in the alternative, an Order under subsection 74(1) of the Act amending the licences of all electricity distributors requiring them to provide Canadian carriers with timely access to the power poles of such distributors for the purpose of attaching wireless equipment, including wireless components of DAS;

3. an Order under subsections 74(1) and 70(2)(c) of the Act amending the licences of all licensed electricity distributors requiring them to include, in their Conditions of Service, the terms and conditions of access to power poles by Canadian carriers, including the terms and conditions of access for the purpose of deploying the wireless and wireline components of DAS, such terms and conditions to provide for, without limitation: commercially reasonable procedures for the timely processing of applications for attachments and the performance of the work required to prepare poles for attachments ("Make Ready Work"); technical requirements that are consistent with applicable safety regulations and standards; and a standard form of licensed occupancy agreement, such agreement to provide for attachment permits with terms of at least 15 years from the date of attachment and for commercially reasonable renewal rights;

4. its costs of this proceeding in a fashion and quantum to be decided by the Board pursuant to section 30 of the Act; and

5. such further and other relief as the Board may consider just and reasonable.

THE THESL MOTION

On December 22, 2011, Toronto Hydro Electric Systems Limited ("THESL") filed a Notice of Motion for an order of the Board requiring CANDAS to provide further and better responses to certain interrogatories ("IRs") filed by THESL and the Canadian Electricity Association ("CEA").

THESL's Motion requests that CANDAS be compelled to provide responsive answers to THESL IR Nos. 1(d) and (e), 18(a), 19(d), and 50, and CEA IR Nos. 19(b), 33, and 60[1] (the "Disputed IRs"). THESL asserts that the Disputed IRs seek material that is relevant to the matters in issue in this proceeding and are necessary for the Board and parties to conduct a fair and complete examination of the record. THESL submits that the Disputed IRs relate to two general areas of inquiry with respect to the attachment of wireless attachments:

- What are the rates paid in Toronto on non-utility poles? (Public Mobile)
- What are the rates paid in other jurisdictions? (ExteNet Systems)

CANDAS declined to provide responses to the above referenced IRs on the basis that the requested material was either not relevant or would be unduly onerous to produce relative to its probative value, if any, or in some cases, both.

The Board determined that it would hear the THESL Motion in writing and provided dates for written submissions in Procedural Order No. 7, issued December 23, 2011.

In considering THESL's Motion, the Board is guided by the principles of relevance and proportionality. With respect to relevance, the Board requires the production of responses that are relevant to one or more of the issues in this proceeding. The Board has previously enumerated the issues which are before it in this case, namely:

1. Does the CCTA decision apply to the attachment of wireless equipment, including DAS components, to distribution poles?
2. If the answer to 1 is no, then should the Board require distributors to provide access for the attachment of wireless equipment, including DAS components, to distribution poles?
3. If the Board requires distributors to provide access for the attachment of wireless equipment, including DAS components, under what terms and conditions should those arrangement be governed?

These issues will guide the Board in determining the relevance of the Disputed IRs that are the subject of the THESL Motion.

[1] THESL adopted the evidence of CEA; CANDAS did not object.

With respect to proportionality, the Board considers the time and resources that may be required to produce the responses relative to the probative value of the evidence that is ultimately expected to be produced.

THE DISPUTED IRs

The Disputed IRs fall into two broad categories of information requests:

- the Macro Cell alternative to the Toronto DAS Network that Public Mobile is currently using (THESL IRs 1(d), 1(e) and 50 and CEA IRs 19(b)[2] and 60; and
- wireless attachment rates and terms in other jurisdictions (ExteNet Systems) (THESL IRS 18(a), 19(d) and CEA IR 33.)

THE MACRO CELL ALTERNATIVE

CANDAS responded that the information requested in THESL IR 1(d) and 1(e), and CEA 19(b) is not relevant to the issues raised in the Application.[3,4] CANDAS also indicated at that response that it did not understand the relevance of parts (a)-(o) of THESL IR 50, and that that producing the information would be unduly onerous relative to the probative value, if any.

CANDAS responded to the three-part CEA IR 60 indicating that: (a) there is no operating DAS network in Toronto, (b) the information requested is not relevant, and (c) directing CEA to review the entirety of Mr. O'Shaughnessy's written evidence.[5]

CANDAS replied that THESL's submission on motion "focus entirely" on pricing information, which falls outside the scope of this proceeding.[6] CANDAS also submitted that relevance of the price of Public Mobile's network is based on the disputed contention that rates should be market-based and/or that Macro Cell is a direct substitute for smaller-cell topologies such as DAS.[7] CANDAS submitted that the cost of deploying Macro Cell is not relevant to determining an electricity distributor's costs of maintaining a pole network.

[2] CEA IR 19(b) was identical to THESL IR 1(d)
[3] CANDAS Response to Interrogatories of THESL, August 16, 2011
[4] CANDAS Response to Interrogatories of CEA, August 19, 2011
[5] Ibid.
[6] CANDAS response to THESL submission on motion, January 10, 2012, p.9, para 27, 28
[7] Ibid, p.10, para 32

THESL submitted in its submissions on motion that this group of interrogatories is directly relevant to the issues raised in the Application, noting that CANDAS' claims that LDC poles constitute essential facilities for Canadian carriers seeking to make wireless attachments, and at the same time it is CANDAS' evidence that Public Mobile was able to launch its Toronto service without use of power poles.[8] THESL submitted that CANDAS' evidence is contradictory.

THESL further submitted that pricing information with respect to the costs to make wireless attachments for a known feasible alternative option for launching a Toronto telecommunications wireless network would assist the Board in examining comparable costs of substitutable technology for launching a wireless network that is functionally comparable to the proposed Toronto DAS Network. THESL suggested that the information is necessary to enable a fair and complete examination of the record.

THESL submitted that evidence in this proceeding suggests that the Macro Cell alternative is not "temporary", as characterized by CANDAS, and that it is CANDAS' evidence that Public Mobile considers Macro Cell a direct substitute for DAS.[9] THESL submitted that there is no information about other vendors that are in direct competition with THESL utility poles or the rates for equivalent service to the proposed Toronto DAS Network.

THESL submitted that CANDAS' did not provide any particulars to its claim that production of THESL IR 50 and CEA IR 19(b) would be unduly onerous, and CANDAS did not respond in its reply.

Board Finding

The Board has determined that the information that is currently on the record with respect to the comparability of other wireless systems is sufficient for the purposes of addressing the issues before the Board at this time. The Board will not require the filing of further information from CANDAS regarding the specific costs or specific technical aspects of the Macro Cell system used by Public Mobile in Toronto. The Board distinguishes this information from that which THESL has been ordered to produce. The Board has already determined in its December 9, 2011 decision and order that the price THESL charges for other wireless attachments is directly relevant to the issues

[8] THESL submission on motion, January 3, 2012, p.10, para 35
[9] THESL submission on motion, January 3, 2012, p.12, para 42

before the Board. That information is different from that requested under the current motion. The Board concludes that pricing information for potential non-utility substitutes is not required at this time.

WIRELESS ATTACHMENT RATES AND TERMS IN OTHER JURISDICTIONS

CANDAS originally responded to THESL IR 18(a) by providing two redacted copies of "representative" attachment agreements between ExteNet Systems and utility companies, removing pricing and other information. CANDAS did not set out the reasons for its redaction, nor did CANDAS indicate the reason for its refusal to provide the remaining 78 agreements as part of its original response to THESL IR 18(a).

CANDAS' response to THESL IR 19(d) indicated that producing the information requested would be unduly onerous relative to its probative value, if any. CANDAS' response to THESL 19(d) and CEA IR 33 indicated that the information requested is not relevant to the issues raised by its application. CANDAS reiterated in its reply to the motion that the information sought was either unduly onerous, not relevant, or both.

CANDAS replied to the motion stating that information pertaining to access to poles in other jurisdictions is wholly extraneous to the costs of Ontario electricity distributors, and the manner in which they are supervised by the Board. CANDAS submitted that the best evidence for purposes of rate-setting by the Board would be costs actually incurred in Ontario by electricity distributors.[10]

THESL submitted that the representative agreements provided by CANDAS in response to THESL IR 18(a) were redacted to exclude pricing information, among other things, and that CANDAS did not request confidential treatment of the information as required under Rule 10 of the Board's *Rules of Practice and Procedure* and the Board's *Practice Direction on Confidential Filings.*

THESL indicated that it had asked for the 80 agreements that ExteNet Systems entered into, and that CANDAS did not refuse to provide the information on the basis of relevance, or for any other specified reason, in its failure to respond.

THESL submitted that the information requested in THESL IR 19(d) and CEA IR 33 is relevant as it would indicate the price history as well as variation from jurisdiction to jurisdiction. THESL submitted that allowing CANDAS to produce only a sampling of the

[10] CANDAS response to THESL submission on motion, January 10, 2012, p.12, para 39

relevant agreements would risk allowing CANDAS to selectively pick the most favourable “sample” terms and conditions. THESL submitted that CANDAS did not provide any argument or particulars of its claim that producing the information in THESL IR 19(d) would be unduly onerous.

Board Finding

The Board has determined that for the purposes of the issues before it, pricing information for attachments in other jurisdictions is not required at this time. The Board is further of the view that it does not need further information regarding the terms and conditions of attachments in other jurisdictions. The sample agreements filed as part of CANDAS’ response to THESL IR 18(a) are sufficient at this time.

THESL’S RESPONSE TO THE BOARD’S DECEMBER 9, 2011 ORDER

The Board issued a Decision and Order on December 9, 2011 ordering THESL to provide additional information by December 23, 2011. THESL filed a letter on December 13, 2011 indicating that it would be able to produce some responses on December 23, 2011, but that satisfying the remaining requests made pursuant to the Order would require significant time and resources. THESL indicated it would make best efforts to generate the requested information as soon as possible. Some of the material was filed on December 23, 2011.

By letter dated January 11, 2012, THESL reported that it was continuing to make best efforts to file the information identified in the Board’s Decision and Order of December 9, 2011. The letter further set out the company’s estimates of when it expects to complete its filing of the ordered information. Although THESL has not formally sought and extension to the deadline in the Board’s decision and order, the Board will treat THESL’s January 11 letter as a formal request for an extension.

The Board is prepared to accept the filing date of January 20, 2012, as proposed by THESL, for the materials related to other wireless communications on THESL’s poles. The Board will grant an extension to that date.

The Board does not believe the filing date of February 17, 2012 for the balance of the outstanding materials is appropriate in terms of ensuring an expeditious completion of this proceeding. The Board notes that a further letter from THESL dated January 19, 2012 sets out the significant volume of data involved and requests the Board consider a more limited scope of information. The Consumers Council of Canada ("CCC") responded to THESL's January 19th letter seeking clarification in respect of two issues.

The Board is interested in ensuring a practical approach to the resolution of this matter. For this reason, the Board will order THESL to file a subset of the information originally ordered to be produced. After that, the Board will convene an oral hearing to hear any claims of privilege and/or confidentiality that the company makes in relation to any of the materials and to address the issue of any remaining information outstanding under the December 9, 2011 Decision and Order.

The balance of the outstanding requirements for further information, as set out in the order fall into two categories: information related to the THESL letter to the Board of August 13, 2010; and information related to safety concerns. THESL proposes to file that information by February 17, 2012.

With respect to the first category, the Board's December 9, 2011 Decision and Order states:

> The Board will therefore require THESL to produce the information and material requested in CANDAS IR 1(h) and CCC IR 1.

Those IRs read as follows:

- CANDAS IR 1(h): Were any presentations (oral or in writing) made to the THESL Board of Directors in relation to any of the subjects discussed in the THESL Letter, prior to the letter being filed with the Ontario Energy Board ("Board")? If yes, provide particulars of any oral presentations and copies of any written presentations, including, without limitation, power points, notes, memoranda, executive summaries and any similar writing.

- CCC IR 1: Please provide copies of all reports, analyses, written communications, including email, with respect to the policy referred to in the letter of August 13, 2010. Please include copies of all reports to THESL's management and board of directors with respect to that policy.

The Board will now require that the following information be provided by January 30, 2012:

> *Copies of any presentations or reports provided to the THESL Board of Directors or THESL senior management in relation to the subjects discussed in the THESL letter to the Board of August 13, 2010. Only materials which were provided to the Board of Directors or senior management during June, July or August 2010 shall be provided at this time.*

With respect to the second category, the Board's December 9, 2011 Decision and Order states:

> The Board therefore orders THESL to:
>
> a) provide copies of all reports including incident reports, analyses and communication, in support of the contention that wireless attachments impair operations efficiency and present incremental safety hazards to electricity distribution; and
> b) provide copies of all reports, analyses, and communications, reporting on the issues described in paragraphs 42 to 46, of Ms Byrne's Affidavit.

The Board will require the following information to be provided by January 30, 2012:

> *a) copies of reports, including incident reports and analysis reports, that provide a representative sample of all the reports in support of the contention that wireless attachments impair operations efficiency and present incremental safety hazards to electricity distribution; and*
>
> *b) any reports on the issues described in paragraphs 42 to 46 of Ms. Byrne's Affidavit.*

THE BOARD ORDERS THAT:

1. THESL shall file the subset responses to interrogatories as described by the Board herein **on or before Monday, January 30, 2012**.

2. A hearing will be held on **Monday, February 6, 2012** at 9:30 a.m. at 2300 Yonge Street, Toronto in the Board's hearing rooms on the 25th Floor with the objective of:

   (a) hearing submissions with respect to any claims of privilege or confidentiality made by THESL in respect of the subset of interrogatory responses required to be filed by THESL in accordance with this Decision on Motion and Procedural Order No. 8 or the materials that are expected to be filed on January 20, 2012;

   (b) determining whether, to what extent and by what date the balance of the outstanding requirements for further information as set out in the Board's December 9, 2011 Decision and Order are required; and

   (c) considering and setting remaining procedural dates for the proceeding.

DATED at Toronto, January 20, 2012.

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Ontario Energy Board
P.O. Box 2319
27th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'Énergie de l'Ontario
C.P. 2319
27em étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone; 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

BY EMAIL

July 29, 2008

Miriam Heinz
Regulatory Coordinator
Ontario Power Authority
120 Adelaide St W., Suite 1600
Toronto ON M5H 1T1

Dear Ms Heinz:

Re: Ontario Power Authority
Application for Review and Approval of the OPA Integrated Power System Plan and Procurement Processes
Decision and Order on Motions
Board File No. EB-2007-0707

The Board has today issued its Decision and Order on Motions in the above matter.

Yours truly,

Original signed by

Kirsten Walli
Board Secretary

cc: Intervenors of Record

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0707

IN THE MATTER OF sections 25.30 and 25.31 of the *Electricity Act, 1998*;

AND IN THE MATTER OF an application by the Ontario Power Authority for review and approval of the Integrated Power System Plan and proposed procurement processes;

AND IN THE MATTER OF Notices of Motion brought by various parties requiring further and better answers to interrogatories from the Ontario Power Authority.

BEFORE: Pamela Nowina
Presiding Member and Vice-Chair

Ken Quesnelle
Member

David Balsillie
Member

DECISION AND ORDER ON MOTIONS RELATED TO INTERROGATORY RESPONSES OF THE ONTARIO POWER AUTHORITY

BACKGROUND

The Ontario Power Authority (the “OPA”) filed an application with the Ontario Energy Board dated August 29, 2007 under the *Electricity Act, 1998,* S.O. 1998, c.15, Sched. A. The applicant is seeking an order of the Board approving the Integrated Power System Plan (the “IPSP” or the “Plan”) and certain procurement processes. The Board has assigned file number EB-2007-0707 to this application.

Part 1 of this proceeding was completed with the issuance by the Board on March 26, 2008, of an Issues Decision establishing an Issues List for the proceeding.

On April 8, 2008, the Board issued Procedural Order No. 3, setting out procedural steps for its review of the IPSP and the procurement processes. These steps included an opportunity for Board staff and intervenors to request further information from the OPA by way of written interrogatories. The OPA filed its responses to the majority of interrogatories on June 18, 2008.

On May 16, 2008, the OPA filed additional evidence related to Aboriginal consultation. On May 23, 2008, the Board issued Procedural No. 4 which provided an opportunity for interrogatories on the additional evidence. The OPA filed its responses on June 25, 2008.

In its Decision dated June 25, 2008, the Board granted, in part, two motions that sought an extension to certain filing in Procedural Order No. 3. Procedural Order No. 6 issued on the same date, contained the revised dates and made provision for the hearing of any motions seeking further and better answers to interrogatories from the OPA .

MOTIONS RECEIVED

Notices of Motion seeking further and better interrogatory answers from OPA were received from the following parties:

> The National Chief’s Office on behalf of the Assembly of First Nations (“NCO”)
> Bullfrog Power Inc.
> City of Thunder Bay, Northwestern Ontario Municipal Association, and Town of Atikokan (“NOMA”)
> Council of Canadians

Green Energy Coalition, Pembina Foundation and Ontario Sustainable Energy Association (“GEC”)
Xylene Power Ltd. (“Xylene”)

A notice of motion was also received from Energy Probe. OPA objected to this motion on the grounds of late filing. The Board declined to hear the motion due to it being filed later than the date required in Procedural Order #6.

By letter dated July 11, 2008, the Council of Canadians advised the Board that it had come to an agreement with the OPA and withdrew its motion.

By letter dated July 14, 2008, Bullfrog Power Inc. withdrew its motion.

The remaining four motions were heard on July 15 and 16, 2008. The parties to the proceeding were represented as follows:

City of Toronto	Ian Mondrow Elisabeth DeMarco
Electricity Distributors Association	Chris Buckler
GEC	David Poch
Ontario Ministry of Energy And Infrastructure	Suzanne Coultes
NCO	Paul Manning
Nishnawbe Aski Nation	Doug Cunningham
NOMA	Nick Melchiorre
Saugeen Ojibway Nations	Alex Monem
Xylene	Dr. Charles Rhodes
OPA	George Vegh Kristyn Annis
Board Staff	Jennifer Lea David Crocker

In the Board's Issues Decision dated March 26, 2008 it stated:

> "…the Issues List has two purposes: 1) it defines the scope of the proceeding; and 2) it articulates the questions which the Board must address in reaching a decision on the application. The Board does not believe it is appropriate to define the Issues List in complete detail. For many of the issues, the Board expects that sub-issues will arise during the course of the proceeding which will need to be addressed in argument and in the final decision. It is not possible to identify all of these detailed issues now so early in the process."

In reviewing the motions the Board has considered the requests for better and further interrogatory ("IR") answers in relation to the scope of the issues as defined in the Issues List and whether such answers would assist the Board in reaching a decision on the application.

This Decision and Order addresses the motions filed by NCO, GEC, NOMA, and Xylene.

FINDINGS

Introduction

Collectively, there were approximately 160 interrogatories in question as a result of the Motions of NCO, GEC, NOMA and Xylene Power. Of these more than 60 were broad requests for information.

The paramount consideration for the Board is to have available to it the information it requires to be able, at the end of the hearing process, to make the necessary well-reasoned decision on the IPSP. At the same time, the Board wishes to ensure that the hearing is completed within a reasonable timeframe so that the results of the process are meaningful and useful. In this light, the Board in this decision has not ordered the wholesale production of documents that are not defined with sufficient precision by the party making the request. In some cases, requests for "all background information" might lead to the production of thousands, even tens of thousands, of pages of documents. For example, the results of internet searches performed by the OPA, given its planning function, could be vast and might be captured by such requests.

If it can be demonstrated that such information could have significant probative value, the Board might well order such production. However, the Board sees little value in ordering the production of voluminous materials where it is not clear what, if any, value this will add to the proceeding. Even in a proceeding as extensive and lengthy as the IPSP, there is a limit to the amount of material that the Board can effectively review. The Board has on that basis denied some requests for additional information, and in other cases, refined or focused the requests and ordered the OPA to respond to these refined requests.

The National Chief's Office on behalf of the Assembly of First Nations

The NCO brought a motion for further and better answers to its written interrogatories from the OPA. The NCO asked four questions with respect to specific interrogatories it posed. In addition, at the outset of his submissions, counsel for the NCO reiterated certain issues first raised in the issues proceeding with respect to whether the IPSP and the procurement process provide First Nations with fair, open, non-discriminatory access to and full participation in that procurement process.

Mr. Vegh for the OPA argued, with respect to this position, that removing systemic discrimination and barriers against Aboriginal peoples is not the responsibility of the OPA or the OEB.

The Board finds that this question can and should be raised during the hearing proper. It need not be dealt with at this preliminary stage of the proceedings.

With respect to the specific issues raised by the NCO, the Board finds as follows:

<u>Question 1</u>

In its Motion and oral submission, the NCO argued that the OPA should obtain from the Ministry of Energy ("MOE")substantive answers to all NCO interrogatories submitted to the OPA as requested by the NCO's letter to the OPA dated June 9, 2008 and to further and better answers requested by this Notice of Motion.

Mr. Vegh submitted that all of the information in its possession related to the NCO's interrogatories had been filed with the Board and that there was nothing further it could provide at this time. He stated that OPA staff had been in touch with the MOE regarding the NCO's requests for further information. The result of those discussions was given in a letter from the OPA dated June 27, 2008, filed with the Board, which stated that, "the Ministry has reviewed the OPA's interrogatory responses and has advised that it has no further comments on the responses provided by the OPA."

The Board accepts the submission of counsel for the OPA that no further information is available to the OPA. The Board expects that the OPA will continue to be in contact with the MOE as this process moves forward and will bring to the hearing any new information from the MOE with respect to this issue if such information should become available. In addition, the Board notes that the OPA can be cross-examined on this issue by the parties.

Question 2 – IRs No. 3 and No. 4

IRs No. 3 and No. 4 asked for the OPA's view of its legal duty to engage, consult and accommodate in relation to the IPSP and Procurement Process, and the OPA's view of its role in relation to the Crown's duty to consult. Through its Motion, the NCO asked the OPA what arrangements or agreements, formal or otherwise, exist between the Crown and the OPA, regarding the allocation of responsibilities, procedural or otherwise, to consult with and accommodate First Nations in relation to the IPSP.

The Board has considered the written and oral responses of the OPA to this question. The Board accepts the position of the OPA that the question raised in the Motion is different than that presented in the original NCO interrogatories. In any event, the Board finds that the responses of the OPA are adequate. Once again, the Board notes that the parties will have an opportunity to cross-examine the OPA on this issue at the hearing.

Question 3 – IRs No. 5, and 7(b),(c) and (d)

Mr. Manning asked how issues requiring accommodation that arise during the proceeding or otherwise during the life of the IPSP will be incorporated into the IPSP.

Mr. Vegh, once again, submitted that this question is really a new interrogatory and the Board agrees. Mr. Vegh submitted, nevertheless, that all information on accommodations that are part of the IPSP has been provided and there is nothing that the OPA can add. Mr. Vegh also notes that long-term power system planning will continue and that an ongoing dialogue with First Nations will also continue. He stated that it was the intention of the OPA to develop a process through 2008 and into 2009 for future engagement with First Nations on this long-term power planning.

In paragraph 14 of the written motion, the NCO indicates that a delay in receiving the information requested by way of the motion would be prejudicial to the NCO. Counsel was asked during oral submissions to indicate how the NCO would be prejudiced by delay.

Mr. Manning responded that insofar as the OPA responses fall short of the information the NCO would like to have they are faced with having to consider developing information on their own.

The NCO submitted that they have not been able to ascertain the mandate of the OPA with regard to consultation and accommodation and whether or not its obligations are limited at this stage. Therefore they do not have a clear idea as to what remains to be done in terms of the production of evidence.

The Board was not persuaded by the response of Mr. Manning that it should order a further response to interrogatories at this time. The Board has found that the OPA has responded to the interrogatories with the information presently available to it. The NCO should conduct itself based on the record as it stands now. The issues raised by this question will be a continuing subject of the hearing.

The Board notes that it remains the burden of the applicant to satisfy the Board that whatever consultation or accommodation might be required has been made. The fact that the Board has not ordered further and better responses to interrogatories with respect to this matter at this time, does not relieve the applicant of this burden.

Question 4 – IRs 12 and 13

Mr. Manning in his oral and written submissions, reiterated interrogatories 12, 13 and 15. These requested identification of all projects in the IPSP related to First Nations' interests. In his oral submissions, however, Mr. Manning narrowed his original request so that it related to First Nations Reserve Land; other land owned by First Nations, whether through corporations or otherwise; land over which First Nations' rights are established; and other land over which First Nations' rights are asserted.

Mr. Vegh submitted that providing such information would be extremely difficult, time consuming and be of limited probative value.

The Board finds that the provision of some additional information in response to this request is reasonable and would be helpful to the Board. The Board further narrows the information required and orders the OPA to provide an answer which identifies all projects within the IPSP that affect or may affect First Nations Reserve and Treaty Lands. This listing should include any projects on which work is done or money committed or for which development is expected to occur during the following three time frames:

- 2007 and 2010
- 2010 and 2013
- beyond 2013.

The listing should be divided by these time fames.

Green Energy Coalition, Pembina Foundation and Ontario Sustainable Energy Association

GEC requested a large amount of additional background information as well as copies of the models and the data inputs and outputs for those models that the OPA had used in developing its Plan. GEC broke down its requests into four groups:

- Background information and studies
- Models, spreadsheets and workpapers
- Data inputs and outputs
- Other non-responsive interrogatories

GEC gave a number of grounds for its requests. GEC stated that the interrogatory responses were necessary to allow their experts to:

- Understand the specific assumptions where the pre-filed evidence does not break out details;
- Understand what information the OPA has decided not to rely upon;
- Understand the implicit decision making rules embedded in the various models;
- Test whether the OPA’s models in fact do what they are described as doing;

- Assess whether logic, data or computational errors have occurred;
- Understand tradeoffs at the margin that are embedded in the models or the data;
- Assess the reasonableness and economic prudence of the OPA's case;
- Understand how alternative assumptions would affect the OPA's Plan outcomes; and
- Confirm that their analysis reflects the OPA's assumptions correctly.

The Board addresses this motion using the same four categories used by GEC.

Background information and studies

GEC requested all background information and studies that the OPA considered in developing its Plan in relation to 29 of its interrogatories or parts of its interrogatories.

GEC requested all background information that the OPA has related to:

- Conservation and Demand Management ("CDM") performance of Ontario's local distribution companies and distributors of other jurisdictions as well as avoided CDM costs;
- Cogeneration potential in Ontario;
- Real-time and time-dependent electricity pricing programs;
- Power system nuclear integration and projected nuclear outage rates;
- Overall Plan operability, impact on the Plan of major project delays and suitability of interconnections to meet supply needs;
- Greenhouse gas reduction, reporting and related issues.

At the hearing into the motion Mr. Poch, counsel for GEC proposed to narrow the request to the information, studies, or memos created either by, or for, the OPA, or other documents that are of particular relevance to the choices the OPA made.

Mr. Poch commented that the OPA had not suggested that the information GEC was seeking was out of scope, nor did it deny that there were additional studies or background material.

Mr. Cunningham, Counsel to the Nishnawbe Aski Nation, indicated its support of GEC's motion.

Mr. Mondrow, Counsel for the City of Toronto, stated that his client had a keen interest in the treatment of CDM and alternative energy options by the OPA and was supportive of GEC's request for further information. His client was sympathetic to the concerns of OPA with regard to the scope of concerns and the effort required to put the requested information on the record, saying it would endorse more rigour on the part of GEC in making its requests. However, he also stated that his client would support the provision of additional information by the OPA to address GEC's requests under careful direction from the Board.

Mr. Monem, Counsel for the Saugeen Ojibway Nations spoke in support of GEC's motion. He stated his client was particularly concerned regarding provision of further information with respect to renewable energy cost assumptions and assumptions underlying OPA's LUEC (Levelized Unit Energy Cost) analysis. He stated this information related to OPA's analysis of potential wind generation sites, which was of significant interest to his client.

Mr. Vegh, counsel for the OPA, stated that the OPA takes its responsibility as a public agency very seriously and that providing information and understanding of its application to the public is not only a legal requirement but necessary for the long term success of the IPSP process. However, the OPA stated, the unanswered requests for background information were too broad in scope and not specific. The OPA was concerned about the extent of effort that would be required to search for and gather the information requested and this effort, in its view, far outweighed the probative value of the information, especially in light of the considerable volume of information it had already provided. The OPA was concerned about the delays in the proceeding that would result from meeting these requests, delays that it believed could seriously threaten the relevance of the overall review process. Mr. Vegh noted that there would be opportunity for further discovery at the hearing.

The OPA pointed to the Board's Rules of Practice and Procedure in support of its position. Specifically, Mr. Vegh argued that Rule 28 stated that the purpose of interrogatories is to clarify evidence, simplify issues, to permit a full and satisfactory understanding of the matters to be considered and to expedite the proceeding. It was not to allow for an indiscriminate data search. Second, he pointed to Rule 28.02(d) that interrogatories shall contain specific requests for clarification of evidence, documents or other information in the possession of the party and relevant to the proceeding. GEC's requests did not meet the requirement for specificity. And finally he relied on Rule 29.02

(b) that addresses the situation where a party contends that the information requested is not available or cannot be provided with reasonable effort. Mr. Vegh argued that this was the situation in this case, that the effort required far outweighed the probative value of the additional information requested.

In his reply submission, Mr. Poch pointed to the request for nuclear integration studies as an example of a specific request, and in the absence of knowing what studies the OPA had, it was difficult to be more specific.

The Board understands GEC's position that it wishes to have detailed background information to gain a better understanding of the issues in this complex case. The subject areas of its requests are areas relevant to the Board. At the same time, the Board understands the position of OPA that the effort to fulfill all the requests raised by GEC will be very time consuming and could lead to delays in the hearing process.

The Board notes that there will be opportunity during the course of the hearing for further discovery through cross-examination.

The Board also notes that GEC's proposal to narrow its request focussed only on studies that were not conducted or commissioned by the OPA itself, GEC still requested all information the OPA had in its possession that OPA had undertaken itself or had commissioned. This is likely to be a large quantity of information and will require considerable time to produce.

Given these concerns the Board will not order the OPA to meet GEC's request for the filing of all background information in its possession in the areas identified by GEC. The Board agrees with the OPA that the requests were too broad and lacked specificity. In our introductory comments to these findings the Board has concluded that broad requests such as these are not helpful to the Board.

<u>Models, spreadsheets and work papers</u>

GEC requested the OPA to file models, spreadsheets and work papers that are used or support the responses the OPA provided to a number of interrogatories.

Mr. Poch noted that the OPA had refused to provide the information for all the models it used including what GEC viewed as simple non-licensed and non-proprietary Excel spreadsheets. Mr. Poch challenged the rationale for denial based on the need for training, arguing that GEC had retained its own experts who were very familiar with models and capable of interpreting, analyzing and utilising such models. It expected that at most some informal inquiries as to how something flows in the model would arise. With regard to the OPA's concern about disclosing licensed models, it stated that its experts are prepared to enter into appropriate non-disclosure agreements.

Mr. Poch noted that because of the fact the result of the model runs had been provided at the same time as the answers to interrogatories, there had not been an opportunity to ask questions about the results and to understand how they arose from the model runs. GEC stated it needed access to the models to get a better understanding as to how the models work and to examine the effects of changes in the model inputs and assumptions. GEC made reference to two instances where clarification of the model results would be helpful:

1. Model Run No. 2 "Applying historical nuclear unit performance" requested by Energy Probe
2. Model Run No. 3 "High nuclear costs" requested by GEC.

Mr. Poch stated it was never GEC's position that the undertaking of the model runs was a complete substitute for provision of the models, spreadsheets and workpapers. However GEC was prepared to narrow its request and seek filing of only five models:

- the Reserve and Insurance Requirement Calculator;
- the Capacity Planning Tool;
- the Profile Generator for Hydro;
- the Profile Generator for Wind; and
- the Portfolio Screening Model.

In its response to IR 41 the OPA outlined its reasons for refusing to provide the information. The OPA submitted that it had put considerable effort into producing model runs to assist intervenors and Board Staff. The OPA believed this approach was a more effective way to provide information rather than handing over the models and raw data to intervenors. The OPA held a seminar to explain the 40 or so models it used. It stated that the models were not off the shelf "plug and play" software that allowed simple runs. The OPA stated that in most cases there were no operations manuals, and the models often required interaction and the exercise of judgment. The OPA contended that if the models were provided to the intervenors it could take up to several months to provide instruction and assistance in how to use them. In addition, the OPA submitted that some of the models were subject to licensing and other proprietary restrictions. The OPA commented that it had spent considerable time handling GEC's particular requests.

In his oral submissions, Mr.Vegh reiterated these concerns and submitted that all models, even the Excel spreadsheets required explanations. He also noted that the outcomes of the model runs and the assumptions would be subject to cross-examination.

Mr. Vegh stated that GEC had failed to provide affidavit evidence from its expert consultants supporting its contention that the model runs prepared by the OPA were insufficient and that it faced prejudice in preparing its case in the absence of additional model runs.

With regard to the reduced set of models now sought by GEC, Mr. Vegh indicated that the Portfolio Screening Model and the Profile Generator for Hydro were large and complex and were proprietary models. The OPA still resisted the production of the other three models on a principled basis but acknowledged that the production of these models would not raise the same practical concerns for the other two models.

In an attempt to reach an accommodation with regard to GEC's request for access to the models, the Board wrote to GEC and the OPA seeking their comments on the following proposal:

> "The Board could require the OPA to provide to GEC's experts the opportunity to attend at the OPA's offices to join with OPA staff in completing one or more model runs employing assumptions and inputs as selected by GEC. The intention would be to have the GEC representatives be able to observe all phases of these model runs so that they could better understand such matters, as for example:
>
> - how the data input is carried out;
> - how the general logic structure and the model connectivity perform; and
> - if there are any embedded decision-making rules or trade-offs employed that they are unaware of."

The Board noted that GEC could then use the results in their cross-examination and in the preparation of their evidence. It stressed that this would not be an unlimited opportunity. Only a reasonable amount of OPA staff time would be involved; for example two or three business days. A representative of Board staff would also attend.

GEC responded that the Board's proposal was generally a workable solution while addressing the OPA's concerns. GEC suggested that providing the wind profile, capacity planning and reserve calculator models, for which it understood the OPA did not appear to have strong objection to disclosure, would help reduce the time required for study and runs at the OPA's offices. GEC, however, noted that its expert would not be available at the OPA's offices until some time during the first two weeks in August, and that while this would not permit GEC to address any new information in its written evidence, it would inform its cross-examination and if needed enable it to make corrections to its evidence. GEC stated that it considered the two or three days suggested by the Board for this initiative was about right assuming GEC could retain the input and outputs of the runs. GEC commented that it understood the OPA did not object to providing this data.

The OPA responded that while the OPA appreciated the Board's proposal as a way to address GEC's and the OPA's concerns, it believed that providing the three more manageable models to all parties was preferable to the Board's proposed process. Mr Vegh was concerned about the transparency, fairness and practicality of the proposed process. With regard to transparency, he stated that production of the models would put the information on the record, while in the proposed approach, the discussions would only be known to the parties present, namely GEC, OPA staff and the Board staff representative. With regard to fairness, he stated that providing GEC with the opportunity for additional model runs but not making this available to other parties seemed unfair. Since GEC had advised that its expert could not attend at the OPA's office until after GEC had filed its evidence, he questioned the value of the proposed process. He also raised concerns about the burden this proposal would put on OPA staff.

The Board attempted by its proposed approach to reach a resolution of the concern's of both GEC and the OPA with regard to the production of the models utilised by OPA in preparation of the IPSP. The Board has closely reviewed the comments received from GEC and the OPA. The Board notes that the question of production of models was raised only by the GEC. No other party requested production by Notice of Motion. The

Board also understands from Mr. Poch's statements that other parties have indicated to GEC that they are relying on the GEC to address issues surrounding the models. The Board notes that although all parties to the IPSP proceeding were copied with the Notices of Motion and made aware of the hearing dates, only counsel for the Saugeen Ojibway Nations, the City of Toronto and the Nishnawbe Aski Nation attended the hearing and spoke in support of GEC's request. The Board believes that the fairness concerns raised by the OPA with regard to the Board's proposed process are to a great extent mitigated by these facts. The Board accepts the statement of GEC's counsel that other parties are relying on GEC to test the validity of the models.

With regard to the OPA's concerns with regard to transparency, the Board believes that if the data inputs, assumptions and outputs of any model runs undertaken during the proposed process are placed on the record, the concerns of transparency are largely addressed. With regard to the concerns about practicality, while GEC will not have the results of the runs in time to prepare its evidence, GEC will have this information available to prepare cross-examination. This should result in more focused and effective cross-examination. Finally with regard to the OPA's concern about the added burden on its staff, the Board recognizes the burden the entire hearing places on the OPA staff. However, the Board believes that the additional value the resulting information may have for the Board out-weighs this concern.

The Board also notes the OPA's willingness to produce the three models, although the Board understands there may be some concerns from third parties with regard to the confidentiality of the data contained therein.

Because of their complexity and proprietary nature, the Board will not require production of the Portfolio Screening Model or the Profile Generator for Hydro.

The Board orders as follows:

1. The OPA shall provide to GEC copies of the Reserve and Insurance Calculator, the Capacity Planning Tool and the Profile Generator for Wind.

2. The OPA shall provide GEC with the assumptions, inputs and outputs from the three models provided.

3. The OPA shall provide to GEC's experts the opportunity to attend at the OPA's offices, to join with OPA staff in completing one or more model runs employing assumptions and inputs as selected by GEC. The intention is to have the GEC representatives be able to observe all phases of these model runs so that they can better understand such matters as, for example: how the data input is carried out; how the general logic structure and the model connectivity perform; and if there are any embedded decision-making rules or trade-offs employed that they are unaware of. This opportunity should be time-limited to no more than three business days. A Board staff representative will be in attendance.

4. GEC shall file all assumptions, inputs and outputs from the model runs on the public record.

5. GEC's counsel and experts, and any party that has access to confidential information as a result of this order of the Board, shall enter into a confidentiality agreement in the form specified in the Board's Rules of Practice and Procedure.

Data inputs and outputs

GEC requested the OPA to file the assumptions or raw data that was input to its various models and the outputs of its models.

The OPA's response to this request was that the data was of no value without the models and the OPA argued against providing the models. However, since the Board is directing the OPA to provide three models to GEC (the Reserve and Insurance Calculator, the Capacity Planning Tool and the Profile Generator for Wind), the Board also directs the OPA to provide sufficient input data for these models to allow GEC to effectively run their chosen simulations.

GEC's overall request for data which had not been provided by the applicant referred to seven separate GEC interrogatories. Five of those interrogatories involve proposed model runs of the Portfolio Screening Model. Since GEC will not have that particular model, this data is not required nor would it be useful.

The Board notes that two of the interrogatories (46b and 210) are not data inputs related to model runs and involve information that is likely available to the OPA. Interrogatory 46b involves data related to projected transmission investments for the Plan period and interrogatory 210 involves inputs for a probability distribution for resources at risk in the Plan for the year 2016. The Board has determined that it would be assisted by the replies to GEC interrogatories 46b and 210 and directs the OPA to provide a response.

<u>Other non-responsive interrogatories</u>

GEC and the OPA noted that three of the IRs in this grouping had been resolved in the July 11, 2008 written submission from GEC., namely IR 22, IR 31 and IR 118c.

<u>IR 53 a, b and c</u> GEC requested information on the demand elasticity inputs used in its load forecasts. The OPA responded there are no demand elasticities built into the model.

The Board believes that the OPA's responses are sufficient at this time and may be clarified under cross-examination.

<u>IR 61, 62 and 63</u> GEC sought information on how storage was valued in the various IPSP models and information on the value of any ancillary service which could provide such storage. In addition GEC sought the OPA's best estimate of the value of some specific storage capacities posed by GEC.

The OPA replied that storage was a capacity resource. Mr Vegh indicated that it was not proposed in the Plan because storage attributes were insufficient to warrant inclusion.

The Board finds that the topic of storage is relevant to the proceeding. However, the Board infers from the OPA's response to interrogatory 64 that the OPA has no further information or analysis on storage. Therefore the Board considers the OPA's response to be complete. The Board expects that this topic will be further addressed through intervenor evidence and cross-examination.

<u>IR 90 and IR 110</u> GEC asked for a significant amount of information regarding the nuclear technologies under consideration for Ontario's new nuclear projects. GEC said

that it sought this information to be able to test the variability in the Plan and its resilience depending on the technology chosen. The OPA submitted that analysis of the various nuclear technologies is out of scope because the issue of the choice of nuclear technology was ruled to be out of scope in the Board's Issues Decision.

While, the matter of the resilience of the IPSP is certainly within the scope of the proceeding, the breadth of information requested by GEC in these interrogatories is more than required by the Board for this purpose. Therefore, the Board does not require the OPA to respond to these interrogatories. However, the Board would be better informed if it had an understanding of the range of capacity factors possible given the technologies being considered for new nuclear resources. The Board therefore orders the OPA to provide this information, or if it is unable to do so, to explain why. The Board notes that it does not require information that is specific for each technology.

<u>IR 178</u> GEC, through its Motion, sought the OPA's comments on whether the plans that resulted from the various model runs performed for GEC could be implemented, and in particular, Mr. Poch highlighted the results of Model Run 3, the High Nuclear Costs scenario. The OPA responded that these results are not detailed plans supported by careful assessment by the OPA of the implementation requirements. They are just the results of running the models with various assumptions put forward by the intervenors to test the implications of the different assumptions. The OPA is therefore not able to respond to the request.

The High Nuclear Cost scenario is relevant to the proceeding. However, the Board expects that the issue of implementation can be addressed during cross-examination and does not order the production of further information at this time.

<u>IR 197a, and IR198a</u> GEC requested background reports and studies to explain the basis for the OPA's selection of the form and parameters for the probability distribution it had used in its models for conservation additions and renewable supply additions risk. Mr. Vegh stated that the response was complete and that clarification could be sought during cross examination.

The Board agrees with the OPA that its response is complete and therefore will make no further direction on this matter.

<u>IR 205</u> GEC requested the inputs and outputs of the Monte Carlo model used to generate probability distributions on existing nuclear plant performance. GEC noted that

the OPA had provided this information in part but had redacted the information for the 2009 to 2014 time period on the grounds of confidentiality. Mr. Vegh responded that in the absence of a Board order, the OPA was not in a position to release this information under the confidentiality agreements it has in place with OPG and Bruce Nuclear Power.

The Board believes this information to be of relevance to the hearing and directs the OPA to produce it. The Board accepts the OPA's submissions that this information should be granted confidential status, and therefore it will only be made available to parties that sign the Board's confidentiality Undertaking (which is found at Appendix D of the Board's Practice Direction on Confidential Filings).

<u>IR 212</u> GEC requested information on all capacity retirement dates. GEC stated that retirement dates had only been provided for Non-Utility Generation ("NUGs") and the dates were end of contract dates and not end of life dates. GEC Counsel noted that the OPA had provided an updated response but that it was still seeking clarification of the interpretation of these dates. Mr. Poch also asked for unit-specific retirement dates for the existing nuclear plants which the OPA refused to provide on the grounds of confidentiality.

Regarding further information on retirement of NUGs, the Board is satisfied that information provided is sufficient and regards contract expiry as a reasonable proxy for retirement date. Regarding the retirement of existing nuclear plants, the Board finds that unit retirement dates are relevant information that will be helpful to the Board and orders its production, or, if it is unable to do so, explain why. The Board accepts the OPA's submissions that information relating to the retirement dates of existing nuclear plants should be granted confidential status, and therefore this information will only be made available to parties that sign the Board's confidentiality Undertaking.

<u>IR 221 d</u> GEC asked the question "is increased reliance on interconnections to retire coal plants feasible and at what cost". The OPA responded that the response was complete and contained reasons as to why increased reliance on interconnections was not appropriate for this purpose. GEC counsel in his reply submission stated that all OPA had done was state that contracts were necessary and that answer was not sufficient.

The Board believes the OPA’s response to be complete and therefore will provide no further direction on this matter.

The City of Thunder Bay, the Northwestern Ontario Municipal Association and the Town of Atikokan

NOMA brought a motion seeking further and better answers to NOMA interrogatories 1 and 2. In addition, NOMA sought the production of documents from the OPA, the Independent Electricity System Operator (“IESO”) and Hydro One Networks Inc.

The first part of the motion, seeking better answers to interrogatories 1 and 2, proposed questions relating to a comparison of environmental impacts, particularly emissions, and costs between coal fired generators, existing gas fired generators, and planned gas-fired generation in the northwest. The “planned generation” refers to the potential for the conversion of the Thunder Bay Generating Station to gas-fired generation, which appeared in the results of a modelling run undertaken by the OPA at the request of NOMA and containing assumptions proposed by NOMA.

The second part of the motion sought an order for the production of documents from the OPA, the IESO and Hydro One as follows:

- The IESO System Control Order for the 10 electrical zones in Ontario; and
- All documents, including without limitation, analyses, reports and professional opinions relating to inertia.

Counsel for NOMA, Mr. Melchiorre, argued that both types of requests flowed directly from the interrogatory responses, and were also grounded in the wording of the Supply Mix Directive, Regulation 424/04 and the Board’s Issues List for the proceeding. Mr. Melchiorre also argued that even if the Board found that the requests for information did constitute a second round of interrogatories, procedural fairness would dictate that NOMA should be permitted an opportunity to ask interrogatories regarding the potential for the conversion of the Thunder Bay Generating Station to gas-fired generation, as this possibility was first mentioned in a model run delivered to NOMA at the same time as the responses to the interrogatories.

With respect to the requests for production of documents, Mr. Melchiorre argued that the documents would assist parties and the Board in approaching several issues on the Issues List, particularly issue 34, which deals with system reliability in all regions of

Ontario. The Board has the power, it was submitted, to order such production under its own Rules of Practice and Procedure or under the Statutory Powers Procedure Act.

Mr. Vegh, for the OPA, submitted that the requests by NOMA were properly characterized not as a request for further and better answers to interrogatories, but as a request for a second round of interrogatories, or an extension of time to file interrogatories. It would not be fair, Mr. Vegh argued, to give just one party an opportunity to ask a second round of interrogatories. With regard to the questions arising from the possibility of the conversion of the generating station to gas, Mr. Vegh pointed out that there is no such proposal in the IPSP, and the suggestion arose only from a model run whose assumptions were dictated by NOMA. The OPA is not proposing such a conversion now, and Mr. Vegh submitted that if such a proposal were to come forward, all parties would have an opportunity to ask questions about it. Lastly, Mr. Vegh argued that if the Board were to consider the substance of the motion for the production of documents from the IESO and Hydro One; that those third parties should be given the opportunity to make submissions on whether the documents that are in their possession should be produced.

The Board agrees with Mr. Vegh that the questions now being posed by NOMA are not requests for better answers to interrogatories already asked by NOMA. The questions are different. However, this fact is not necessarily determinative of the matter. The Board has the power under the *Ontario Energy Board Act, 1998* section 21(1) to give directions or require the preparation of evidence at any time when it is exercising the powers conferred on it. If the Board found that certain information from the OPA was necessary for it to fulfil its mandate to review the IPSP, it could order such information to be produced. In doing so, the Board would have to have regard to procedural fairness, and, in this case, to the critical importance of the hearing schedule.

The Board finds that it does not require the answers to the questions posed in the first part of NOMA's motion. The answers provided by the OPA to the NOMA interrogatories, particularly when read together, are sufficiently complete and responsive. On the question of the opportunity to ask interrogatories about the possibility of a conversion of the Thunder Bay Generating Station to gas, the Board does not expect the OPA to have detailed information on this topic since such a conversion is not proposed in the IPSP. NOMA may choose to produce evidence itself or cross-examine on this topic.

Similarly, the Board will not order the production of documents as requested in the second part of the NOMA motion. NOMA argued that the request for production of the IESO system control orders flows directly from the OPA's response to NOMA's interrogatory 1a.(Is the Northwest an electricity system island?) and that the system control orders will show that the Northwest is an electricity system island. The Board finds that OPA's response to 1a) to be responsive and complete. The response provides both a clear answer and rationale in support of the answer and the Board is satisfied that it does not require more information at this time. The Board agrees with NOMA's assertion that this matter is relevant to issue 34 of the issues list regarding reliability. NOMA will have the opportunity to challenge the OPA's response during the oral phase of this proceeding.

NOMA also requested the production of documents originating from OPA, IESO and Hydro One relating to inertia in the Northwest. NOMA argued that the request flows appropriately and directly from the OPA's responses to interrogatories number 5 c), d) and e) and in particular the OPA's inclusion of a reference to model runs in these responses. NOMA submitted that these interrogatories dealt with inertia issues and were within the scope of issue number 34 on reliability as well as issue numbers 20, 21 and 33 pertaining to the cessation of the use of coal as well as safety and environmental protection.

As stated above the OPA argued that the request should be denied because the IPSP does not contain a planned conversion to gas-fired generation.

The Board does not consider it necessary to grant the request to order production of reports pertaining to inertia. The OPA has been clear about its planning activities pertaining to generation resource options pre and post the cessation of the use of coal fired generation and has been explicit regarding their views pertaining to the effect of the shutting down of the coal-generation plants by 2014. This iteration of the IPSP does not contain firm generation plans for the Northwest beyond 2014 and it does not deal with the inertia issues that may arise in that time frame. NOMA may provide evidence, cross-examine and make arguments on the appropriateness of this aspect of the Plan. However, the Board is of the view that in order to conduct an effective and efficient hearing, the degree of probing of the various elements of the IPSP must be commensurate with the degree to which the IPSP is reliant on those elements for its success.

Xylene Power

Dr. Charles Rhodes, on behalf of Xylene Power, brought a motion seeking further and better answers to a large number interrogatories that the OPA had refused to answer on various grounds, or had, in Mr. Rhodes submission, answered inadequately. Dr. Rhodes, in his oral submissions, argued that the interrogatories were relevant to the proceeding, as he wished to demonstrate in the hearing that the IPSP is inadequate with respect to several factors, including overuse of fossil fuels, lack of planned energy storage and failure to quantitatively consider the severe consequences of global warming.

Dr. Rhodes argued that answers to these interrogatories are required to demonstrate serious failings in the IPSP that will have grave environmental effects. In particular, he argued that the emphasis in the IPSP on fossil fuel generation is short sighted and ignores the human and environmental catastrophes that will result from global warming.

Mr. Vegh argued in response that the majority of the interrogatories asked by Xylene Power did not serve the purposes required of interrogatories in the Board's Rules of Practice and Procedure; they did not clarify the application, simplify the issues, improve understanding of the issues or expedite the proceeding. The questions, he argued, were not relevant to the IPSP as filed. Mr. Vegh recognized that Dr. Rhodes has a very different perspective on the issues from that of the OPA, but suggested that there is sufficient information on the record as it stands for Dr. Rhodes to make his arguments criticizing the IPSP. In addition, Dr. Rhodes can bring forward the articles he seeks in several of the interrogatories as evidence filed by Xylene Power.

The Board agrees with Mr. Vegh that many of the interrogatories posed by Xylene Power do not comply with the purposes for interrogatories set out in Rule 28.01 of the Board's Rules. Many of the disputed questions asked the OPA to provide detailed information that would not be helpful to the elucidation of the IPSP, or the Board's mandate in reviewing the Plan. Dr. Rhodes can bring forward his criticisms of the Plan without a need for the detailed information he sought from the OPA.

The interrogatories of Xylene Power were directed at issue A11, which is:

> "What is the base-load requirement after the contribution of existing and committed projects and planned conservation and renewable supply?"

However in the motion record and in his oral remarks, Dr. Rhodes also indicated that his interrogatory questions related to Issues A31 and A32 (Environmental Issues in Developing the IPSP).

It is not part of this Board's mandate to recalculate the base load requirement in the Plan. It is part of the Board's mandate to test the Plan for its robustness in the face of change. The Board believes many of the issues raised by Dr. Rhodes for Xylene Power would more properly be considered under issue A33, which reads:

> "Do the forecasts relied upon by the OPA in developing the IPSP, and the uncertainties attributed to them, present a reasonable range of future outcomes for planning purposes?"

The Board's Issues Decision, at page 11, describes the scope of this issue:

> "The Board agrees that its responsibility in this proceeding does not extend to approving the demand forecast and reserve requirement. However, it is important, in the context of examining how the planners developing the IPSP used the forecast, to query the main assumptions in the forecast and how the Plan will change or adapt in response to variations from that forecast."

The Board will not require the OPA to provide further answers to the interrogatories posed by Xylene Power. The Board did, however, find the submissions of Dr. Rhodes insightful, and believes that his perspective on issues in this proceeding will continue to be of value to the Board. The Board would be assisted in having more information on several of the topics raised by Xylene Power's interrogatories and Motion, to be considered as part of issues A11 and A33. Therefore, the Board will require the OPA to file with the Board, and copy to all intervenors, the answers to the following questions:

1. Did the OPA give consideration to the following areas when assembling the IPSP:

   - A large scale energy conversion of natural gas/oil heating systems to electrical grid power;
   - A large scale energy conversion of gas/diesel transportation vehicles to batteries charged by electrical grid power; and
   - Significantly more storage capability such as pumped hydraulic storage to assist wind and solar?

If these factors were considered, how did each of them affect the Plan and the Plan outputs? What accommodations had to be made to the Plan as a result? If these factors were not considered, please explain in detail why not.

2. Describe how the OPA will monitor societal and technological developments relevant to energy system planning. Please describe how such changes as those mentioned in question 1, should they arise, will be incorporated into future iterations of the IPSP.

Summary of Board Requirements on Motions on Interrogatory Responses

NCO

1) The Board orders the OPA to provide an answer which identifies all projects within the IPSP that affect or may affect First Nations Reserve and Treaty Lands. This listing should include any projects on which work is done or money committed or for which development is expected to occur during the following three time frames:

- 2007 and 2010
- 2010 and 2013
- beyond 2013.

The listing should be divided by these time fames

GEC

Models, spreadsheets and work papers

The Board orders as follows:

2) The OPA shall provide to GEC copies of the Reserve and Insurance Calculator, the Capacity Planning Tool and the Profile Generator for Wind.

3) The OPA shall provide GEC with the assumptions, inputs and outputs from the three models provided.

4) The OPA shall provide to GEC's experts the opportunity to attend at the OPA's offices, to join with OPA staff in completing one or more model runs employing assumptions and inputs as selected by GEC. The intention is to have the GEC representatives be able to observe all phases of these model runs so that they can better understand such matters as, for example: how the data input is carried out; how the general logic structure and the model connectivity perform; and if there are any embedded decision-making rules or trade-offs employed that they are unaware of. This opportunity should be time-limited to no more than three business days. A Board staff representative will be in attendance.

5) GEC shall file all assumptions, inputs and outputs from the model runs on the public record.

6) GEC's counsel and experts, and any party that has access to confidential information as a result of this order of the Board, shall enter into a confidentiality agreement in the form specified in the Board's Rules of Practice and Procedure.

<u>Specific interrogatories</u>

7) The Board orders that answers to the following GEC interrogatories be provided by the OPA:

   a) GEC interrogatory 46b concerning transmission investments for the Planned period;
   b) GEC interrogatory 205 concerning the inputs and outputs of the Monte Carlo Model used to generate probability distributions on existing nuclear plant performance. GEC's counsel and experts, and any party that wishes to have access to information deemed confidential by the Board in this decision, must first sign the Board's confidentiality Undertaking;
   c) GEC interrogatory 210 concerning inputs for a probability distribution for resources at risk in the Plan for the year 2016; and
   d) GEC interrogatory 212 concerning unit retirement dates of existing nuclear plants.

8) GEC's counsel and experts, and any party that wishes to have access to information deemed confidential by the Board in this decision, must first sign the Board's confidentiality Undertaking.

The Board also orders the OPA to file with the Board and copy to all intervenors the answer to the following question:

9) What range of capacity factors are expected for the technologies being considered for new nuclear resources in Ontario? If the OPA is unable to provide this information, please explain why. The Board notes that it does not require information that is specific for each technology.

Xylene

The Board orders the OPA to file with the Board and copy to all intervenors answers to the following questions:

10) Did the OPA give consideration to the following areas when assembling the IPSP:

   a) A large scale energy conversion of natural gas/oil heating systems to electrical grid power;
   b) A large scale energy conversion of gas/diesel transportation vehicles to batteries charged by electrical grid power; and
   c) Significantly more storage capability such as pumped hydraulic storage to assist wind and solar?

   If these factors were considered, how did each of them affect the Plan and the Plan outputs? What accommodations had to be made to the Plan as a result? If these factors were not considered, please explain in detail why not.

11) Please describe how the OPA will monitor societal and technological developments relevant to energy system planning. Please describe how such changes as those mentioned in question 10, should they arise, will be incorporated into future iterations of the IPSP.

DATED at Toronto, July 29, 2008
ONTARIO ENERGY BOARD

Original signed by
Kirsten Walli
Board Secretary

EB-2005-0520

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 Union Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2007.

BEFORE: Pamela Nowina
Presiding Member

Paul Sommerville
Member

Ken Quesnelle
Member

DECISION AND ORDER

Union Gas Limited ("Union" or the "Company") filed an Application, dated December 15, 2005, with the Ontario Energy Board under section 36 of the *Ontario Energy Board Act, S.O. 1998*, c.15, Schedule B. The Board has assigned file number EB-2005-0520 to the Application. The Board held an Issues Day proceeding and has established an Issues List for the case.

The Board received correspondence from Mr. Crockford on May 5, 2006, which included a further interim claim for costs, a request to participate in the pending hearing by way of teleconferencing, and a request for a Board Order requiring the Applicant, Union, to provide further answers to the interrogatories filed by Mr. Crockford.

The Board will deal with the first two aspects raised in Mr. Crockford's letter separately.

This Decision and Order will address only Mr. Crockford's request for further interrogatory responses.

While Mr. Crockford's correspondence did not take the form of a Motion, the Board considers it to be such. He explicitly requests that the Board issue an Order to Union to require it to provide "proper responses" to the list of Interrogatories contained in his letter.

The Board has provided a copy of Mr. Crockford's letter to Union. For the reasons contained herein, the Board does not need to consider any response which Union may wish to make.

Rules 28 and 29 inform the Board's process with respect to the Interrogatories.

Rule 28 establishes that the purpose of Interrogatories is to clarify evidence, simplify the issues, expedite the proceeding and to permit a full understanding of the matters in issue in the proceeding.

Rule 29 sets out the requirements for responses, and provides for a refusal to answer in circumstances where the requested response cannot be provided with reasonable effort, or where the question is considered to be not relevant to the issues established in the case.

Mr. Crockford's request is denied in its entirety. The Board has carefully reviewed the responses to the Interrogatories which Mr. Crockford considers to be deficient and finds that no further responses are warranted or necessary for the effective conduct of the proceeding.

Mr. Crockford has organized his complaints into two categories: one which addresses responses to Interrogatories respecting the Winter Warmth Program; and a second category that deals with interrogatory responses to all other subject matters.

It is clear that the Winter Warmth Program is of special interest to Mr. Crockford. He was denied enrolment in the program by the program administrator in Sudbury, the Canadian Red Cross.

With respect, that decision cannot be redressed in this proceeding, which is directed solely to the establishment of rates for the delivery of gas in Union's franchise area. Mr.

Crockford's remedy for being denied enrollment in the program, if there is one, lies with the administrator of the program in Sudbury.

The Board has carefully considered Union's responses in the area of the Winter Warmth Program and finds them to have been appropriate and reasonable, given the fact that Union does not itself manage the program. Further, it is clear to the Board that Mr. Crockford's claim for "proper responses" is really based on a desire to ask additional questions. The Board's process does not and cannot accommodate a multi-staged interrogatory process in this proceeding. A person wishing to submit interrogatories is entitled to reasonable responses to them, but not to a series of new questions. This is especially so when the supplementary questions concern an issue which is tangential to the determination of delivery rates.

With respect to Union's responses on other subject matters, the Board notes that in a number of cases, Mr. Crockford is dissatisfied with Union's tendency to merely refer to Board Decisions, or Orders, rather than providing copies of them. The Board will not order Union to provide copies of such Decisions and Orders, on the basis that to do so would involve the distribution of very considerable volumes of paper, when they can be easily accessed through the Board's offices and its website.

Another category of responses which Mr. Crockford considers to be unsatisfactory are those where Union has indicated that it does not organize its costs and revenue data according to operating area, and therefore cannot provide responses to certain questions on that basis. In the Board's view, the Union responses are sufficient in light of Rule 29.02(b) which provides for a refusal to provide responses in circumstances where the development of the answer cannot be achieved without unreasonable effort. Applicants cannot be expected to completely reorganize their accounts simply to accommodate an interrogatory without a very compelling argument rooted in the Issues List and supported with more than a mere desire to see the data represented in a certain fashion. Mr. Crockford provided no such rationale in his request for further responses.

Mr. Crockford's requests in this area also seem to be little more than a desire to ask additional questions. For example, with respect to Union's response to Interrogatory J31.30, Mr. Crockford introduces his request for a proper answer with the words "Given the evidence provided please explain why customers are paying the same 14$ monthly fee […]" This is clearly a supplementary question, not a request for a proper response to an interrogatory which has been inadequately answered. The same element is present in Mr. Crockford's complaint about answers to Interrogatories 31.24, 25, 26, 27, 28, 29, 34, 35, 49, 57, 58, 62, 68 and 70.

The remaining complaints appear to reject Union's practice of using one answer to cover numerous Interrogatories. The Board considers this practice to be appropriate and reasonable in the circumstances, where the referenced answer is responsive to the interrogatories to which it is applied.

Finally, the Board considers that the additional information sought by Mr. Crockford in his request would not be of material assistance to the Board in its consideration of Union's delivery rates for 2007, which is the fundamental and overriding purpose of the proceeding.

In the circumstances, the Board will make no order as to costs with respect to Mr. Crockford's request.

THE BOARD THEREFORE ORDERS THAT:

1. Mr. Crockford's request for a Board Order respecting Union Gas Limited's interrogatory responses is denied.

DATED at Toronto, May 11, 2006

ONTARIO ENERGY BOARD

Peter H. O'Dell
Assistant Board Secretary

Case Name:

Intel Corp. v. 3395383 Canada Inc.

Between
Intel Corporation, plaintiff, and
3395383 Canada Inc. and 9047-9320 Québec Inc.,
defendants

[2004] F.C.J. No. 251

[2004] A.C.F. no 251

2004 FC 218

2004 CF 218

30 C.P.R. (4th) 469

129 A.C.W.S. (3d) 55

Docket T-1993-01

Federal Court
Toronto, Ontario

Heneghan J.

Heard: August 11, 2003.
Judgment: February 11, 2004.

(34 paras.)

Counsel:

Brian Isaac and Mark Biernacki, for the plaintiff.
Alexandra Steele, for the defendants.

REASONS FOR ORDER AND ORDER

HENEGHAN J.:--

INTRODUCTION

1 Intel Corporation (the "Plaintiff") appeals from the order of Prothonotary Morneau dated July 18, 2003, relating to the refusal by the Prothonotary to order the Defendant 3395383 Canada Inc. ("Canada Inc.") to answer certain questions set out in categories (a) and (b), except question 242, as set out in Appendix "A" to the Plaintiff's original notice of motion dated July 8, 2003.

FACTS

2 The Plaintiff commenced this action on November 7, 2001, alleging unlawful use by Canada Inc. and 9047-9320 Quebec Inc. ("Quebec Inc.") of certain trademarks owned by the Plaintiff, thereby causing damage to the Plaintiff. The Plaintiff raised issues of infringement and confusion in its statement of claim; these allegations were denied by Canada Inc. and accordingly, remain unadmitted allegations of fact.

3 The Plaintiff commenced its action against both Canada Inc. and Quebec Inc., but Quebec Inc. has since been dissolved pursuant to the applicable provisions of the laws of the Province of Quebec. For practical purposes, Canada Inc. is the only Defendant in this action.

4 The Plaintiff undertook discovery examination of Mr. Michael Cuplowsky, as the representative of Canada Inc., on October 2, 2002. In the course of that examination, refusals were entered to certain questions asked on behalf of the Plaintiff. The original notice of motion before the Prothonotary, that is the notice of motion dated July 8, 2003, classified the outstanding refusals under three headings. The first, category "a", related to questions about the identification of Canada Inc.'s suppliers and customers. Questions 242, 245, 526 and 810 were in this group.

5 Category "b" dealt with questions about email communications to Canada Inc. at the pentiumconstruction.com website which was in operation from October 1999. Category "c" covered one question which is not the subject of this appeal.

6 The Prothonotary determined that questions 242 and 245 need not be answered since they showed an attempt by the Plaintiff to obtain information from the Defendant Canada Inc. about persons who might have been involved with the Defendant Quebec Inc. and who might have knowledge of the activities of that now dissolved corporate entity. He also found that question 245 was improper as being in the nature of a "fishing expedition". Questions 242 and 245 are as follows:

> 242 Make inquiries of Mr. Kotler to see if he can provide documents pertaining to suppliers of materials of the model home built by Quebec Inc.
>
> 245 Identify all of the subcontractors that were utilized in respect of the model home built by Quebec Inc.

7 The Prothonotary upheld the refusal of Mr. Cuplowsky to answer the remaining questions in category (a) and (b), on the basis that these remaining questions were not relevant and were in the nature of a "fishing expedition", for the purpose of assisting the Plaintiff to establish its allegations of confusion or damage to its reputation. These questions are as follows

> 526 Produce a copy of each offer for purchase and sale in respect of each house sold by Canada Inc.

526 Produce a list of names and, to the best of the Defendant's knowledge, current location of each of the customers whom the Canada Inc. company has sold a house to.

810 Produce a list of suppliers and subcontractors to Canada Inc. with contact information

812 Produce a copy of every e-mail received at the e-mail address sales

sales@pentiumconstruction.com

813 Search the archived files and deleted directory and produce any additional e-mails that have been received at sales@pentiumconstruction.com

814 Agree to an undertaking to produce all e-mails received in the future at sales@pentiumconstruction.com.

SUBMISSIONS

8 The Plaintiff argues that the Prothonotary was clearly wrong and that he erred in fact and in principle in making his decision. The Plaintiff says that the Prothonotary misapprehended the facts with respect to question 245, concerning the identity of all subcontractors that were engaged to build a model home for Quebec Inc., and consequently, erred in upholding the refusal.

9 As well, the Plaintiff argues that the Prothonotary erred in principle relative to question 245, by improperly finding it irrelevant and in the nature of a "fishing expedition". The Plaintiff says that the question arises from unadmitted allegations of facts in the pleadings and as such, it is relevant. It submits that it is a proper question and does not amount to an attempt to advance a cause of action that is not raised in the pleadings. The Plaintiff here relies on paragraphs 21 to 24 of its statement of claim, paragraph 12 of the amended defence and paragraph 6 of its amended reply.

10 The Plaintiff also argues that the Prothonotary erred in principle in upholding the Defendant's refusal to answer the remaining questions in category (a) and the refusal to answer all of the questions in category (b). Again, the Plaintiff says that these questions are relevant to the allegations made in the statement of claim that are denied by the Defendant and the Prothonotary erred in finding otherwise.

11 The Plaintiff argues that the Prothonotary erred in his application of the principle against using the discovery process as a "fishing expedition" and submits that it is entitled to ask questions of the Defendant's representative in order to elicit information that is relevant to its statement of claim. Specifically, the Plaintiff says that it has raised the issues of confusion and depreciation of goodwill in its statement of claim. Relying on Wonder Bakeries Ltd. v. Max Furman et al. (1958), 29 C.P.R. 154 (Ex. Ct.) and Superseal Corp. v. Glaverbel-Mecaniva Canada Limited (1975), 20 C.P.R. (2d) 77 (F.C.T.D.), rev'd (1975), 26 C.P.R. (2d) 140 (F.C.A.), the Plaintiff says it is entitled to rely on facts not within its knowledge to support a cause of action. It submits that its questions about the awareness of actual confusion or injury to its reputation depend upon knowing the identities of the persons who were exposed to the Defendant's trade-mark or trade name. It says that it has asked proper questions which should be answered.

12 The Plaintiff argues that its request for access to emails sent to the Defendant is proper because it is relevant. It says that there is no evidence of difficulty or impossibility on the part of the Defendant in providing this information. The Plaintiff argues that there is no evidence to support the Prothonotary's finding that contact by the Plaintiff with suppliers, customers and subcontractors "might lead to strain, and even disruption" of the Defendant's business, and says this statement is based on speculation. In making this finding, the Prothonotary has interfered with the Plaintiff's right to pursue relevant inquiries in an expeditious manner.

13 The Defendant argues, in reply, that the Plaintiff has no right to ask questions of its representatives about Quebec Inc. That corporate entity no longer exists and the Defendant is under no obligation to pursue lines of inquiry relative to it.

14 The Defendant further submits that the Plaintiff has failed to show that the Prothonotary erred in fact or in law in his decision. Rather, the Plaintiff is expressing a difference of opinion and that is insufficient to meet the test for reversing the Prothonotary's decision. The Defendant here relies on Anchor Brewing Co. v. Sleeman Brewing and Malting Co. (2001), 15 C.P.R. (4th) 63 (F.C.T.D.) and Hayden Manufacturing Co. v. Canplas Industries Ltd. (1998), 86 C.P.R. (3d) 17 (F.C.T.D.).

15 The Defendant says that the questions in issue were properly characterized by the Prothonotary as being in the nature of a "fishing expedition". These questions are not relevant to the action and in any event, are too broad.

16 Further, the Prothonotary did have evidence before him to support his finding about the potential negative impact on the Defendant's business activities, if the Plaintiff were allowed to question the Defendant's customers and suppliers about confusion resulting from exposure to the Defendant's trade-names. The Defendant here refers to the affidavit of Mr. Cuplowsky that was before the Prothonotary. The Plaintiff did not cross-examine Mr. Cuplowsky.

17 The Defendant argues that the Plaintiff has failed to show that the decision of the Prothonotary is "clearly wrong" and that this appeal should be dismissed.

ANALYSIS

18 This is an appeal from the Order of Prothonotary Morneau upon the Plaintiff's motion arising from the refusal of the Defendant representative to answer certain questions during his discovery examination. Generally an order involving the responses to questions at discovery is considered to be a discretionary order: see James River Corp. of Virginia v. Hallmark Cards Inc. (1997), 72 C.P.R. (3d) 157 (F.C.T.D.). According to Canada v. Aqua-Gem Investments Ltd., [1993] 2 F.C. 425 (C.A.), a decision of a prothonotary will remain undisturbed on appeal unless it is clearly wrong in the sense that the exercise of discretion was based on a wrong principle of law or misapprehension of the facts or where the order raises a question vital to the final disposition of the case. The latter does not apply here, so the question is whether the Prothonotary clearly erred in fact or in principle in upholding the refusals.

19 The discovery examination process is governed by the Federal Court Rules, 1998, SOR/98-106, (the "Rules") Rules 237 to 248. Rule 240 sets forth the general principle that questions on discovery can be directed to matters that are relevant to any unadmitted allegation or fact raised in a pleading. Rule 240 provides as follows:

240. Scope of examination - A person being examined for discovery shall answer, to the best of the person's knowledge, information and belief, any question that

(a) is relevant to any unadmitted allegation of fact in a pleading filed by the party being examined or by the examining party; or
(b) concerns the name or address of any person, other than an expert witness, who might reasonably be expected to have knowledge relating to a matter in question in the action.

* * *

Étendue de l'interrogatoire - La personne soumise à un interrogatoire préalable répond, au mieux de sa connaissance et de sa croyance, à toute question qui:

a) soit se rapporte à un fait allégué et non admis dans un acte de procédure déposé par la partie soumise à l'interrogatoire préalable ou par la partie qui interroge;
b) soit concerne le nom ou l'adresse d'une personne, autre qu'un témoin expert, don't il est raisonnable de croire qu'elle a une connaissance d'une question en litige dans l'action.

20 In his reasons, the Prothonotary reviewed the meaning of relevance in the context of discovery and its application to the issues in this action, that is the alleged infringement of the Plaintiff's trademark, together with allegations of confusion and depreciation of goodwill. He considered relevance, in terms of the breadth of the questions other than question 245 and concluded that those remaining questions were not relevant to the matters in issue and in any event, were too broad. In making his order, the Prothonotary considered and applied the principle against using the discovery process as a "fishing expedition".

21 The Prothonotary upheld the refusal to answer question 245 on the basis that this related to a corporate entity that is independent of the Defendant Canada Inc. Relying on Rule 241, he found that Canada Inc. was not obliged to make inquiries of another party who might have knowledge of the matters in issue in the action. I see no error of fact or in principle with this conclusion.

22 The Prothonotary maintained the Defendant's refusal to answer the remaining questions on the grounds that they represented an improper attempt by the Plaintiff to use the discovery process as a "fishing expedition" to obtain information to bolster its case.

23 The prohibition against using the discovery process in this way has been discussed in a number of cases including Burnaby Machine & Mill Equipment Ltd. v. Berglund Industrial Supply Co. Ltd. et al. (1984), 81 C.P.R. (2d) 251 (F.C.T.D.) and Crestbrook Forest Industries Ltd. v. Canada, [1993] 3 F.C. 251 (C.A.). In Burnaby, supra, the Court said as follows at pages 254-255:

> In argument reference was made to the general tendency of the courts to grant broad discovery. ...
>
> ...

> This must be balanced against the tendency, particularly in industrial property cases, of parties to attempt to engage in fishing expeditions which should not be encouraged. A recent example of this principle is found in the case of Monarch Marking Systems, Inc. et al. v. Esselte Meto Ltd. et al. (1983), 75 C.P.R. (2d) 130 at p. 133, in which Mahoney J. stated:
>
>> I accept the definition of a "fishing expedition", in the context of discovery, as given by Lord Esher M.R. in Hennessy v. Wright (No. 2) (1980), 24 Q.B.D. 445 at p. 448, a libel action:
>>
>>> "... the plaintiff wishes to maintain his questions, and to insist upon answers to them, in order that he may find out something of which he knows nothing now, which might enable him to make a case of which he has no knowledge at present".
>>
>> I agree with the defendants. Notwithstanding the present state of the pleadings and that Rule 465(15), taken literally, is broad enough to encompass the questions of category 1, those questions are, in substance, a fishing expedition. They need not be answered.

24 Are the remaining questions relevant to the issues raised in this proceeding? The Plaintiff says they are, in light of the pleadings. Paragraphs 21 to 24 of the Statement of Claim, paragraph 12 of the Amended Defence, paragraph 22 of the Counterclaim and paragraph 6 of the Amended Reply provide as follows:

> Statement of Claim
>
> 21. The Defendants' unauthorized use of the trade-mark PENTIUM as aforesaid has caused and is likely to cause confusion with the Plaintiff's registered PENTIUM trade-mark, in that such use has led and is likely to lead to the inference that the Defendants [sic] services are provided, offered, advertised, or approved by the Plaintiff
> 22. By their conduct and actions as aforesaid, the Defendants have infringed, and are deemed to have infringed the rights of the Plaintiff in trade-mark registration nos. TMA428,593 and TMA534,128, contrary to section 20 of the Trade-marks Act.
> 23. By their conduct and actions as aforesaid, the Defendants have used the trade-mark that is the subject of registration nos. TMA428,593 and TMA534,128 in a manner that is likely to have the effect of depreciating the value of the goodwill attaching thereto, contrary to section 22 of the Trade-marks Act.
> 24. By their conduct and actions as aforesaid, the Defendants have directed public attention to their services and business in such a way as to cause or to be likely to cause confusion in Canada, at the time they commenced to do so, and thereafter, between their services and business and the wares, services and business of the Plaintiff, contrary to section 7(b) of the Trade-marks Act.
>
> Amended Defence and Counterclaim

12. The Defendant denies paragraphs 21, 22, 23 and 24 of the Statement of Claim.
22. The PENTIUM trade-mark registration No TMA534128 is invalid, void and of no effect for the following reasons:

a) The Plaintiff has abandoned the use of the PENTIUM trade-mark in Canada (section 18(1)(a) of the Trade-Marks Act) in association with precious metals and their alloys; jewellery, precious stones; clocks, bracelets, jewellrey, [sic] necklace charms, bracelet charms, and earring charms, cuff links, earrings, key chains, necklaces, necktie fasteners, lapel pins, money clips, necklace pendants, bracelet pendants, and earring pendants, piggy banks, tie pins, tie slides, trophies and watches; cardboard; photographs, adhesives for stationery or household purposes; playing cards, printers' type; binders; bookends, bookmarkers, boxes for pens, calendars, tablets, cards, pads, pens, pencils, folders, paperweights, pen and pencil holders, photograph stands, rulers, erasers, markers, desk sets, and bumper stickers, leather and imitations of leather; animal skins, hides; trunks and travelling bags, umbrellas, travel bags, luggage, school bags, back packs, beach bags, duffel bags, fanny packs, and umbrellas; steelwool; unworked or semi-worked glass (except glass used in building); earthenware (not included in other classes); mugs and sports bottles; t-shirts, shirts, tank tops, boxer shorts, leather jackets, sweaters, sweatshirts, sweat suits, coveralls, jackets, pants, shorts, ties, bandannas, headwear, namely baseball caps and night caps, bow ties, cardigans, gloves, gym suits, hats, jackets, jogging suits, neckties, polo shirts, scarves, infant rompers, smocks, socks and visors; sporting goods, namely footballs; decorations for Christmas trees; objects for children to play with, namely stuffed toys, plush toys, puppets, dolls, bean bags, board games, video games; and seasonal ornamentation, namely Christmas tree ornaments. The Plaintiff's use of the trade-mark in association with the above wares (if any) was only a token use to allow the filing of a declaration of use, and the plaintiff [sic] has since then, not used the trade-mark in association with all of the said wares in the normal course of trade. From such non use in the normal course of trade for a long period can be inferred the intention to abandon the trade-mark.
b) The Plaintiff was not the person entitled to secure the registration (section 18(1) in fine, section 16(3) and section 40(2) of the Trade-mars [sic] Act) since it never used the trade-mark in Canada in association with the wares specified in the application, the whole contrary to what was stated in the declaration of use which was filed by the Plaintiff. If any use was ever made, it was not as a trade-mark (section 4 of the Trade-Marks Act) but as publicity devices for the promotion of its own microprocessors.
c) The trade-mark is not distinctive at the time the proceedings bringing the validity of the registration into question are commenced (section 18(1)(b) of the Trade-Marks Act) since the Plaintiff has not exercised under licence, direct or indirect control (section 50(1) of the Trade-Marks Act) over the character or quality of the wares in association with which the PENTIUM trade-mark was allegedly used, namely: precious metals and their alloys;

jewellery, precious stones; clocks, bracelets, jewellrey, [sic] necklace charms, bracelet charms, and earring charms, cuff links, earrings, key chains, necklaces, necktie fasteners, lapel pins, money clips, necklace pendants, bracelet pendants, and earring pendants, piggy banks, tie pins, tie slides, trophies and watches; cardboard; photographs, adhesives for stationery or household purposes; playing cards, printers' type; binders; bookends, bookmarkers, boxes for pens, calendars, tablets, cards, pads, pens, pencils, folders, paperweights, pen and pencil holders, photograph stands, rulers, erasers, markers, desk sets, and bumper stickers, leather and imitations of leather; animal skins, hides; trunks and travelling bags, umbrellas, travel bags, luggage, school bags, back packs, beach bags, duffel bags, fanny packs, and umbrellas; steelwool; unworked or semi-worked glass (except glass used in building); earthenware (not included in other classes); mugs and sports bottles; t-shirts, shirts, tank tops, boxer shorts, leather jackets, sweaters, sweatshirts, sweat suits, coveralls, jackets, pants, shorts, ties, bandannas, headwear, namely baseball caps and night caps, bow ties, cardigans, gloves, gym suits, hats, jackets, jogging suits, neckties, polo shirts, scarves, infant rompers, smocks, socks and visors; sporting goods, namely footballs; decorations for Christmas trees; objects for children to play with, namely stuffed toys, plush toys, puppets, dolls, bean bags, board games, video games; and seasonal ornamentation, namely Christmas tree ornaments.

Amended Reply

6. The Plaintiff specifically denies the allegations in paragraph 22 of the Amended Statement of Defence and Counterclaim. The Plaintiff further states that the PENTIUM trade-mark has been and is used in association with the wares listed in trade-mark registration no. TMA534,128 in the normal course of the Plaintiff's trade. Such wares are manufactured for the Plaintiff under license and the Plaintiff maintains control over the character or quality of the wares.

25 The above-cited paragraphs from the pleadings show there are unadmitted allegations concerning the issues of confusion, infringement and depreciation. Accordingly, it may well be that the disputed questions could be relevant to the action and the general rule concerning the scope of discovery examination is that questions about those issues should, in the usual course, be answered. However, the matter does not end there.

26 In Reading & Bates Construction Co. v. Baker Energy Resources Corp. (1988), 24 C.P.R. (3d) 66 (F.C.T.D.), the Court reviewed the general principles applicable to the discovery examination process. While acknowledging the primacy of relevancy and that relevancy is a matter of law, not discretion, the Court has also recognized that there are limits to the discovery process and set forth a list of general principles. The following apply to the present situation and were set out in Reading & Bates, supra, by Justice McNair at pages 71-72:

...

3. The propriety of any question on discovery must be determined on the basis of its relevance to the facts pleaded in the statement of claim as constituting the cause of action rather than on its relevance to facts which the plaintiff proposes to prove to establish the facts constituting the cause of action. ...
4. The court should not compel answers to questions which, although they might be considered relevant, are not at all likely to advance in any way the questioning party's legal position: Canex Placer Ltd. v. A.-G. B.C., supra; and Smith, Kline & French Laboratories Ltd. v. A.- G. Can. (1982), 67 C.P.R. (2d) 103 at p. 108, 29 C.P.C. 117 (F.C.T.D.).
5. Before compelling an answer to any question on an examination for discovery, the court must weigh the probability of the usefulness of the answer to the party seeking the information, with the time, trouble, expense and difficulty involved in obtaining it. Where on the one hand both the probative value and the usefulness of the answer to the examining party would appear to be, at the most, minimal and where, on the other hand, obtaining the answer would involve great difficulty and a considerable expenditure of time and effort to the party being examined, the court should not compel an answer. One must look at what is reasonable and fair under the circumstances: Smith, Kline & French Ltd. v. A.-G. Can., per Addy J. at p. 109.
6. The ambit of questions on discovery must be restricted to unadmitted allegations of fact in the pleadings, and fishing expeditions by way of a vague, far-reaching or an irrelevant line of questioning are to be discouraged: Carnation Foods Co. Ltd. v. Amfac Foods Inc. (1982), 63 C.P.R. (2d) 203 (F.C.A.); and Beloit Canada Ltée/Ltd. v. Valmet Oy (1981), 60 C.P.R. (2d) 145 (F.C.T.D.).

27 In the present case, the Prothonotary determined that the remaining questions, that is questions 526, 810, 812, 813 and 814 were too broad. He characterized them as being in the nature of a "fishing expedition".

28 Question 526 relates to the production of each offer of purchase and sale relative to each house sold by the Defendant, as well as a list of the names and current location of each customer to whom the Defendant had sold a house. It appears that the Prothonotary found this question to be too broad, relative to unadmitted allegations in the pleadings. In my opinion, that conclusion is reasonable, particularly when that question is viewed in the context of the entire discovery examination of Mr. Cuplowsky.

29 Question 810, a request that the Defendant produce a list of suppliers and subcontractors with contact information, suffers from the same flaw, in my opinion. I see no error in principle in the Prothonotary's decision to uphold the Defendant's refusal to respond to this question.

30 Questions 812, 813 and 814 relate to a request for production of emails received at the email address "sales@pentiumconstruction.com". The Plaintiff allegedly seeks those emails in an effort to show actual confusion. However, according to the discovery examination of the Plaintiff's representative, the Plaintiff was aware that there was no evidence of such confusion. I refer to questions 30 and 57 that were posed to the Plaintiff's representative and the answers that were provided. This evidence was before the Prothonotary and formed part of the record on this appeal.

31 As well, I refer to Rule 242(1) which addresses the grounds upon which a party may object to questions during the discovery examination. Rule 242(1)(c) and (d) provides as follows:

> A person may object to a question asked in an examination for discovery on the ground that
>
> ...
>
> (c) the question is unreasonable or unnecessary; or
> (d) it would be unduly onerous to require the person to make the inquiries referred to in rule 241.
>
> * * *
>
> Une personne peut soulever une objection au sujet de toute question posée lors d'un interrogatoire préalable au motif que, selon le cas :
>
> ...
>
> c) la question est déraisonnable ou inutile;
> d) il serait trop onéreux de se renseigner auprès d'une personne visée à la règle 241.

32 I refer to the affidavit of Mr. Cuplowsky dated July 10, 2003, filed as part of the record before the Prothonotary. In his affidavit, Mr. Cuplowsky deposed that the Defendant could not access any emails that had been deleted from its files and further, that contact by the Plaintiff with the Defendant's customers, suppliers and subcontractors might be injurious to the Defendant's business. Mr. Cuplowsky was not cross-examined on this affidavit. Accordingly, I conclude that the Defendant has established a legitimate basis for objecting to the questions about the emails and contact with its customers and trades people.

33 In these circumstances, I conclude that the Prothonotary did not err in upholding the Defendant's refusal to answer these outstanding questions. The questions, as posed, are too broad and represent an improper attempt to elicit information when the Plaintiff itself is unaware of any instances of actual confusion, as alleged in the pleadings.

34 In the result, I see no basis for interfering with the Order under appeal and the appeal is dismissed with costs.

ORDER

The appeal is dismissed, with costs.

HENEGHAN J.

cp/e/qw/qlklc/qlhbb

Environmental Defence INTERROGATORY #6 List 1

Reference: Ex. B, Tab 1, Schedule 5, Page 10, Table 1

Interrogatory

Please provide the OPA's estimate of the peak demand (MW) for electricity for the KWCG area and each of the six subsystems shown in Table 1 for each year from 2013 to 2026 inclusive: a) before conservation and demand management (CDM) and distributed generation (DG); b) net of CDM; and c) net of CDM and DG.

Response

Please refer to Attachment 1 to this exhibit.

Gross (MW)														
Subsystem	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
South-Central Guelph 115 kV	131	139	144	150	155	161	167	172	175	179	182	185	188	195
Kitchener-Guelph 115 kV	272	275	281	294	297	301	304	317	321	326	330	334	339	341
Waterloo-Guelph 230 kV	480	489	498	507	518	535	550	560	571	602	615	621	634	653
Cambridge 230 kV	392	410	427	443	459	475	491	504	518	534	549	565	581	597
Kitchener and Cambridge 230 kV	506	528	547	557	577	596	616	622	639	659	678	697	716	736
Other Stations in the KWCG Area	216	221	227	233	237	242	247	251	256	242	247	258	263	268
Total KWCG Area	1605	1651	1696	1740	1784	1834	1883	1922	1963	2007	2051	2095	2141	2192

Net of CDM (MW)														
Subsystem	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
South-Central Guelph 115 kV	124	130	133	137	141	145	149	154	156	158	161	163	166	172
Kitchener-Guelph 115 kV	258	256	256	265	264	264	264	275	276	278	281	283	286	288
Waterloo-Guelph 230 kV	457	458	460	463	467	478	489	493	501	528	538	542	553	569
Cambridge 230 kV	374	385	395	406	417	428	440	449	460	473	486	500	514	528
Kitchener and Cambridge 230 kV	482	494	506	509	521	535	548	550	564	579	595	611	628	646
Other Stations in the KWCG Area	205	205	207	210	211	213	215	217	220	205	208	218	221	225
Total KWCG Area	1526	1542	1563	1584	1605	1635	1666	1690	1717	1749	1782	1818	1855	1900

Net of CDM and DG (MW)														
Subsystem	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
South-Central Guelph 115 kV	123	129	132	136	140	144	148	153	155	157	159	162	165	170
Kitchener-Guelph 115 kV	257	254	255	264	263	263	263	274	275	277	280	282	285	287
Waterloo-Guelph 230 kV	448	448	450	451	455	466	477	482	489	516	526	530	541	557
Cambridge 230 kV	372	383	393	404	415	426	438	447	458	471	484	498	512	526
Kitchener and Cambridge 230 kV	480	491	504	506	519	532	546	548	561	576	592	609	626	643
Other Stations in the KWCG Area	199	199	199	201	203	205	206	209	212	196	199	210	213	217
Total KWCG Area	1508	1522	1540	1559	1580	1610	1640	1665	1692	1723	1757	1792	1829	1875

FIRST NATIONS & MÉTIS CONSULTATION PROCESS

1.0 INTRODUCTION

Hydro One recognizes the importance of early engagement with First Nations and Métis communities regarding the Guelph Area Transmission Refurbishment Project ("**the Project**"). The following sets out Hydro One's process for engaging with First Nations communities who may have an interest in, or may be potentially affected by, the Project.

2.0 IDENTIFICATION OF FIRST NATIONS & MÉTIS COMMUNITIES

On July 18, 2008, Hydro One sent a letter including a Project Study Area Map to the Ontario Ministry of Aboriginal Affairs and Indian and Northern Affairs Canada (now known as Aboriginal Affairs and Northern Development Canada) requesting input on First Nations and/or Métis communities with potential interests in or who may be potentially affected by the Project. In a letter to Hydro One dated September 26, 2008, the Ontario Ministry of Aboriginal Affairs advised that the project did not appear to be located in an area where First Nations may have existing or asserted rights that could be impacted by the Project. In a letter to Hydro One dated August 4, 2008, Indian and Northern Affairs Canada determined that a specific claim has been submitted by Mississaugas of the New Credit First Nation and advised Hydro One to apprise the First Nation of its intentions. In addition, Indian and Northern Affairs Canada indicated that Six Nations of the Grand River First Nation is in the general vicinity of the Project area. See **Exhibit B, Tab 6, Schedule 6, Attachment 1** for copies of the above communications.

On April 27, 2012, Hydro One sent a letter including a Project Study Area Map to the Ontario Ministry of Energy indicating that Hydro One would be re-commencing work on the Project. In this letter, Hydro One also indicated that it intends to re-notify Mississaugas of the New Credit First Nation and Six Nations of the Grand River First Nation of project re-commencement and requested that the Ontario Ministry of Energy advise of additional First Nations interests that may occur within the general vicinity of the Project area. On June 25, 2012, the Ontario Ministry of Energy responded advising that they had determined that there is a very low likelihood the Project will potentially affect any First Nations or Métis rights and therefore recommended that consultation is not necessary. See **Exhibit B, Tab 6, Schedule 6, Attachment 2** for copies of the above communications.

3.0 ENGAGEMENT PROCESS FOR FIRST NATIONS & MÉTIS COMMUNITIES

Hydro One's First Nations and Métis engagement process is designed to provide relevant Project information to neighbouring First Nations and Métis communities in a timely manner and for Hydro One to respond to and consider issues, concerns or questions raised by First Nations and Métis communities in a clear and transparent manner throughout the regulatory review processes (e.g., the Environmental Assessment ("**EA**") and OEB processes). Engagement activities with potentially impacted First Nations and Métis communities include:

- Providing Project-related information to neighbouring First Nations and Métis communities including, project notification letters which describe the need and nature of the project, and ensuring that all publicly available information is also made available to First Nations and Métis communities;
- Offering meetings with the First Nations and Métis communities to provide Project-related information, to identify concerns, issues or questions about the Project, and

respond to questions and wherever possible, address concerns, in relation to the Project;

- Providing information, when requested, on the OEB's regulatory process, the EA process or any other decision-making processes applicable to the Project;
- Giving consideration to all issues and concerns raised by the First Nations and Métis communities as to how the Project may affect them;
- Recording all forms of engagement with the First Nations and Métis communities, maintaining a record of the concerns and issues raised by the First Nations and Métis communities regarding the Project and Hydro One's responses thereto, and communicating the same with the Ministry of Energy.

4.0 ENGAGEMENT TO DATE WITH FIRST NATIONS COMMUNITIES

Hydro One has undertaken the following engagement activities:

- On June 2, 2009 and November 10, 2009, Hydro One sent letters notifying the Mississaugas of the New Credit First Nation and Six Nations of the Grand River First Nation Elected Council ("**the First Nations**") of the Project, advised them of planned Public Information Centres concerning the Project, and offered to meet with them to discuss the Project.
- On August 9, 2010, Hydro One contacted the First Nations by letter and email to update them on the Project and repeated the offer to meet.
- On August 26, 2010, Hydro One contacted the Haudenosaunee Confederacy Council by letter to update them on the Project and to extend an offer to meet.
- On September 7, 2010, Hydro One received a reply from Six Nations of the Grand River First Nation Elected Council via email indicating a desire to provide input on the Project.
- On October 6, 2010, Hydro One and Six Nations of the Grand River First Nation Elected representatives met to discuss the Project.

- On October 28, 2010, Hydro One transmitted via Canada Post and electronic mail to Six Nations of the Grand River First Nation Elected Council, a meeting follow-up package that addressed all action items identified in the meeting minutes.
- On May 22, 2012, Hydro One transmitted via Canada Post and electronic mail to Mississaugas of the New Credit First Nation, Six Nations of the Grand River First Nation Elected Council, and the Haudenosaunee Confederacy Council notification of Project re-commencement, planned Public Information Centres and an offer to meet to discuss the Project.
- On June 14, 2012, Hydro One telephoned Mississaugas of the New Credit First Nation, Six Nations of the Grand River First Nation Elected Council, and the Haudenosaunee Confederacy Council to follow-up with the Project notification letter sent on May 22, 2012.
- On June 14, 2012, the Haudenasaunee Confederacy Council indicated by telephone that they would not be attending the Public Information Centre and will be in contact with Hydro One regarding the Project. Hydro One has not received any additional correspondence from the Haudenosaunee Confederacy Council.

See **Exhibit B, Tab 6, Schedule 6, Attachment 3** for copies of the above communications.

5.0 SUMMARY

Hydro One is prepared to continue engagement efforts with these First Nations relating to the Guelph Area Transmission Refurbishment Project. To date, no issues or concerns have been raised by the above mentioned First Nations communities. Hydro One will work to resolve any issues or concerns in the event that anything should arise.

STAKEHOLDER AND COMMUNITY CONSULTATION

1.0 INTRODUCTION

Hydro One identified and consulted with affected property owners and stakeholders who may have an interest in the proposed transmission refurbishment project. This exhibit describes Hydro One's consultation process, input received and the results to date. The Class EA and consultation for this project were initiated in 2009. In March 2012, the OPA advised Hydro One that the regional planning study had advanced sufficiently to confirm the need and scope of the Guelph Area Transmission Refurbishment Project (**"GATR"**). The majority of this exhibit and its appendices focus on the consultation undertaken after the Class EA process recommenced in spring 2012.

Hydro One's practice is to continue communication with property owners, residents and local officials in the project area through to project completion, in an effort to ensure any questions or concerns during the design and construction phase are adequately addressed. Hydro One has also committed to keeping municipal and county officials and government agency representatives informed of the Project's status, as well as individuals who have asked to be on the project contact list.

Hydro One carried out a parallel engagement process with neighbouring First Nations communities as described in **Exhibit B, Tab 6, Schedule 6**.

2.0 PUBLIC CONSULTATION OBJECTIVES AND APPROACH

The intent of the public consultation process is to identify and inform affected and potentially-affected property owners, stakeholders, government agencies and ministries, and members of the general public about the project and to provide opportunities for all parties to ask questions and provide their feedback. The consultation process is initiated as early as possible to allow for the identification of potential issues. Hydro One will attempt to address and resolve all issues in order to complete the Class EA process and prior to the formal OEB review and public hearing process.

Several fundamental principles underpin Hydro One's approach to communication and consultation, including: early, ongoing and timely communications; clear and complete project information and documentation; open, transparent, and flexible communications and consultation processes; and respectful dialogue with all stakeholders.

Hydro One uses a variety of methods to communicate with identified stakeholders about a proposed undertaking and to establish the opportunity for two-way communication. For this project, communications vehicles included: newspaper advertisements; correspondence and in some cases also meetings with key stakeholders; Canada Post ad mail or direct mail notices to directly-affected property owners and those in close proximity to the facilities Hydro One is proposing to refurbish; the establishment of a project website (www.HydroOne.com/projects) and a designated contact person for ongoing communication; a series of public information centres ("**PICs**") – two in 2009 and two in 2012 upon recommencement of the Class EA – to speak directly with interested and/or affected parties; and one community information meeting in 2012 to discuss issues of interest and concern to residents in a particular neighbourhood. The activities and outcomes of the consultation process are described in the following sections.

All issues identified during the consultation process are given full and fair consideration, and Hydro One will develop project plans to address them, where appropriate. A summary of the key issues raised and how Hydro One addressed them is provided in Section 5 of this exhibit.

3.0 CONTACT WITH STAKEHOLDERS AND THE PUBLIC

The OPA actively supported Hydro One in communicating information relative to the need for the project. OPA staff accompanied members of Hydro One's project team to meetings with municipal officials, and attended the PICs and the community information meeting.

Guelph Hydro Inc. (**"Guelph Hydro"**) supports the project and sent representatives to all meetings with the City of Guelph officials and all public consultation events held within the city. Guelph Hydro also assisted Hydro One with property owner notification for the Notice of Recommencement mailing in May 2012. Ongoing communication between Hydro One and Guelph Hydro ensured that Guelph Hydro's leadership team and employees were briefed on the project status and aware of all communications being sent to their customers and City officials. Letters of support from Guelph Hydro and the other LDCs serving the Kitchener-Waterloo-Cambridge-Guelph are attached in **Exhibit B, Tab 6, Schedule 2**.

3.1 Municipal and County Officials

Prior to notifying property owners, stakeholders and the public and before advertising for the Public Information Centres, Hydro One contacted the Clerk or Chief Administrative Officer of the County of Wellington, the Township of Centre Wellington and the City of Guelph by telephone to arrange for project information to be circulated in advance to Council. Hydro One, in its June 2012 communications, invited members of council and staff to the planned PICs and also offered to make a deputation on the project. Hydro One also communicated directly with City of Guelph councillors whose Wards fall within the project area and offered to brief them and their staff. Please see **Exhibit B, Tab 6,**

Schedule 5, Attachment 1 for examples of the correspondence sent to municipal and county officials in 2012 upon resumption of the Class EA process for this project (June 5), Notice of Completion of draft ESR (August 8) and Notice of Completion of Class EA (November 8, 2012).

Meetings were held in May 2012 with elected officials and senior staff from the Township of Centre Wellington and the County Councillor representing the Guelph North Junction area, and also with City of Guelph staff representing a range of departments. A letter of support for the project from Chief Administrative Officer Pappert, City of Guelph is attached in **Exhibit B, Tab 6, Schedule 2, Attachment 3.**

3.2 Members of Provincial Parliament ("MPPs") and Members of Parliament ("MPs")

The project area falls within the provincial and federal ridings of Guelph and Wellington – Halton Hills. The MPPs and MPs for these ridings were notified in advance of all public communications about the project and invited to the public information centres. Hydro One also offered to brief the MPPs and MPs and their constituency staff at key stages of the project. Hydro One sent correspondence to MPPs and MPs in 2012 similar to those in Attachment 1 above.

3.3 Government Ministries and Agencies

Prior to introducing the project to local stakeholders and members of the public in 2009, and prior to recommencing work on the Class EA in 2012, Hydro One informed and sought input on the proposed undertaking from a broad range of provincial government ministries and agencies, federal departments, and the Grand River Conservation Authority. The government agencies were kept informed of project status throughout the consultation process and made aware of public and stakeholder consultation events. The government agency list can be found in the appendices of the final Environmental Study Report (**"ESR"**) for this project, posted on the project website at www.HydroOne.com/projects. Similar correspondence letters, as provided in Attachment 1, were also sent to government agencies in 2012.

3.4 Community Stakeholders

Hydro One identified and provided project information to several local interest groups, including Chambers of Commerce, agricultural associations, and nature/naturalist groups, etc. Theses stakeholders were invited to participate in public consultation events and to provide input on the proposed undertaking and on the draft ESR for the project. The stakeholder list can be found in the appendices of the final ESR for this project, posted on the project website at www.HydroOne.com/projects.

4.0 PUBLIC INFORMATION CENTRES

4.1 Schedule and Notification

Hydro One held a total of four public information centres. The first two PICs were held in 2009: the first one on June 10 at the First Christian Reformed Church in Guelph, and the second one on November 25 at the Marden Community Centre, northwest of Guelph. These initial PICs served to introduce the proposed undertaking to residents who live in the project study area and to give them an opportunity to speak with and provide comments to members of Hydro One's project team and representatives from the OPA.

Hydro One used various methods to notify the local community and stakeholders about the project and the PICs, including Canada Post unaddressed ad mail, flyers, direct mail and newspaper ads. A Notice of Commencement newspaper advertisement and invitation to PIC #1 was placed in the *Guelph Mercury* on May 29 and June 5, 2009, and in the *Guelph Tribune* on May 29 and June 2, 2009. For PIC #2, a newspaper advertisement was placed on November 13 and 20, 2009, in the *Guelph Mercury*, the *Guelph Tribune* and the *Wellington Advertiser*.

The newspaper ad contained details about the proposed undertaking and included a map of the project study area. It also identified a Hydro One contact name and contact information and a link to Hydro One's website where more information about the project could be obtained. A copy of the newspaper ad was provided in advance to municipal officials, MPPs and MPs so they would be prepared to handle any questions they might receive from their constituents. In addition, property owners within the identified study area were notified of the project and of the public information centres by way of a flyer sent by Canada Post unaddressed ad mail.

When Hydro One resumed the Class EA process in 2012, two more PICs were scheduled to reintroduce the project to local stakeholders. PIC #3 was held on June 14, 2012, at the First Christian Reformed Church in Guelph, which is located close to Cedar TS. PIC #4 was held on June 19, 2012, at the Ponsonby Public School which is in the vicinity of Hydro One's Guelph North Junction.

Hydro One used various methods to advise the local community and stakeholders about the recommencement of the project and the planned PICs including direct addressed mail to all properties (about 1,000 in total) within 150 metres of the facilities to be upgraded in the City of Guelph. This list of premise addresses only (names withheld) was provided by Guelph Hydro. Hydro One Real Estate also provided names and addresses for a direct mailing to owners of properties immediately adjacent to the transmission corridor along Deerpath Drive in Guelph, and those properties on Bronwyn Court in Guelph, on which

Hydro One has easement rights. Hydro One Real Estate also provided current property owner information for about 25 properties within 500 metres of the Guelph North Junction so that these owners could be directly notified about the recommencement of the study. A copy of the post card notice and PIC invitation mailed to these property owners / occupants is attached as **Exhibit B, Tab 6, Schedule 5, Attachment 2**.

For broad public notification, a Notice of Recommencement newspaper advertisement and invitation to PICs #3 and #4 was placed in the *Guelph Mercury* on June 7, 2012, the *Guelph Tribune* on June 12 and 14, 2012, and the *Wellington Advertiser* on June 15, 2012. A copy of the Notice of recommencement newspaper advertisement is attached as **Exhibit B, Tab 6, Schedule 5, Attachment 3**.

4.2 Public Information Centre Format

The PICs were held in an open house format where visitors could drop in anytime between 5 p.m. and 8 p.m. After signing in at the registration desk, visitors were provided with handouts of the display panels and a comment form on which they could record their feedback both on the project in general and on the PIC. Handouts on EMFs and energy conservation were also available. Hydro One and OPA employees representing various disciplines were on hand to speak one-on-one with visitors about the proposed project and to answer their questions.

Hydro One's experience with the open house format over the years is that it provides an effective way for visitors to gain a better understanding of the project being proposed, while giving them the opportunity to freely and informally express their views and to direct any questions to the appropriate technical or subject-matter expert.

Ontario Energy Board (Board Staff) INTERROGATORY #1 List 1

Interrogatory

Historical and Forecast Electricity Demand

Reference:

(1) Ontario Power Authority Report, March 2013-Exhibit B/Tab 1/Schedule 5

Preamble:

Board staff seeks clarification of the load growth forecast in the KWCG area:
The OPA reports (Reference 1 at line 10, page 8) that demand "… is expected to continue to grow at a pace of nearly 3% per year between 2010 and 2023."

In Reference (1), at page 6, line 12 the OPA advises that the demand for electricity recovered to pre-recession levels in the summer of 2010.

Reference 2 at line 23 indicates that customers of Cedar TS will reduce the exposure of customers supplied by Cedar TS to supply outages, provide increased supply diversity and reliability of supply, lower losses and improve operational flexibility to the area.

Question(s)/Request(s):

1. Has the OPA reviewed the figures from the area LDCs so that it is able to verify the forecast growth rates and assure there is no double counting by the LDCs making up the area load? Does the OPA adopt the forecast growth as it own evidence
2. Is the OPA defining the pre-recession period as 2004-2007 as shown in Figure 3 page 9 of ref 1 as "pre-economic downturn"?
3. Is it correct to deduce from the Figure 3, page 9 that the growth from 2005 to 2012 was 0%?
4. A 3% growth rate for 2010 to 2023 (2% net of CD and DG) is reflected in Reference 1, page 13, line 10. However, electrical demand from 2004 to 2011 is lagging by 1% or more behind the GDP growth, yet in the years 2010-2023 it is equal. What are the factors that make this higher demand a credible result? Please provide comment on the following table:

	2004-2007	2004-2011	2010-2023	
GDP Per Ref 1	>3% lines10-11, p9	2% lines 8-9,p9	2%	
Actual/forecast [Per Ref 1]	3% [page 8, line 9]	1% [page 8 lines 8-9]	2% net of CD & DG [Note page 9 in Fig 3]	
ratio	>1:1	2:1	1:1	

5. Reference 1, Table 1, page 10 indicates an increase in Demand forecast for "Kitchener and Cambridge" from 2012 to 2013 as 401 to 506 MW, which is greater than 25%. Also Reference 1, Figure 6, page 21 has a large discontinuity between 2012 and 2013 in the net Demand. This is not identified as a high growth area in the paragraph at line 11 on page 10. Please explain the basis for this specific increase.

6. Figure 3 shows no actual growth in demand from 2010 to 2012, a period which overlaps the 2010-2013. Has this "actual" been considered in the forecast for 2010-2023? What average annual growth is predicted then for the period 2012-2023?

7. Reference 1, section 5.1 "Need for Additional Supply Capacity", at page 13 identifies 3 need areas. Please clarify if each of the "needs" is met by the upgrading which is the subject of the current Leave to Construct application. If the current project does not on its own fulfil the need then indicate which additional projects will be required to meet that need.

8. Reference 1 Section 6.1page 17, line 19 indicates that 35% of the load growth will be off-set by Conservation. Please

   a) provide information on the confidence level or certainty with which this will be achieved
   b) indicate the consequences of reductions in load through conservation being under-achieved, say by 50%
   c) indicate the possibility for increasing the off-set through conservation by further expenditure.

Response

1. For regional planning, it is the responsibility of the LDCs to provide demand forecasts based on their knowledge of proposed developments and growth trends in their service area. The OPA's role in the load forecasting process is to provide a provincial perspective and facilitate the discussion between area LDCs. The sharing of LDC forecasts and demand growth information avoids the potential for the double counting of load.

   The OPA reviewed the KWCG area's long-term demand forecast. Based on economic forecasts for the Kitchener Census Metropolitan Area ("CMA") obtained from an independent economic forecast service, OPA's analysis shows that there are factors that support the demand growth trend. These factors include forecasted GDP, population and household growth.

   The KWCG working group, of which the OPA is a member, has adopted the KWCG area demand forecast.

2. For the purpose of the report, the period between 2004 and 2007 is used to describe the few years leading up to the 2008/2009 recession, i.e. the pre-economic downturn or pre-recession period.

3. It is correct to deduce from Figure 3, page 9 that the growth rate from 2005 to 2012 was 0%. It should be noted that the demand in the KWCG area was impacted by the economic downturn around 2008/2009 and the demand in the KWCG area has since recovered to the 2005 demand level.

4. While the demand for electricity is influenced by a number of factors such as economic, household and population growth, the OPA recognizes that these factors are indicative of electricity demand growth and do not necessarily have a one to one correlation with electricity consumption as indicated by the variation in GDP to electricity demand growth rates shown above.

   While economic indicators such as GDP, household growth and population provide directional support to the forecast, they were not directly used in the development of the forecast. The forecast was developed by the LDC's and supported by the working group based on their understanding of local trends.

5. The difference observed between the 2012 actual and the 2013 forecast on Cambridge-Kitchener 230 kV is due to the timing of summer shutdown for a large industrial customer in the Cambridge area. Cambridge and North Dumfries Hydro ("CNDH") noted that the KWCG area peak and the provincial peak both occurred in July (for 2012) when one of CNDH's large industrial customers was on a week-long summer shutdown. If the large industrial customer was in production on the 2012 peak day, the load on the Cambridge-Kitchener 230 kV system would have been about 10 MW higher than the peak value recorded in 2012. For purposes of the forecast, CNDH assumed that the large industrial customer was in production during 2012 since it cannot be assumed that the large industrial customer will always be out of production during peak demand conditions. While the Cambridge-Kitchener 230 kV subsystem is not identified as a high growth area on page 10, this subsystem includes the Cambridge 230 kV subsystem (a high growth area) and several other stations in the Kitchener area.

   The difference observed between the 2012 actual and the 2013 forecast on the Cambridge-Kitchener 230 kV subsystem can also be explained by weather conditions assumptions and impact of conservation and distributed generation. The 2012 summer peak occurred under slightly above median weather conditions and has accounted for the impact of conservation and distributed generation. The gross forecast shown in Table 1 has been adjusted for extreme weather conditions for the purpose of planning and does not yet account for the impact of distributed generation and conservation.

6. The 2010 coincident summer peak for the KWCG area was initially used to establish the reference demand forecast and updates were made to the reference case after review of the 2012 actual demand information. The average annual growth predicted for the period 2012-2023 is 2.9% before the impact of conservation and distributed generation.

7. As stated in Section 5.1 of the Ontario Power Authority's Report (Exhibit B, Tab 1, Schedule 5) over the next ten years, demand for electricity is expected to exceed the existing

system's load meeting capability in the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems. To address these three area needs, an integrated solution is recommended which includes the following upgrading, which is the subject of this Leave to Construct application, and other measures:

- upgrading approximately 5 km of the existing 115 kV double circuit transmission line section between CGE Junction and Campbell TS to a 230 kV double circuit configuration (the subject of this Leave to Construct application);
- conservation and distributed generation resources;
- installing two new 230/115 kV autotransformers, four 115 kV breakers, and advancing the relocation of the existing Hydro One Distribution Operating Centre at Cedar TS;
- transferring an existing directly connected customer in the Guelph area to the distribution system; and
- installing a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support.

8.

a) The amount of load growth that will, in fact, be off-set by conservation between 2010 and 2023 is a function of the rate of electricity demand growth and the amount of planned conservation savings.

KWCG area demand growth is expected to continue to grow at a pace of nearly 3% per year between 2010 and 2023 based on forecasts provided by the area LDCs. The nearly 270 MW of planned peak demand reduction from conservation achievement in the KWCG area by 2023 is based on an allocation of existing provincial targets.

The OPA's degree of confidence in the amount of demand growth and the amount that will be offset by conservation is highest in the near term. Over the longer-term planning horizon, load growth may be higher or lower than forecast due to changes in various factors, including actual economic activity, household growth, population growth and electricity prices. Likewise, the performance of planned conservation resources may be higher or lower than anticipated due to changes in various factors, including actual savings from province-wide conservation and demand management programs, building codes and equipment standards and customer response to time-of-use pricing. Further, the OPA's degree of confidence in its province-wide conservation savings forecast is higher than its regional conservation savings forecast which is based on an allocation of provincial targets.

Despite the increased uncertainty over the longer term planning horizon, the OPA's load forecast net of conservation savings provides reasonable context for assessment of options to meet the near- and medium-term needs of the KWCG area and is based on best available information. Further, the OPA will address the uncertainty over the longer term by continuing to monitor demand, carrying out evaluation, measurement and verification on conservation programs and making adjustments as required within the KWCG area.

b) Given that the majority of the KWCG area needs already exist today, a higher demand scenario (e.g. conservation being under-achieved by 50%) does not significantly impact the needs in the near- and medium-term. However, under a higher demand scenario, there is greater urgency for solutions to be put in place to address the near- and medium-term needs, and even with the near-and medium- term transmission reinforcements to address these needs, there may be additional supply capacity needs towards the end of decade.

c) Based on the OPA's experience with conservation programs, the amount of planned conservation, and the immediate nature of the needs, it is the OPA's view that additional conservation is not a feasible means for addressing the KWCG area's near- and medium-term needs.

While it may be possible to spend more to incrementally increase the amount of load growth off-set by conservation, it is the OPA's view that further solutions would in any event be needed to fully address the area's electricity supply needs; a capacity gap of nearly 70 MW remains in 2016, growing to nearly 200 MW by 2023, in the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems.

Additionally, conservation cannot aid in the restoration of power to customers following a major transmission outage, and therefore cannot resolve the KWCG area's supply interruption and restoration needs. It is therefore the OPA's view that further expenditures to achieve incremental conservation savings that are insufficient to fully address the area's needs would not be prudent.

The OPA will continue to monitor conservation results in the KWCG area and look for opportunities for further cost effective conservation to address supply capacity needs of the area over the long term.

LETTERS OF ENDORSEMENT FOR THE PROJECT

Attachment 1	Guelph Hydro	Barry Chuddy	July 16, 2012
Attachment 2	Guelph Hydro	Kazi Marouf	July 16, 2012
Attachment 3	City of Guelph	Ann Pappert	July 27, 2012
Attachment 4	Kitchener-Wilmot Hydro	J. Van Ooteghem	October 19, 2012
Attachment 5	Cambridge and North Dumfries Hydro Inc.	Ian Miles	October 22, 2012
Attachment 6	Waterloo North Hydro Inc.	Rene W. Gatien	November 1, 2012

Barry Chuddy
Chief Executive Officer

395 Southgate Drive
Guelph, ON N1G 4Y1
519.837.4727 Fax 519.836.1055
bchuddy@guelphhydro.com
www.guelphhydro.com

July 16, 2012

Mr. Mike Penstone
Vice President of Transmission Projects Development, Hydro One
Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

Dear Sir,

Re: Hydro One's Guelph Area Transmission Refurbishment Project ("GATR")

Guelph Hydro and other local utilities, including Hydro One, participated in a joint planning study sponsored by the Ontario Power Authority (OPA) called the "Guelph Area Transmission Refurbishment Project ("GATR")". This study identified various system constraints and reliability concerns, and looked at the future need for expansion of transmission facilities to allow growth in the region and an acceptable level of system reliability compared to other areas of the Province.

As a result of the inputs to the Study, Hydro One completed a thorough analysis of all options and the information provided was endorsed by all participating LDCs. Further, this project will address the urgent need for additional supply to the City of Guelph while still maintaining a high reliability of supply. To that end, Guelph Hydro fully supports this project as proposed by Hydro One and recommends that the project proceed as soon as possible.

Sincerely,

Barry Chuddy
Chief Executive Officer
Guelph Hydro Inc.

:km

cc: K.Marouf

Guelph Hydro
Electric Systems Inc.

Kazi Marouf
Chief Operations Officer

395 Southgate Drive
Guelph, ON N1G 4Y1
519.837.4702 Fax 519.836.1055
kmarouf@guelphhydro.com
www.guelphhydro.com

July 16, 2012

Mr. Mike Penstone
Vice President of Transmission Projects Development, Hydro One
Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

Dear Sir,

Re: Hydro One's Guelph Area Transmission Refurbishment Project ("GATR")

Guelph Hydro and other local utilities, including Hydro One, participated in a joint planning study sponsored by the Ontario Power Authority (OPA) called the "Guelph Area Transmission Refurbishment Project ("GATR")". This study identified various system constraints and reliability concerns, and looked at the future need for expansion of transmission facilities to allow growth in the region and an acceptable level of system reliability compared to other areas of the Province.

As a result of the inputs to the Study, Hydro One completed a thorough analysis of all options and the information provided was endorsed by all participating LDCs. Further, this project will address the urgent need for additional supply to the City of Guelph while still maintaining a high reliability of supply. To that end, Guelph Hydro fully supports this project as proposed by Hydro One and recommends that the project proceed as soon as possible.

Sincerely,

Kazi Marouf, P. Eng.
Chief Operations Officer
Guelph Hydro Electric Systems Inc.

:km

cc: B. Chuddy

CITY OF Guelph
Making a Difference

July 27, 2012

RECEIVED
AUG 1 4 2012

Mr. Mike Penstone
Vice President of Transmission Projects Development, Hydro One
Hydro One Networks Inc.
483 Bay Street
Toronto, ON M5G 2P5

Dear Sir:

Re: Hydro One's Guelph Area Transmission Refurbishment Project ("GATR")

I have been advised that Guelph Hydro and other local utilities, including Hydro One, participated in a joint planning study sponsored by the Ontario Power Authority (OPA) called the "Guelph Area Transmission Refurbishment Project ("GATR")". This study identified various system constraints and reliability concerns, and looked at the future need for expansion of transmission facilities to allow growth in the region and an acceptable level of system reliability compared to other areas of the Province.

This project will address the urgent need for additional supply to the City of Guelph while still maintaining a high reliability of supply. We share these fundamental goals through the substantial progress we have already made toward the local generation targets in Guelph's Community Energy Initiative.

To that end, the City of Guelph fully supports this project as proposed by Hydro One and recommends that the project proceed as soon as possible.

Yours truly,

Ann Pappert
Chief Administrative Officer

T 519-837-5602
F 519-822-8277
E administration@guelph.ca

cc: B. Chuddy, Chief Executive Officer, Guelph Hydro Inc.
K. Marouf, Chief Operations Officer, Guelph Hydro Electric Systems Inc.
J. Urisk, Board Chair, Guelph Hydro Inc.

AP/sp

KITCHENER WILMOT HYDRO INC.
P.O. BOX 9010
301 VICTORIA STREET SOUTH
KITCHENER, ONTARIO
N2G 4L2

Jerry Van Ooteghem
President & C.E.O
Tel: (519) 745-4771
Fax: (519) 571-9338

October 19, 2012

Mr. Mike Penstone
Vice President of Transmission Projects Development, Hydro One
Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

Subject: Hydro One's Guelph Area Transmission Refurbishment Project ("GATR")

Dear Mr. Penstone:

Kitchener-Wilmot Hydro participated in a joint regional supply planning study along with the Ontario Power Authority, Hydro One and the other Local Distribution Companies. The study examined the adequacy of the transmission grid in Waterloo Region and Wellington County. This study identified various transmission system constraints and reliability concerns, and looked at the future need for expansion of Hydro One's facilities to accommodate growth and improve reliability at the affected utilities.

The study thoroughly analysed all options and identified that the Guelph Area Transmission Refurbishment (GATR) Project is urgently required to address some of the bulk supply issues in the study area and to maintain reliability of supply. To that end, Kitchener-Wilmot Hydro fully supports this project as proposed by Hydro One and recommends that the project proceed as soon as possible.

Yours truly,

J. Van Ooteghem

J. Van Ooteghem, P. Eng.
President & CEO

Energy+
CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.
1500 Bishop Street, P.O. Box 1060, Cambridge, Ontario N1R 5X6 • Telephone 519-621-3530 • Facsimile 519-740-3095
Website www.camhydro.com

RECEIVED OCT 25 2012

October 22, 2012

Mike Penstone
Vice President of Transmission Projects Development, Hydro One
Hydro One Networks Inc.
483 Bay Street
Toronto, ON M5G 2P5

Dear Mr. Penstone:

RE: HYDRO ONE'S GUELPH AREA TRANSMISSION REFURBISHMENT PROJECT ("GATR")

Cambridge and North Dumfries Hydro Inc. fully supports the Guelph Area Transmission Refurbishment Project. The GATR work will address some of the bulk supply issues in the region including improvement in both the supply capacity and restoration capability in the City of Cambridge and the Township of North Dumfries.

We recommend that Hydro One proceed as soon as possible.

Yours truly

CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.

Ian Miles

Ian Miles
President & CEO

Rene W. Gatien, P. Eng.
President & CEO

WATERLOO NORTH HYDRO INC.

PO Box 640
526 Country Squire Road
Waterloo ON N2J 4A3
Telephone 519-888-5544
Fax 519-886-8592
E-mail rgatien@wnhydro.com
www.wnhydro.com

November 1, 2012

Mr. Mike Penstone
Vice President of Transmission Projects Development, Hydro One
Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

Dear Mr. Penstone;

Re: Hydro One's Guelph Area Transmission Refurbishment Project ("GATR")

Waterloo North Hydro Inc. participated in a joint planning study called the "Guelph Area Transmission Refurbishment Project ("GATR")" with Hydro One and other local utilities.

This study identified various system constraints and reliability concerns, and looked at the future need for expansion of Hydro One's facilities to allow growth to the affected utilities.

Hydro One completed a thorough analysis of all options and the information provided was endorsed by all. Further, the project will address the bulk supply issues in the Guelph area and maintain reliability of supply.

To that end, Waterloo North Hydro Inc. fully supports this project as proposed by Hydro One and recommends that the project proceed as soon as possible.

Please do not hesitate to contact me if you have any questions or concerns.

Yours truly,

Rene W. Gatien

Rene W. Gatien P.Eng. MBA
President & CEO

Environmental Defence INTERROGATORY #39 List 1

Reference: Ex. B, Tab 1, Schedule 5, Section 5

Interrogatory

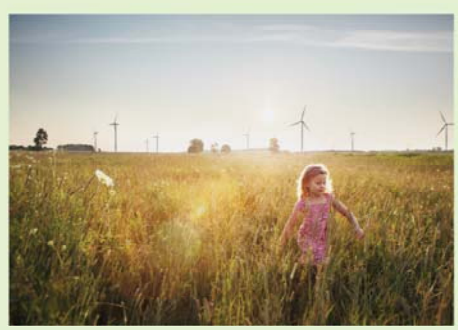
What is the transfer capability between the sources of supply in the KWCG area? In particular, what is the ability of one subsystem to support another subsystem that is experiencing an outage event? Please describe the limitations in transfer capability.

Response

The OPA confirmed with the LDCs that there is little to no capability to transfer load between different subsystems within the KWCG area in the event of an outage. Given the varying distribution voltages used to supply the subsystems in the KWCG area and the distances between them, it is difficult to transfer loads between the different subsystems.

Kitchener-Waterloo-Cambridge-Guelph Area

March, 2013



ONTARIO POWER AUTHORITY

page intentionally blank

Contents

1 Executive Summary

Near- and medium-term supply capacity and other reliability needs have been identified in the Kitchener-Waterloo-Cambridge-Guelph (KWCG) area. Specifically, three of the KWCG subsystems (the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems) are expected to exceed their supply capacity within the next ten years. Additionally, two subsystems (the Kitchener and Cambridge, and Waterloo-Guelph subsystems) do not comply with prescribed service interruption criteria. To address these needs, the OPA recommends an integrated package composed of 1) conservation, 2) distributed generation resources, and 3) transmission reinforcements in the KWCG area.

Conservation and distributed generation resources are important contributors to the integrated solution for addressing the needs of the KWCG area. Together, these resources are expected to off-set more than 35% of the forecast load growth in the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems between 2010 and 2023. By 2023 achievement from provincial conservation efforts within these subsystems is expected to reduce peak demand by over 130 MW at an estimated delivery cost of $65 million (based on an allocation of forecast expenditures for provincial conservation programs). Over the same time period, approximately 16 MW of distributed generation facilities are expected to come into service in South-Central Guelph, Kitchener-Guelph and Cambridge subsystems, representing a capital investment of approximately $70 million.

The transmission reinforcements recommended in the near-term include the Guelph Area Transmission Refurbishment (GATR) project, as well as a project to install a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support. The GATR project includes the installation of two new 230/115 kV autotransformers, four 115 kV circuit breakers, and the advancement of the relocation of the existing Hydro One Distribution Operating Centre at Cedar TS (approximately $52 million), rebuilding approximately 5 km of existing 115 kV double circuit transmission line between Campbell TS and CGE junction in Guelph to a 230 kV double circuit configuration (approximately $27.5 million), and installing two new 230 kV circuit breakers at a new station (Inverhaugh SS) at Guelph North Junction in Centre Wellington (approximately $16 million). Project completion for the GATR project is expected by the end of

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

2015. The installation of the Preston TS autotransformer facilities is a separate project that will be coordinated with completion of the GATR project and it is estimated to cost approximately $15 million to $25 million. Together these facilities will meet the near- and medium-term needs of the KWCG area, and substantially meet the KWCG area needs over the longer-term.

It is the OPA's view that this integrated solution is a cost-effective and technically-effective solution for meeting the capacity and reliability needs of the KWCG area.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

2 Introduction

The KWCG area is one of the larger population and electrical demand centres in Ontario. The existing electrical facilities in the area serve a diverse range of commercial, industrial and residential customers. The demand for electricity in the area is expected to grow substantially over the next 20 years, driven by population growth and strong economic activity. Much of the existing electricity infrastructure in the area is reaching capacity and therefore plans for future conservation, distributed generation and electricity infrastructure expansion and investment need to be developed and, as necessary, implemented in order to maintain a reliable supply of electricity to the area.

Planning to meet the electrical needs of a large area or region is done through a regional planning process that considers the multi-faceted needs of the region and seeks to address them through an integrated range of solutions. The plan takes into consideration, among other things, the electricity requirements, anticipated growth and existing electricity infrastructure. The outcome of the regional planning process is an integrated plan to guide electricity infrastructure, resource development and procurement decisions for the region. The plan's recommendations are typically organized into three timeframes: near-term (first 5 years), medium-term (5-10 years out) and longer-term (10-20 years out or longer). Solutions to address near-term and medium-term needs are presented as action items for immediate or early deployment, while solutions to address potential longer-term needs are identified along with the conditions that would trigger their implementation and the key development work required to maintain their viability. In this sense, regional plans are not static documents, but rather dynamic processes which evolve and are adapted as circumstances and conditions change.

A working group (the KWCG Working Group) was established in 2010 to develop a regional plan for the KWCG area. The KWCG Working Group was formed in a manner consistent with the process described by the Planning Process Working Group's Report to the OEB as part of the Renewed Regulatory Framework for Electricity. The KWCG Working Group is comprised of members from the Ontario Power Authority (OPA), Hydro One Networks Inc. (Hydro One), the Independent Electricity System Operator (IESO) and local distribution companies (LDCs).

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

In the course of developing a regional plan for the KWCG area, the Working Group identified certain near- and medium-term supply capacity and other reliability needs to be addressed. The purpose of this evidence is to explain those needs and to recommend solutions – i.e., planned conservation and existing and committed distributed generation, along with transmission reinforcements – to address them. Based on expected growth in electricity demand in the KWCG area, these recommended solutions will provide a significant improvement to the reliability of electricity supply. They will also defer the potential need for additional major infrastructure (such as new transmission or large generation) in the area to beyond the study horizon, and will provide time to explore opportunities for increased cost effective conservation, distributed generation, and transmission investments (such as switching facilities). Monitoring of growth in electricity demand, as well as the achievement of conservation and distributed generation in the KWCG area will also be key components of ongoing electricity planning in the region.

3 Background

3.1 Kitchener-Waterloo-Cambridge-Guelph Area Population and Electricity Demand

The KWCG area is located to the west of the greater Toronto area in southwestern Ontario. It is a growing community with an estimated population of over 625,000 people.[1] The region includes the municipalities of Kitchener, Waterloo, Cambridge and Guelph, as well as portions of Perth and Wellington counties. In 2011, the Region of Waterloo[2] (which does not include Guelph) was Canada's 13th and Ontario's 7th largest urban centre[3]. The region was also noted as one of Ontario's Places to Grow.[4] The area's electricity demand is a mix of residential, commercial and industrial loads, encompassing diverse economic activities ranging from educational institutions to automobile manufacturing.

A large part of the area's electricity supply is serviced by four LDCs: Kitchener Wilmot Hydro, Waterloo North Hydro, Cambridge & North Dumfries Hydro and Guelph Hydro Electric

---

[1] 2011 Statistics Canada

[2] Waterloo Region contains the cities of Kitchener, Waterloo, and Cambridge, as well as the Townships of North Dumfries, Wellesley, Wilmot and Woolwich

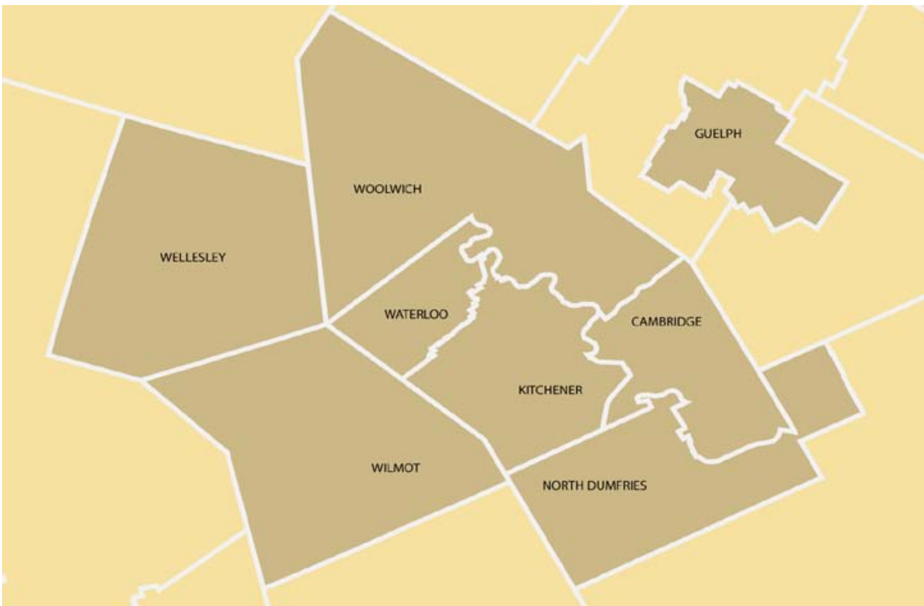
[3] 2011 Statistics Canada

[4] Ontario Ministry of Infrastructure, Places to Grow

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

Systems. Figure 1 highlights, in dark brown, the area served by these four KWCG LDCs. Hydro One Distribution generally provides service to loads outside of these municipal areas (shown in light brown). Additionally, there are three directly-connected industrial customers in the area served by Hydro One Transmission.

Figure 1: The KWCG Area



In the summer of 2012 the demand for electricity in the KWCG area peaked at over 1,400 MW. Of this, the KWCG LDCs served approximately 1,300 MW: Kitchener Wilmot Hydro served approximately 380 MW, Waterloo North Hydro approximately 290 MW, Cambridge & North Dumfries Hydro approximately 290 MW, Guelph Hydro Electric Systems approximately 290 MW, and Hydro One Distribution approximately 60 MW. While the economic downturn in 2008 and 2009 impacted growth in the region, the demand for electricity recovered to pre-recession levels in the summer of 2010.

3.2 KWCG Area Generation and Transmission Facilities

There are no major sources of generation supply within the KWCG area. As a result, the area relies predominantly on the transmission system to deliver electricity to its customers. This system includes the 230 kV circuits between Detweiler TS (in Kitchener), Orangeville TS (in Orangeville), and Middleport TS (near Hamilton), as well as eight 115 kV circuits emanating from Detweiler TS and Burlington TS (in Burlington). High voltage autotransformers tie the

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

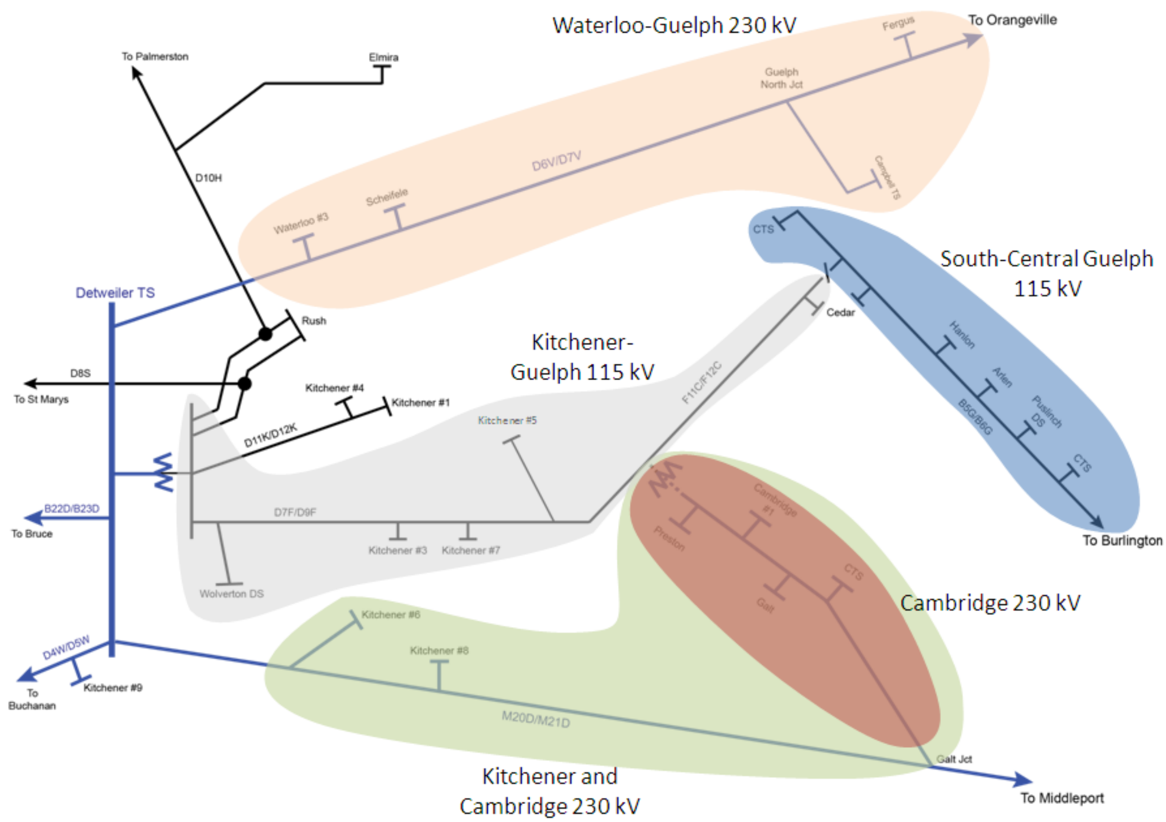
115 kV and 230 kV systems together at Detweiler TS, Burlington TS, and Preston TS (in Cambridge). For the purpose of this evidence, the transmission system in the KWCG area can be divided into the following subsystems:

- The South-Central Guelph 115 kV Subsystem (South-Central Guelph): customers supplied from Burlington TS via B5G/B6G;
- The Kitchener-Guelph 115 kV Subsystem (Kitchener-Guelph): customers supplied from Detweiler TS via D7F/D9F and F11C/F12C;
- The Waterloo-Guelph 230 kV Subsystem (Waterloo-Guelph): customers supplied from D6V/D7V;
- The Cambridge 230 kV Subsystem (Cambridge): customers supplied from M20D/M21D via the "Preston Tap"; and
- The Kitchener and Cambridge 230 kV Subsystem (Kitchener and Cambridge): customers supplied from M20D/M21D, including the Preston Tap.

Figure 2 provides a graphical representation of these five subsystems.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

Figure 2: KWCG Area Transmission Subsystems

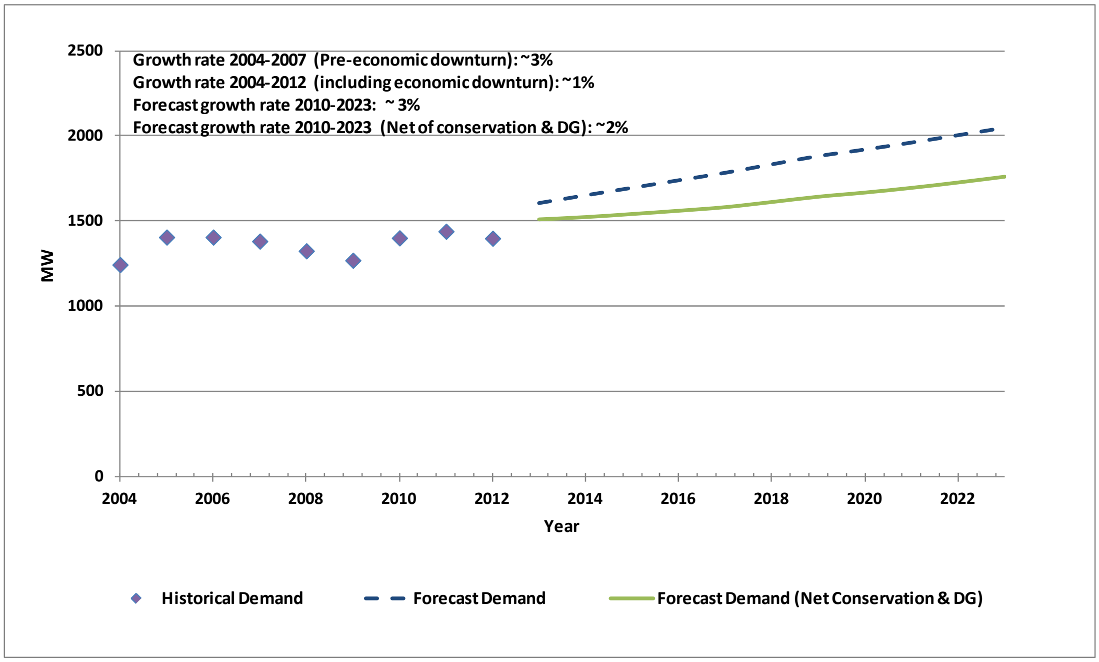


4 Historical and Forecast Electricity Demand

As previously mentioned, in the summer of 2012 the demand for electricity in the KWCG area peaked at over 1,400 MW. This represented an increase of approximately 10% from the low experienced in 2009 during the economic downturn. Despite the economic downturn, demand in the KWCG area has grown by approximately 1% per year between 2004 and 2012 (prior to the recession, growth was closer to 3%), and based on forecasts provided by the area LDCs, is expected to continue to grow at a pace of nearly 3% per year between 2010 and 2023. Figure 3 provides an overview of the historical and forecast future electricity demand in the KWCG area, inclusive of natural conservation. It also highlights the impacts of expected conservation and distributed generation resources, which are further discussed in Section 6.1 of this exhibit.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

Figure 3: Historical and Forecast Demand in the KWCG Area



The demand for electricity in the KWCG area is influenced by a number of factors such as economic, household and population growth. While these factors do not have a one-to-one correlation with electricity consumption, they do provide an indication of trends in electricity demand growth. Changes in the demand for electricity in the KWCG area that took place between 2004 and 2012 were directionally consistent with changes in these indicators. For example, growth in gross domestic product (GDP), one indication of economic growth, was nearly 2% per year throughout the 2004 to 2011 period in the Kitchener Region (an area defined by Statistics Canada that includes most of the KWCG area).[5] From 2004 to 2007, the period prior to the economic downturn, GDP growth in the area averaged over 3% annually. The direction of this GDP growth trend is consistent with the trend in historical electricity demand in the KWCG area.

Looking forward, GDP growth in the Kitchener Region is forecast to continue at a rate of about 2% annually, amongst the strongest in the province. Again this is in line with the expectation for growth in electricity demand in the KWCG area.

[5] Kitchener Region includes the municipalities of Kitchener, Cambridge, North Dumfries, Waterloo, and Woolwich.

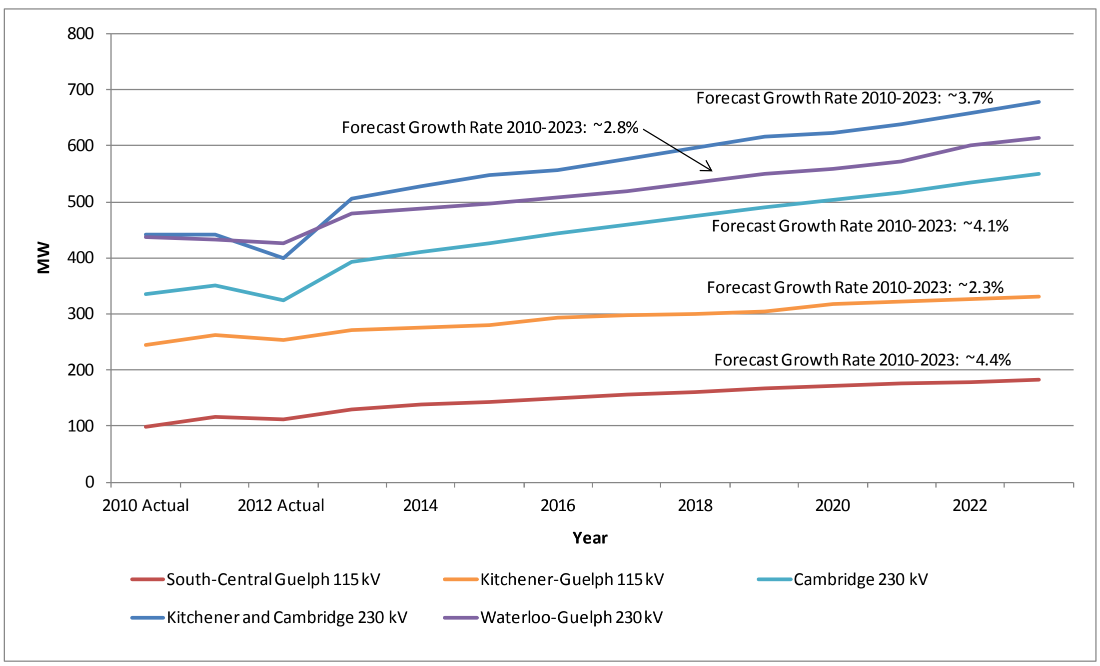
Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

Within the KWCG area, growth in electricity demand amongst the KWCG subsystems is expected to vary due to differences in the types and maturity of the loads they serve. The summer peak demand forecasts of the subsystems, as well as the remaining stations in the KWCG area, are shown in Table 1. Figure 4 provides a graphical representation of the subsystem forecasts.

Table 1: Demand Forecast for the South-Central Guelph, Kitchener-Guelph, Cambridge, and Kitchener and Cambridge Subsystems

(MW)	2010 Actual	2011 Actual	2012 Actual	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
South-Central Guelph 115 kV	99	117	112	131	139	144	150	155	161	167	172	175	179	182
Kitchener-Guelph 115 kV	244	262	254	272	275	281	294	297	301	304	317	321	326	330
Waterloo-Guelph 230 kV	436	433	425	480	489	498	507	518	535	550	560	571	602	615
Cambridge 230 kV	335	351	325	392	410	427	443	459	475	491	504	518	534	549
Kitchener and Cambridge 230 kV	442	442	401	506	528	547	557	577	596	616	622	639	659	678
Other Stations in the KWCG Area	184	190	211	216	221	227	233	237	242	247	251	256	242	247

Figure 4: Demand Forecast for the South-Central Guelph, Kitchener-Guelph, Cambridge, and, Kitchener and Cambridge Subsystems



As shown in Figure 4, the two subsystems with the highest growth expectations are the Cambridge 230 kV and South-Central Guelph 115 kV subsystems. This demand growth is driven by a number of factors including growth in the Region of Waterloo East Side Lands (a prime industrial area north of the 401 served by Cambridge and North Dumfries Hydro) and in the Hanlon Industrial Park (an area served by Guelph Hydro's newest transformer station Arlen MTS).

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

5 Needs in the KWCG Area

The IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC), (see Exhibit B, Tab 6, Schedule 3, Appendix A) establishes planning criteria and assumptions to be used for assessing the present and future reliability of Ontario's transmission system. Based on an application of these criteria, there are two near- and medium-term needs in the KWCG area: 1) needs relating to supply capacity to meet demand, and 2) needs relating to minimizing the impact of supply interruptions to customers. Each of these is explained below.

<u>Supply Capacity</u>

In accordance with ORTAC, the transmission system supplying a local area (i.e., subsystem) shall have sufficient capability under peak demand conditions to withstand specific outages prescribed by ORTAC while keeping voltages, line and equipment loading within applicable limits. More specifically, the maximum demand that can be supplied following the outage of a single element, as prescribed by ORTAC, is the "supply capacity" or the "load meeting capability" of the line or subsystem.[6] Due to the configuration of the transmission network serving an area, the load meeting capability may vary depending on growth in the surrounding region.

<u>Minimizing the Impact of Supply Interruptions</u>

In accordance with ORTAC, in the event of a major outage (for example a contingency on a double-circuit tower line resulting in the outage of both circuits), the transmission system shall be planned to minimize the impact of supply interruptions to customers both by reducing the number of customers affected by the outage and by restoring power to those affected within a reasonable timeframe. ORTAC therefore prescribes service interruption standards for certain sized load centres following such major transmission outages. Specifically, it provides that following a major outage no more than 600 MW of load will be interrupted, and that for load pockets less than 600 MW, load be restored within the following timeframes:

---

[6] ORTAC

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

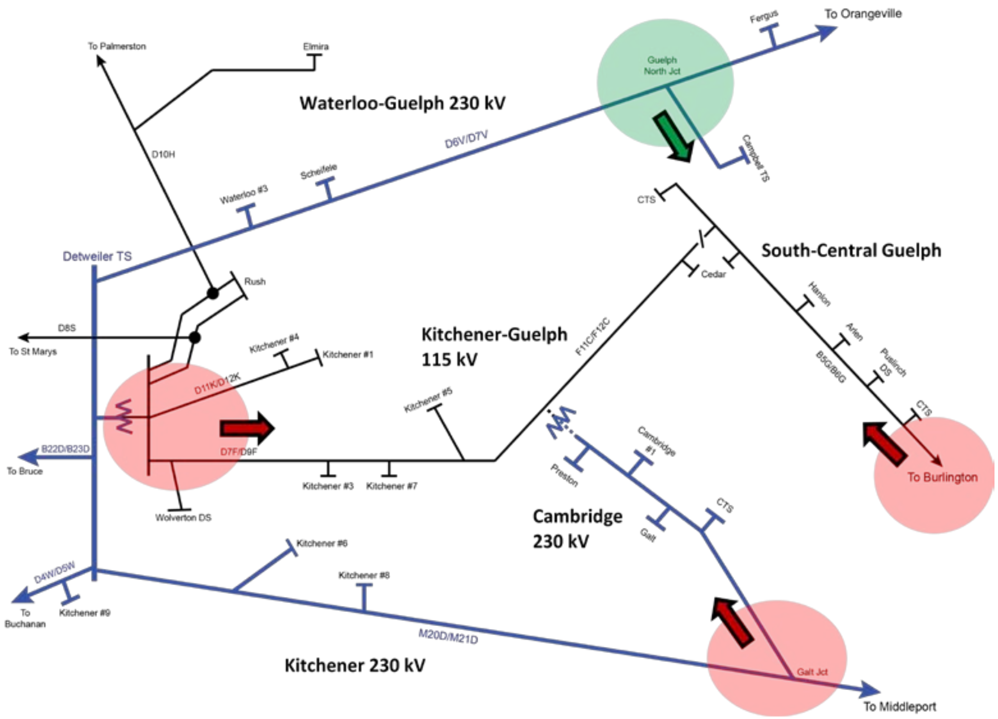
- all load lost in excess of 250 MW must be restored within half an hour;
- all load lost in excess of 150 MW must be restored within four hours; and finally
- all load lost in the area must be restored within eight hours.[7]

<u>Application of ORTAC Criteria</u>

Based on the application of the ORTAC criteria, three of the four sources of supply to the KWCG area (shown by the red circles in Figure 5) have reached, or are close to reaching, their load meeting capability. Additionally, a number of the subsystems are not meeting the service interruption criteria.

The following sections provide an overview of the capability of the existing KWCG transmission system and the need to increase supply capacity and to minimize the impact of supply interruptions to customers in the area.

Figure 5: Sources of Supply to the KWCG Area



---

[7] ORTAC

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

5.1 Need for Additional Supply Capacity

Over the next ten years, demand for electricity is expected to exceed the existing system's load meeting capability in the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems. Details of the needs in each of these three subsystems are explained below.

<u>South-Central Guelph 115 kV Subsystem</u>

Today, the double-circuit 115 kV transmission line (B5G/B6G) supplying South-Central Guelph from Burlington TS has a load meeting capability of approximately 100 MW. This limit is based on the voltage limitations of either the B5G or B6G circuit following the loss of the companion circuit. Based on the summer peak demand in the South-Central Guelph area, this supply capacity was exceeded in 2012 and is expected to remain beyond capacity over the next decade. Additional capacity is therefore required to meet current and growing electricity demand in the area. Until additional capacity is provided, operating measures (such as opening bus-tie breakers) will be required, resulting in a degradation of the level of supply security to the area.

<u>Kitchener-Guelph 115 kV Subsystem</u>

Today, the Kitchener-Guelph area is supplied by one double-circuit 115 kV transmission line (D7F/D9F and F11C/F12C) from Detweiler TS and supported by the existing 230/115 kV autotransformer at Preston TS. Following the loss of the D9F circuit, the remaining transmission supply to the area has a load meeting capability of approximately 260 MW depending on electricity demand in the surrounding area. This limit is based on thermal overloading of the D7F circuit from Detweiler TS. Based on the forecast electricity demand for the area, peak demand is expected to reach the 260 MW supply capacity limit in the summer of 2013. Additional capacity is therefore required to meet growing electricity demand in the area.

<u>Cambridge 230 kV Subsystem</u>

Today, the Cambridge area is supplied by one double-circuit 230 kV transmission line (the Preston Tap) tapped off of the main 230 kV transmission line (M20D/M21D) between Detweiler TS and Middleport TS. Following the loss of the M20D circuit, the companion circuit on the Preston Tap has a load meeting capability of approximately 375 MW. This limit is based on the thermal overloading of the M21D circuit between Galt Junction and Preston Junction in

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

Cambridge. Based on the forecast electricity demand for the area, peak demand is expected to reach the 375 MW supply capacity limit in the summer of 2013. Additional capacity is therefore required to meet growing electricity demand in the area.

5.2 Need to Minimize the Impact of Supply Interruptions to Customers

In addition to the above capacity needs, based on current and forecast demand, two subsystems within the KWCG area, namely the Waterloo-Guelph and Kitchener and Cambridge subsystems, currently fail to comply with the ORTAC service interruption criteria. Additionally, over the medium-term, supply to both of these areas is expected to exceed the maximum 600 MW load interruption level for a major outage as prescribed by ORTAC.

<u>Waterloo-Guelph 230 kV Subsystem</u>

Today, the Waterloo-Guelph subsystem is supplied by an approximately 77 km double-circuit 230 kV transmission line (D6V/D7V) between Detweiler TS and Orangeville TS. In the event of the loss of both the D6V and D7V circuits, all load supplied by this transmission line (which exceeded 400 MW in 2012) will be interrupted. The existing system lacks the capability to restore power to these customers in accordance with the ORTAC criteria which specifies that all load interrupted over 250 MW must be restored within 30 minutes. A major outage of this type took place on February 29th, 2012 when a forced outage on one of the D6V/D7V circuits, coupled with scheduled maintenance on the companion circuit, resulted in the interruption of electricity supply for roughly three hours to approximately 350 MW of customers in parts of the cities of Waterloo, Kitchener and Guelph.

Additionally, over the medium-term (by 2022), demand supplied by the D6V/D7V circuits is expected to exceed 600 MW. Reinforcement will be required to ensure that following a major outage to the D6V/D7V circuits, supply to this large load pocket will, as required by ORTAC, remain uninterrupted.

<u>Kitchener and Cambridge 230 kV Subsystem</u>

Today, the Kitchener and Cambridge subsystem is supplied by an approximately 82 km double-circuit 230 kV transmission line (M20D/M21D) between Detweiler TS and Middleport TS, including the Preston Tap. In the event of the loss of both the M20D and M21D circuits, all load

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

supplied by this transmission line (which was approximately 400 MW in 2012) will be interrupted. The existing 230/115 kV autotransformer and 230 kV disconnect switches at Preston TS allow power to be restored to only approximately 65 MW of demand within half an hour following a major outage. This is insufficient to meet the ORTAC criteria, which specifies that all load interrupted over 250 MW must be restored within 30 minutes. Prior to the installation of the autotransformer and disconnect switches at Preston TS, power could not be restored to any customers in the area in a timely manner. Such was the case in 2003 when the supply of power to parts of the City of Cambridge, the Township of North Dumfries and the City of Kitchener, totaling over 250 MW, was interrupted for nearly four hours.

Additionally, over the medium- term (by 2019), demand supplied by the M20D/M21D circuits is expected to exceed 600 MW. Reinforcement will be required to ensure that following a major outage to the M20D/M21D circuits, supply to this large load pocket will, as required by ORTAC, remain uninterrupted.

5.3 Summary of the Needs

The needs in the KWCG area identified above based on the application of the ORTAC are summarized in Table 2.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

Table 2: Summary of the Needs in the KWCG Area

Need Type	Subsystem	Need Description	Need Date
Capacity to Meet Demand	South-Central Guelph 115 kV	Loading on B5G/B6G exceeds load meeting capability	Now
	Kitchener-Guelph 115 kV	Loading on F11C/F12C exceeds load meeting capability	Now
	Cambridge 230 kV	Loading on M20D/M21D exceeds load meeting capability	Now
Minimize the Impact of Interruptions	Kitchener & Cambridge 230 kV	M20D/M21D does not comply with the ORTAC service interruption criteria	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: 2019
	Waterloo-Guelph 230 kV	D6V/D7V does not comply with the ORTAC service interruption criteria	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: 2022

6 Integrated Solutions to Address the Needs in the KWCG Area

In considering potential solutions for addressing the needs of the KWCG area, the OPA first considered conservation and distributed generation. These options reduce electricity demand and have the potential to negate or defer the need for investment in large-scale generation or transmission infrastructure. The OPA then considered large-scale generation or transmission infrastructure to meet any remaining needs in the area.

6.1 Conservation and Distributed Generation Options

6.1.1 Conservation

Conservation means reducing or shifting the consumption of and/or the demand for electricity. Such reductions or shifting help support the ability of the existing electricity system to meet growing electricity demand.

In February 2011, the Minister of Energy established conservation targets for Ontario over the next 20 years: 4,550 MW of peak demand reduction by 2015, increasing to 7,100 MW by 2030. Included in these targets is a peak demand reduction of 1,330 MW to be achieved by 2014 by Ontario's LDCs. These goals are aggressive, and large load centres, such as the KWCG area, are expected to be key contributors to ensuring Ontario's peak demand reduction targets can be met.

Based on an allocation of the provincial targets, nearly 270 MW in peak demand reduction is expected from conservation achievement within the KWCG area by 2023. Within the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems specifically, the planned peak demand reduction from conservation efforts by 2023 is over 130 MW. This planned conservation is expected to be achieved through a combination of peak demand savings resulting from province-wide conservation and demand management programs, improved building codes and equipment standards, and customer response to time-of-use pricing. These savings have an estimated delivery cost of $65 million, based on an allocation of forecast expenditures for provincial conservation programs. This planned conservation reduction is expected to off-set nearly 35% of the forecast load growth in these subsystems (on aggregate) between 2010 and 2023, and will contribute to meeting the KWCG area's capacity needs as shown in Table 4 below.

While conservation can be an effective means of addressing capacity needs, conservation cannot aid in the restoration of power to customers following a major transmission outage, and therefore cannot resolve the KWCG area's restoration needs.

Planned conservation efforts are important contributors to the reliable supply of electricity to the KWCG area, however further solutions will be needed to fully address the area's electricity needs; a capacity gap of nearly 70 MW remains in 2016, growing to nearly 200 MW by 2023, in

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

the South-Central Guelph, Kitchener-Guelph, and Cambridge subsystems. Based on the OPA's experience with conservation programs, the amount of planned conservation forecasted for the region, and the immediate nature of the needs, it is the OPA's view that additional conservation is not a feasible means of addressing the KWCG area's near- and medium-term needs as shown in Table 4. The OPA will continue to monitor conservation program uptake and success in the KWCG area, and look for opportunities for further cost effective conservation to maintain a reliable supply of electricity to the area over the longer-term.

6.1.2 Distributed Generation

Distributed generation is small-scale generation sited close to load centres; as such, it helps supply local energy needs while at the same time contributing to meeting provincial demand. Along with other OPA procurement processes, the introduction of the Green Energy and Green Economy Act, and the associated development of the Feed-In Tariff (FIT) program, has encouraged the development of distributed generation resources in Ontario. These procurements take into consideration the system need for generation as well as cost.

Within the KWCG area, nearly 150 MW of distribution and transmission connected renewable generation has been contracted through the FIT program and previous procurements (such as the Renewable Standard Offer Program), and is expected to come into service by the summer of 2016. This generation is spread throughout the KWCG area, with the majority located in the area north of Elmira and around Fergus TS. Additionally, some small-scale generation, such as Combined Heat and Power, totaling nearly 10 MW of installed capacity is in operation in the region.

It should be noted that distributed generation resources are not always available at the time of system peak, in particular, intermittent renewable generation resources such as wind and solar. The full installed capacity of these facilities therefore cannot be relied upon to meet the KWCG area's electricity needs. The OPA estimates that the existing and contracted distributed generation resources in the KWCG area will contribute approximately 35 MW of effective

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

capacity to meeting area peak demand.[8] Of this, approximately 1 MW of effective capacity is located within the South-Central Guelph subsystem, 1 MW in the Kitchener-Guelph subsystem, and 2 MW within the Cambridge subsystem, representing an estimated capital investment of approximately $70 million in these areas. This generation will contribute to addressing the KWCG area's capacity needs.

While distributed generation can be an effective means of meeting capacity needs, its ability to help minimize the impact of major outages to customers is limited. For example, the specific connection point of the facility, the technical design specifications of the generator, and safety protocols on the electricity system, can impact the ability of a distribution connected generator to restore power to customers following a major transmission outage.

The existing and contracted distributed generation resources in the KWCG area are important contributors to maintaining a reliable supply of electricity, however further solutions will be needed to fully address the area's electricity needs. It is the OPA's view that additional distributed generation is not a feasible means of addressing the KWCG area's near- and medium-term needs. There is uncertainty associated with the development of further distributed generation facilities. With regards to renewable generation facilities, there is uncertainty related to local development interest and contract awards under the ongoing FIT program, as well as the siting and connection of facilities at the specific location in which they are needed. For non-renewable distributed generation facilities there is risk associated with the availability of future procurements, as well as the siting and connection of facilities at the specific location in which they are needed. Additionally, it is the OPA's view that further distributed generation resources are not a cost effective means for addressing the needs of the KWCG area, due to the robust load growth anticipated in the region combined with the relatively low cost of the recommended transmission reinforcement discussed in section 6.3 below. Distributed generation may be an effective option to meet an area's needs when low load growth is anticipated and/or the cost of the alternative solutions is high in comparison. The OPA will continue to monitor the uptake of

[8] Effective capacity is that portion of installed capacity that contributes at the time of system peak.

distributed generation in the KWCG area, and look for opportunities for further cost effective distributed generation to maintain a reliable supply of electricity to the area over the longer-term.

6.1.3 KWCG Area Electricity Demand Net of Conservation and Distributed Generation Resources, and Remaining Reliability Needs

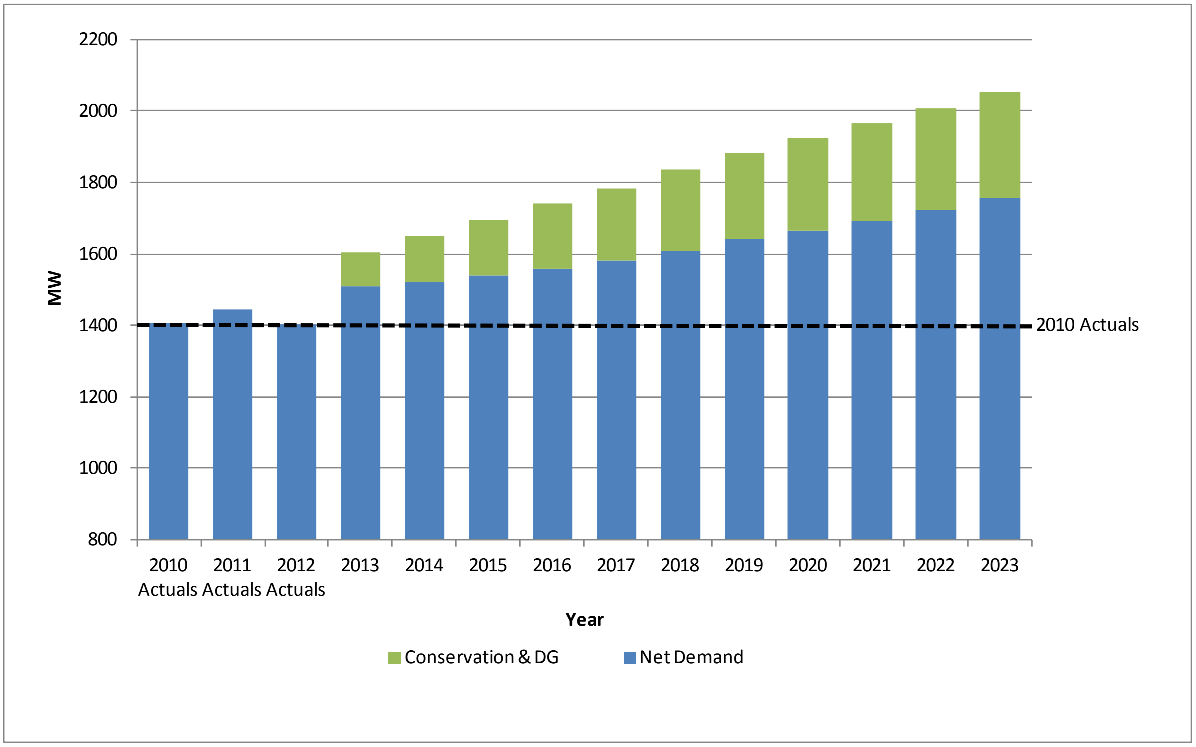
Conservation and distributed generation resources are important contributors to the integrated solution for addressing the needs of the KWCG area. The net summer peak demand in the KWCG area, after taking into account the contributions of conservation and distributed generation resources, is shown in Table 3 below. Additionally, the portion of growth in summer peak electricity demand forecast for the KWCG area met by conservation and distributed generation is shown in Figure 6.

Table 3: Demand Forecast for the South-Central Guelph, Kitchener-Guelph, Cambridge, and Kitchener and Cambridge Subsystems Net of Conservation and Distributed Generation

(MW)	2010 Actual	2011 Actual	2012 Actual	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
South-Central Guelph 115 kV	99	117	112	123	129	132	136	140	144	148	153	155	157	159
Kitchener-Guelph 115 kV	244	262	254	257	254	255	264	263	263	263	274	275	277	280
Waterloo-Guelph 230 kV	436	433	425	448	448	450	451	455	466	477	482	489	516	526
Cambridge 230 kV	335	351	325	372	383	393	404	415	426	438	447	458	471	484
Kitchener and Cambridge 230 kV	442	442	401	480	491	504	506	519	532	546	548	561	576	592
Other Stations in the KWCG Area	184	190	211	199	199	199	201	203	205	206	209	212	196	199

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

Figure 6: Forecasted Demand Growth in the KWCG Area met by Conservation and Distributed Generation Resources



Conservation and distributed generation resources alone are not sufficient to address the KWCG area's needs and will need to be supplemented by additional solutions. A summary of the remaining reliability needs in the area over the next ten years, after accounting for the contributions of conservation and distributed generation is provided in Table 4. This table also shows the contribution of conservation and distributed generation resources to deferring some of the near-term reliability needs of the KWCG area.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

Table 4: Summary of the Needs in the KWCG Area after the Contribution of Conservation and Distributed Generation Resources

Need Type	Subsystem	Need Description	Before Conservation & DG	After Conservation & DG
Capacity to Meet Demand	South-Central Guelph 115 kV	Loading on B5G/B6G exceeds load meeting capability	Now	Now
	Kitchener-Guelph 115 kV	Loading on F11C/F12C exceeds load meeting capability	Now	2019 (deferment of 6 years)
	Cambridge 230 kV	Loading on M20D/M21D exceeds load meeting capability	Now	2014 (deferment of 1 year)
Minimize the Impact of Interruptions	Kitchener & Cambridge 230 kV	M20D/M21D does not comply with the ORTAC service interruption criteria	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: 2019	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: Longer-term
	Waterloo-Guelph 230 kV	D6V/D7V does not comply with the ORTAC service interruption criteria	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: 2022	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: Longer-term

6.2 Generation Options

As noted in Table 4, even after taking into consideration the contribution of conservation and distributed generation, three of the KWCG subsystems (the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems) already exceed or are expected to exceed their supply capacity within the next ten years. Additionally, two subsystems (the Kitchener and Cambridge, and Waterloo-Guelph subsystems), currently do not comply with the ORTAC service interruption criteria. The development of large-scale generation can be an effective solution for meeting these needs.

In the KWCG area, a large-scale gas-fired generator (e.g., 200 MW plus) can only be accommodated on the 230 kV transmission system. The optimum location to site such a facility would be in the Cambridge area near Preston TS (a less central location would necessitate added transmission reinforcement costs and/or provide shorter-lasting benefit). This generation facility would meet the capacity and restoration needs of the Cambridge, and Kitchener and Cambridge subsystems, but would not address the capacity needs of the South-Central Guelph and Kitchener-Guelph subsystems, nor the restoration needs of the Waterloo-Guelph subsystem. These remaining reliability needs would necessitate significant transmission upgrades, or the installation of additional large-scale generation facilities. It is the OPA’s view that such an option is not cost effective when compared to the recommended transmission reinforcement discussed in section 6.3 below. Additionally, it could be challenging to site a large gas generation plant in the KWCG area within the time necessary to address the area’s needs.

The 115 kV transmission system within the KWCG area could accommodate a smaller gas-fired generator, e.g. 100 MW, in size. The optimum location to site such generation would be near Cedar TS. A centralized location near Cedar TS could meet the near and medium-term capacity needs of the South-Central Guelph and Kitchener-Guelph subsystems, however, additional facilities would be required to address the near-term capacity and restoration needs of the Cambridge, and Kitchener and Cambridge, and Waterloo-Guelph subsystems. Given the centralized location of Cedar TS, it would be difficult be difficult to site such a facility. If a site other than Cedar TS was to be selected multiple gas-fired generation facilities would be required to meet the capacity needs of South-Central Guelph and Kitchener-Guelph subsystems. It is the OPA’s view that smaller gas-fired generation is not cost effective when compared to the recommended transmission reinforcement discussed in section 6.3 below.

6.3 Transmission Options

Transmission reinforcements are a final option for addressing the remaining reliability needs of the KWCG area. Transmission options are discussed first in terms of their ability to meet the supply capacity needs of the KWCG area, followed by their ability to minimize the impact of

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

supply interruptions to customers. It is important to note that given the highly integrated nature of the KWCG area transmission system, transmission options identified as addressing reliability needs in one of the KWCG subsystems may also contribute to addressing reliability needs of the neighbouring subsystems.

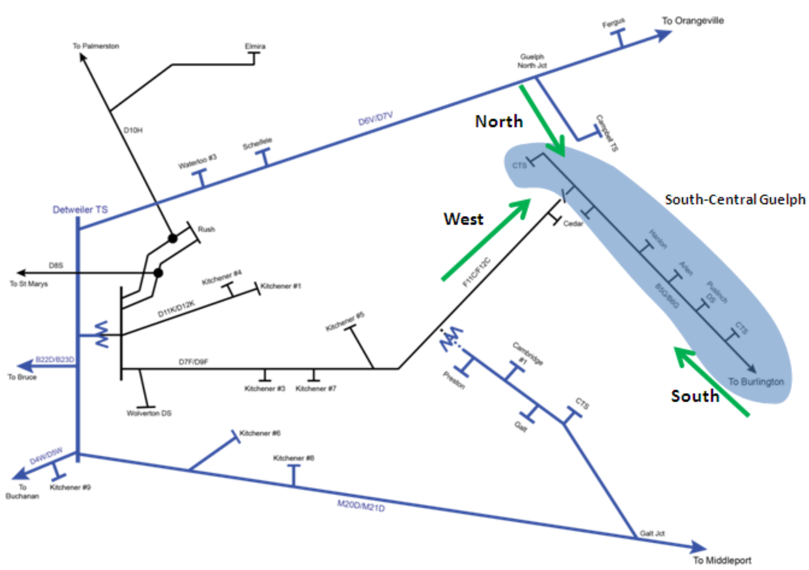
6.3.1 Transmission Options to Address Supply Capacity Needs

As noted in Table 4, three of the KWCG subsystems, namely the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems, already exceed or are expected to exceed their supply capacity. Transmission options for addressing these needs are discussed below.

Transmission Options for the South-Central Guelph Subsystem

The capacity needs of the South-Central Guelph subsystem can be addressed by reinforcing the transmission system from the West, South, or North as shown in Figure 7.

Figure 7: Transmission Reinforcement Options for South-Central Guelph



<u>Reinforcing supply from the South (Burlington TS)</u>

To improve the load meeting capability of the South-Central Guelph area, the existing 115 kV supply from Burlington TS could be reinforced. This could be accomplished by re-conductoring the existing B5G/B6G circuits (approximately 42 km in length) with a higher rated conductor (e.g. 1100 A), or by converting the existing B5G/B6G supply to 230 kV.

Given the age and design of the existing 115 kV transmission supply to South-Central Guelph, Hydro One has determined that it would not be feasible to reconductor the existing B5G/B6G circuits; instead, a new line would have to be constructed. Rebuilding the existing transmission line at either 115 kV or 230 kV would be complex, requiring bypass facilities to maintain supply to the area during construction. It would also be relatively expensive (over $200 million) given the significant distance between Burlington TS and Guelph and the number of stations that would potentially require conversion. Accordingly, this alternative was not considered further for meeting the capacity needs of South-Central Guelph.

Reinforcing supply from the West (Kitchener-Guelph Subsystem)

Similar to reinforcing supply to South-Central Guelph from the South, the existing 115 kV supply to the Kitchener-Guelph subsystem (the D7F/D9F and F11C/F12C circuits from Detweiler TS) could be reinforced through reconductoring or rebuilding. Due to the age and design of the existing F11C/F12C circuits, however, Hydro One has determined that it would not be feasible to reconductor this transmission line. Therefore, reinforcement from the west would have to be achieved through rebuilding the existing 115 kV transmission line between Detweiler TS and CGE Junction (near Cedar TS) to a higher rated 115 kV or 230 kV facility and installing switching facilities at Cedar TS. Similar to the southern option, rebuilding this line would be complex, would require bypass facilities to maintain supply during construction, and would be expensive (over $130 million) given the significant distance between Detweiler TS and CGE Junction (approximately 33 km) and the number of stations that would potentially require conversion. Accordingly, this alternative was not considered further for meeting the capacity needs of South-Central Guelph.

Reinforcing supply from the North (Waterloo-Guelph Subsystem)

Finally, additional transmission facilities could be constructed to reinforce the transmission supply to South-Central Guelph from the north. Upgrading the existing 115 kV transmission line between Campbell TS and CGE Junction to a double-circuit 230 kV transmission line, installing two new 230/115 kV autotransformers and four new 115 kV circuit breakers at Cedar TS, and transferring an existing directly connected customer in the area to the distribution system, would bring the northern 230 kV supply into the heart of Guelph.

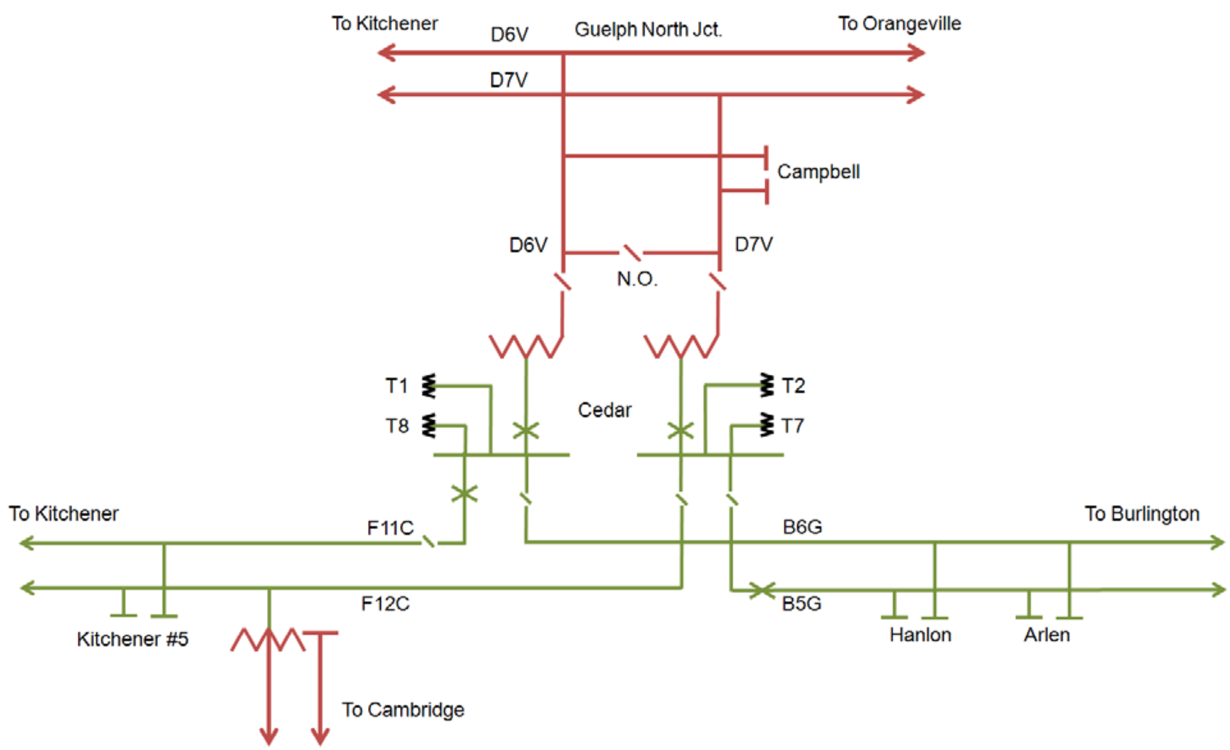
Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

At a cost of approximately $80 million, this alternative would provide a supply capacity increase sufficient to meet the needs of the South-Central Guelph area until beyond 2030, and could be completed by the end of 2015. While other options for reinforcing the transmission supply to South-Central Guelph from the north were considered (such as alternative switching arrangements, transferring a portion of the Cedar TS load to the 230 kV supply, and locating the two 230/115 kV autotransformers at a new site near Campbell TS), this option provides the greatest increase in supply capacity to South-Central Guelph, reduces the exposure of customers supplied by Cedar TS to supply outages, and provides better flexibility with respect to the end-of-life replacement of station equipment at both Cedar TS and Hanlon TS, which is anticipated to be required over the near- to medium-term. As noted below, it will also address the supply capacity needs of the Kitchener-Guelph subsystem. For these reasons, this is the preferred option for reinforcing the supply to South-Central Guelph.

The proposed system arrangement following the completion of recommended transmission reinforcement is shown in Figure 8.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

Figure 8: Proposed Arrangement for Reinforcing the Transmission Supply to South-Central Guelph from the North



Transmission Options for the Kitchener-Guelph Subsystem

The preferred solution for South-Central Guelph will make Cedar TS a strong source of supply within the KWCG area. In addition to addressing the capacity needs of South-Central Guelph, this strong source of supply will also be sufficient to satisfy the capacity needs of the Kitchener-Guelph subsystem until beyond 2030. Other alternatives to meet the capacity needs of the Kitchener-Guelph area (e.g. rebuilding of the existing 115 kV supply) would require incremental transmission investments, and are not recommended.

Transmission Options for the Cambridge Subsystem

The installation of a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support, along with the preferred solution for South-Central Guelph, would result in improvements to the supply capacity of the Cambridge and Kitchener-Guelph areas. Following the installation of these facilities, sufficient capacity would exist on the Kitchener-Guelph 115 kV subsystem to accommodate the addition of a future Cambridge & North Dumfries Hydro

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

station (approximately 100 MW in size). This would be sufficient to meet the capacity needs of the Cambridge area until the longer-term (2024), providing time to explore opportunities for further cost effective conservation and distributed generation, as well as transmission investments, such as voltage support and/or switching facilities. As further explained below, the addition of this second autotransformer will also partly address the supply restoration needs in the area. This work would be coordinated with the reinforcement of South-Central Guelph and could be completed by the end of 2015 at a cost of approximately $15 million to $25 million.

6.3.2 Preferred Option to Address Supply Capacity Needs

In summary, the preferred transmission options for addressing the near- and medium-term supply capacity needs of the KWCG area are:

- installing two new 230/115 kV autotransformers, four 115 kV breakers, and advancing the relocation of the existing Hydro One Distribution Operating Centre at Cedar TS ($52 million);
- rebuilding approximately 5 km of existing 115 kV transmission line between Campbell TS and CGE junction in Guelph with a double-circuit 230 kV transmission line, and transferring the existing directly connected customer in the area to the distribution system ($27.5 million); and
- installing a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support ($15 million to $25 million).

Together, these improvements will at a total estimated cost of approximately $95 million to $105 million meet the capacity needs of the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems until 2024 or beyond.

6.3.3 Options to Reduce the Impact of Supply Interruptions

As noted in Table 4, two of the KWCG subsystems, namely the Waterloo-Guelph, and Kitchener and Cambridge subsystems, are unable to restore power to customers in the area within half an hour following a major outage as prescribed by the ORTAC service interruption criteria. Additionally, over the longer-term, demand in these two areas is expected to exceed the maximum 600 MW load interruption level prescribed by ORTAC.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

These supply interruption needs can be partly addressed through the foregoing recommended capacity improvements, and the remaining supply interruption need can be satisfied through the following two transmission options 1) the implementation of load transfers following an outage, and/or 2) the installation of switching facilities, such as mid-span openers, motorized disconnect switches or circuit breakers. These potential options are evaluated below.

Options for the Waterloo-Guelph Subsystem

Load Transfers

One method of reducing supply interruptions to customers in the Waterloo-Guelph subsystem is to execute load transfers at the distribution level following a major transmission outage. KWCG area LDCs have identified little to no transfer capability of the loads in the area, and given the length of the D6V/D7V transmission line (about 77 km) and the amount of load served (over 400 MW), a number of load transfers, likely spanning significant distances (e.g. nearly 30 km between Orangeville TS and Fergus TS), would have to be implemented after each major transmission outage. It is the OPA's view that implementation of this option in order to comply with the ORTAC interruption criteria is not technically feasible. Accordingly, this alternative was not considered further as a means of reducing the impact of supply interruptions to customers in the Waterloo-Guelph subsystem.

Mid-Span Openers

Alternatively, installing mid-span openers at Guelph North Junction in the Township of Centre Wellington would facilitate the sectionalization of the D6V/D7V 230 kV circuits. Following a major transmission outage, the mid-span openers could be manually opened to isolate sections of the circuits and thus improve the restoration capability of the Waterloo-Guelph subsystem. However, because the mid-span openers are manually actuated, restoration capability could only be improved within 4 to 8 hours, which is insufficient to meet the 30 minute ORTAC requirement for the Waterloo-Guelph subsystem. For this reason, mid-span openers were not considered further as a means of reducing the impact of supply interruptions to customers in the Waterloo-Guelph area.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

Motorized Disconnect Switches

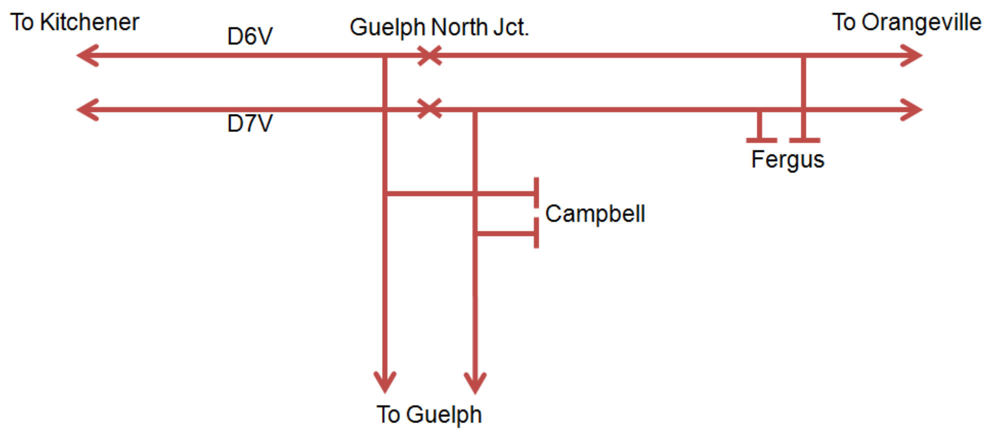
The installation of motorized disconnect switches at Guelph North Junction could also be used to facilitate the sectionalization of the D6V/D7V 230 kV circuits. These motorized switches could be operated remotely so that following a major transmission outage, load lost in excess of 250 MW in the Waterloo-Guelph area could be restored within 30 minutes. The estimated cost of this alternative is approximately $9 million to $12 million. While these facilities would address the near-term requirement for improved restoration capability, they would not address the longer-term need to prevent the interruption of demand in excess of 600 MW. To address this need, the installation of two 230 kV circuit breakers would be required in the longer-term at a cost of approximately $6 million to $15 million depending on the initial switching facilities installed. For the reasons noted below, this option was not preferred to installing new 230 kV circuit breakers at Guelph North Junction by 2015.

Circuit Breakers

Alternatively, two 230 kV circuit breakers could be installed at a new station (Inverhaugh SS) located at Guelph North Junction to facilitate sectionalization of the D6V/D7V circuits. The estimated cost of installing these breakers is approximately $16 million. This is roughly equivalent to the cost of installing motorized disconnect switches today and breakers in the longer-term. Compared to motorized disconnect switches, circuit breakers would reduce the exposure of customers in the area to supply outages by breaking the D6V/D7V circuits into three shorter sections (ranging from approximately 12 km to 35 km in length, compared to 77 km today). Circuit breakers also have a faster response time than motorized disconnect switches and would reduce the amount of time customers in the area would be without power following a major transmission outage. Finally, these facilities would address the future need to prevent the interruption of supply to customers in the area when demand on the D6V/D7V circuits exceeds 600 MW. For these reasons, the installation of two circuit breakers is the preferred option for reducing the impact of supply interruptions to customers in the Waterloo-Guelph subsystem. The proposed system arrangement after the installation of these breakers is shown in Figure 9.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

Figure 9: Proposed Transmission System Configuration after the Installation of two 230 kV Circuit Breakers at Guelph North Junction



These facilities, along with the refurbishment of the existing transmission line between Campbell TS and CGE Junction, and the installation of two 230/115 kV autotransformers and four 115 kV in-line breakers at Cedar TS, are referred to as the Guelph Area Transmission Refurbishment project, or GATR project.

Kitchener and Cambridge Subsystem

The preferred transmission reinforcements for meeting the capacity needs of the KWCG area would also increase the capability of the Kitchener and Cambridge subsystem to minimize the impact of major outages to customers in the area. With these reinforcements, the transmission system will have the capability to restore approximately 100 MW of load in the Cambridge area within 30 minutes. Additionally, approximately 100 MW of Cambridge area load will no longer be interrupted following the loss of the M20D/M21D circuits. This represents a significant improvement to the capability of the transmission system to minimize the impact of supply interruptions to customers, and is the preferred solution for contributing to meeting the restoration needs of the Kitchener and Cambridge area. This solution also defers the potential interruption of load in excess of 600 MW in the Kitchener and Cambridge area well into the longer-term.

The potential for further improvements to minimize the impact of major outages to customers in the Kitchener and Cambridge area will be investigated along with longer-term reliability planning for the region. Opportunities for further cost effective conservation and distributed

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

generation, as well as other investments, such as voltage support and/or switching facilities, will be investigated.

6.3.4 Preferred Options to Reduce the Impact of Supply Interruptions

In summary, the preferred options to reduce the impact of supply interruptions to customers in the KWCG area are to install two 230 kV circuit breakers at a new station located at Guelph North Junction (at an approximate cost of $16 million) and to install a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support (contingent on the development of the preferred capacity improvements in South-Central Guelph). The estimated cost of a second autotransformer at Preston TS (approximately $15 million to $25 million) is included in the overall estimated costs (approximately $95 million to $105 million) for the recommended capacity improvements. The potential for further improvements to minimize the impact of major outages to customers in the Kitchener and Cambridge area will be investigated along with longer-term reliability planning for the region.

7 Recommended Integrated Solution for the KWCG Area

The recommended solution for the needs of KWCG area is an integrated package composed of 1) conservation, 2) distributed generation resources, and 3) transmission reinforcements in the KWCG area (specifically the GATR project, and the installation of a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support).

Together, conservation and distributed generation resources are expected to off-set more than 35% of the forecast load growth in the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems between 2010 and 2023. These resources help to meet the existing reliability needs of the KWCG area, and also help to defer the need for longer-term investments in the region.

Transmission reinforcements are the final components of the integrated plan for the KWCG area. The total estimated cost of the transmission investments included in the integrated solution is approximately $110 million to $120 million: approximately $95 million for the GATR project, and approximately $15 million to $25 million for the installation of a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support. Project completion

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

is expected by the end of 2015, with development of the Preston TS autotransformer facilities being coordinated with completion of the GATR project.

It is the OPA's view that these facilities are a cost-effective and technically-effective solution for improving the supply capacity of the South-Central Guelph, Kitchener-Guelph, and Cambridge subsystems, and for reducing the impact of supply interruptions in Waterloo-Guelph, and Kitchener and Cambridge subsystems. Through longer-term planning for the KWCG area, opportunities for further cost effective conservation and distributed generation, as well as transmission investments will be investigated. Monitoring of growth in electricity demand and the achievement of conservation and distributed generation in the KWCG area, will also be key components of ongoing electricity planning in the region.

Ontario Power Authority
120 Adelaide Street West, Ste. 1600, Toronto, Ontario M5H 1T1 Tel 416 967-7474 Fax 416 967-1947 Toll Free 1-800-797-9604
info@powerauthority.on.ca www.powerauthority.on.ca

Kitchener-Waterloo-Cambridge-Guelph (KWCG)

Integrated Regional Resource Planning Report (IRRP) 2013

- DRAFT -

Kitchener-Waterloo-Cambridge Guelph
(KWCG) Working Group

Contents

1 Executive Summary

Near- and medium-term supply capacity and other reliability needs have been identified in the Kitchener-Waterloo-Cambridge-Guelph (KWCG) area. Specifically, three of the KWCG subsystems (the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems) are expected to exceed their supply capacity within the next ten years. Additionally, two subsystems (the Kitchener and Cambridge, and Waterloo-Guelph subsystems) do not comply with prescribed service interruption criteria. To address these needs, the OPA recommends an integrated package composed of 1) conservation, 2) distributed generation resources, and 3) transmission reinforcements in the KWCG area.

Conservation and distributed generation resources are important contributors to the integrated solution for addressing the needs of the KWCG area. Together, these resources are expected to off-set more than 35% of the forecast load growth in the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems between 2010 and 2023. By 2023 achievement from provincial conservation efforts within these subsystems is expected to reduce peak demand by over 130 MW at an estimated delivery cost of $65 million (based on an allocation of forecast expenditures for provincial conservation programs). Over the same time period, approximately 16 MW of distributed generation facilities are expected to come into service in South-Central Guelph, Kitchener-Guelph and Cambridge subsystems, representing a capital investment of approximately $70 million.

The transmission reinforcements recommended in the near-term include the Guelph Area Transmission Refurbishment (GATR) project, as well as a project to install a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support. The GATR project includes the installation of two new 230/115 kV autotransformers, four 115 kV circuit breakers, and the advancement of the relocation of the existing Hydro One Distribution Operating Centre at Cedar TS (approximately $52 million), rebuilding approximately 5 km of existing 115 kV double circuit transmission line between Campbell TS and CGE junction in Guelph to a 230 kV double circuit configuration (approximately $27.5 million), and installing two new 230 kV circuit breakers at a new station (Inverhaugh SS) at Guelph North Junction in Centre Wellington (approximately $16 million). Project completion for the GATR project is expected by the end of

2015. The installation of the Preston TS autotransformer facilities is a separate project that will be coordinated with completion of the GATR project and it is estimated to cost approximately $15 million to $25 million. Together these facilities will meet the near- and medium-term needs of the KWCG area, and substantially meet the KWCG area needs over the longer-term.

In anticipation for longer term growth in this area, the Working Group indicates the need to investigate opportunities for further cost effective conservation and distributed generation, as well as transmission investments. Monitoring of growth in electricity demand and the achievement of conservation and distributed generation in the KWCG area, will also be key components of on-going electricity planning in the region. The needs and the options in the longer term will be reviewed in subsequent KWCG regional planning study.

2 Introduction

The Kitchener-Waterloo-Cambridge-Guelph (KWCG) area is one of the larger population and electrical demand centres in Ontario. The existing electrical facilities in the area serve a diverse range of commercial, industrial and residential customers. The demand for electricity in the area is expected to grow substantially over the next 20 years, driven by population growth and strong economic activity. Much of the existing electricity infrastructure in the area is reaching capacity and therefore plans for future conservation, distributed generation and electricity infrastructure expansion and investment need to be developed and, as necessary, implemented in order to maintain a reliable supply of electricity to the area.

Planning to meet the electrical needs of a large area or region is done through a regional planning process that considers the multi-faceted needs of the region and seeks to address them through an integrated range of solutions. The plan takes into consideration, among other things, the electricity requirements, anticipated growth and existing electricity infrastructure. The outcome of the regional planning process is an integrated plan to guide electricity infrastructure, resource development and procurement decisions for the region. The plan's recommendations are typically organized into three timeframes: near-term (first 5 years), medium-term (5-10 years out) and longer-term (10-20 years out or longer). Solutions to address near-term and medium-term needs are presented as action items for immediate or early deployment, while solutions to address potential longer-term needs are identified along with the conditions that would trigger their implementation and the key development work required to maintain their viability. In this sense, regional plans are not static documents, but rather dynamic processes which evolve and are adapted as circumstances and conditions change.

2.1 Purpose and Scope of the Plan

The purpose of this report is to present the key findings and recommendations identified through the Integrated Regional Resource Planning ("IRRP") process for the KWCG area. In 2010, a working group (the "KWCG Working Group", or the "Working Group"), which comprised of members from the Ontario Power Authority (OPA), Hydro One Networks Inc. (Hydro One), the Independent Electricity System Operator (IESO) and local distribution companies (LDCs) in the KWCG area, was established to assess the reliability needs of the KWCG area, and to develop an integrated plan to address these needs. This regional planning process carried out by the KWCG Working Group is consistent with the IRRP process described by the Planning Process Working Group's ("PPWG") Report to the OEB as part of the Renewed Regulatory Framework for Electricity ("RRFE").

In the course of developing a regional plan for the KWCG area, the Working Group identified certain near- and medium-term supply capacity and other reliability needs to be addressed. The Working Group identified that these near-term needs were best met through a combination of conservation, local generation and transmission. Accordingly, a near-term transmission project was advanced to the transmitter led Section 92 and Environmental Assessment processes. This approach is consistent with the PPWG report to the Board that in certain cases, a 'wires' solution for a near -term transmission/distribution need may be advanced outside of the IRRP process.

This report, which covers a 20 -year planning horizon (2010-2030), will present and explain the near-, medium-, and long-term needs in the KWCG area, the preferred solutions for the near-and medium-term, and potential options for needs that may arise in the long-term. Consistent with IRRP process, an implementation and monitoring plan has been developed as part of the report to facilitate the implementation of the Working Group's recommendations. On a regular basis, the Working Group will review the needs of the KWCG area and updated this report as necessary.

3 Background

3.1 Kitchener-Waterloo-Cambridge-Guelph Area Population and Electricity Demand

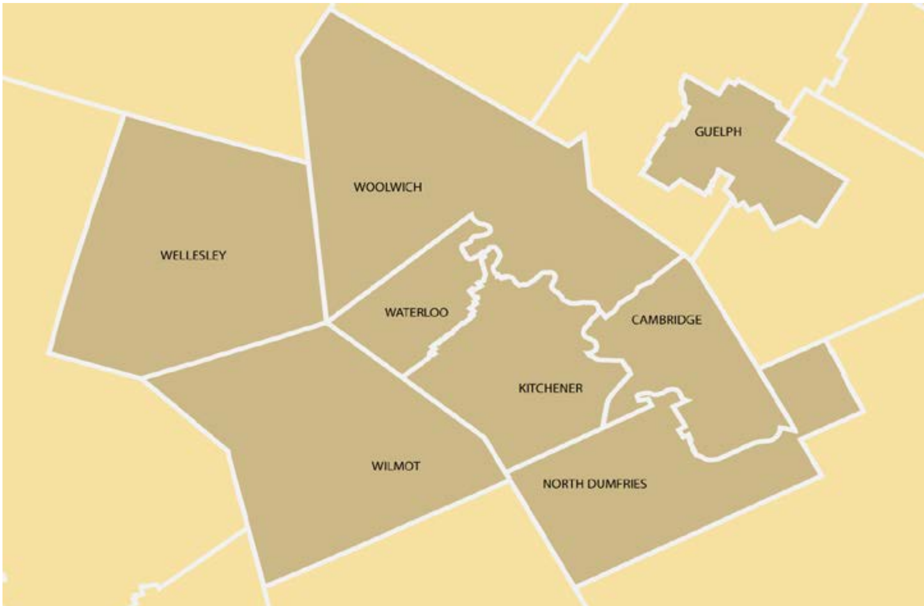
The KWCG area is located to the west of the greater Toronto area in southwestern Ontario. It is a growing community with an estimated population of over 625,000 people.[1] The region includes the municipalities of Kitchener, Waterloo, Cambridge and Guelph, as well as portions of Perth and Wellington counties. In 2011, the Region of Waterloo[2] (which does not include Guelph) was Canada's 13th and Ontario's 7th largest urban centre.[3] The region was also noted as one of Ontario's Places to Grow.[4] The area's electricity demand is a mix of residential, commercial and industrial loads, encompassing diverse economic activities ranging from educational institutions to automobile manufacturing.

A large part of the area's electricity supply is serviced by four LDCs: Kitchener Wilmot Hydro, Waterloo North Hydro, Cambridge & North Dumfries Hydro and Guelph Hydro Electric Systems. Figure 1 highlights, in dark brown, the area served by these four KWCG LDCs. Hydro One Distribution generally provides service to loads outside of these municipal areas (shown in light brown). Additionally, there are three directly-connected industrial customers in the area served by Hydro One Transmission.

---

[1] 2011 Statistics Canada
[2] Waterloo Region contains the cities of Kitchener, Waterloo, and Cambridge, as well as the Townships of North Dumfries, Wellesley, Wilmot and Woolwich
[3] 2011 Statistics Canada
[4] Ontario Ministry of Infrastructure, Places to Grow

Figure 1: The KWCG Area



In the summer of 2012 the demand for electricity in the KWCG area peaked at over 1,400 MW. Of this, the KWCG LDCs served approximately 1,300 MW: Kitchener Wilmot Hydro served approximately 380 MW, Waterloo North Hydro approximately 290 MW, Cambridge & North Dumfries Hydro approximately 290 MW, Guelph Hydro Electric Systems approximately 290 MW, and Hydro One Distribution approximately 60 MW. While the economic downturn in 2008 and 2009 impacted growth in the region, the demand for electricity recovered to pre-recession levels in the summer of 2010

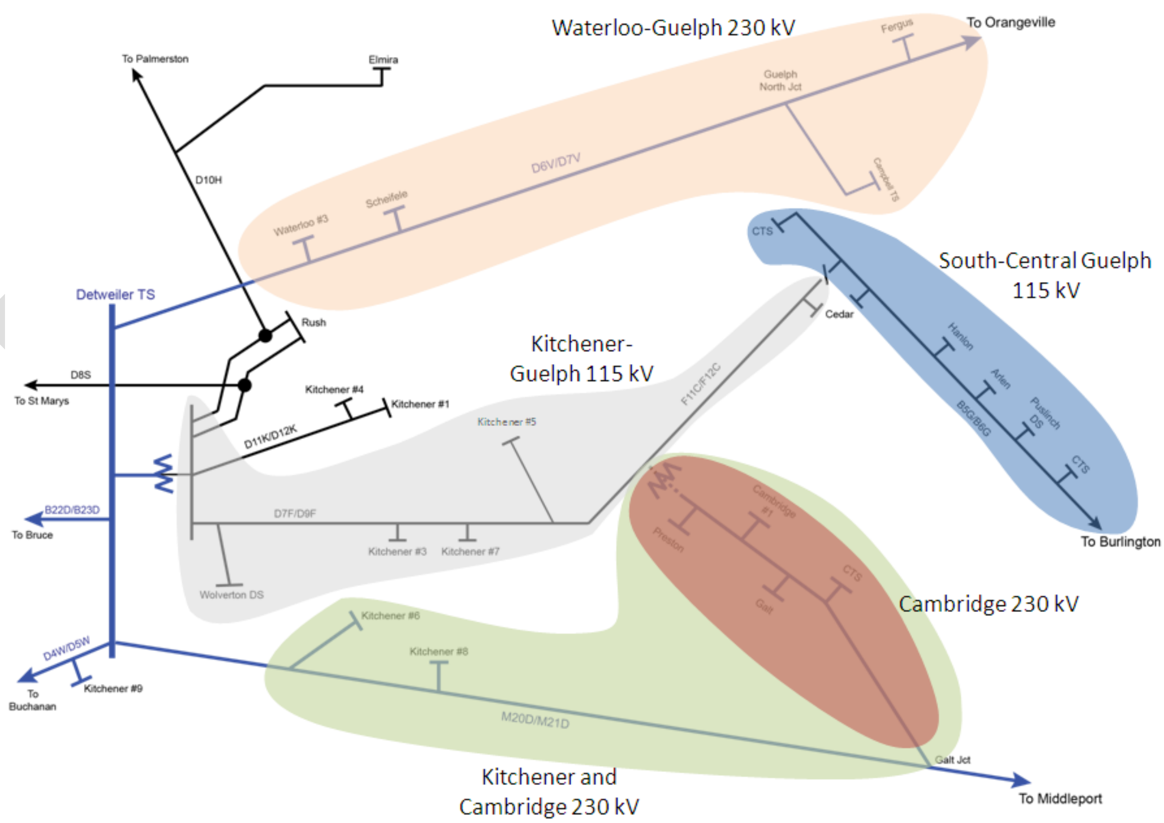
3.2 KWCG Area Generation and Transmission Facilities

There are no major sources of generation supply within the KWCG area. As a result, the area relies predominantly on the transmission system to deliver electricity to its customers. This system includes the 230 kV circuits between Detweiler TS (in Kitchener), Orangeville TS (in Orangeville), and Middleport TS (near Hamilton), as well as eight 115 kV circuits emanating from Detweiler TS and Burlington TS (in Burlington). High voltage autotransformers tie the 115 kV and 230 kV systems together at Detweiler TS, Burlington TS, and Preston TS (in Cambridge). For the KWCG Regional Planning Study, the transmission system in the KWCG area can be divided into the following subsystems:

- The South-Central Guelph 115 kV Subsystem (South-Central Guelph): customers supplied from Burlington TS via B5G/B6G;
- The Kitchener-Guelph 115 kV Subsystem (Kitchener-Guelph): customers supplied from Detweiler TS via D7F/D9F and F11C/F12C;
- The Waterloo-Guelph 230 kV Subsystem (Waterloo-Guelph): customers supplied from D6V/D7V;
- The Cambridge 230 kV Subsystem (Cambridge): customers supplied from M20D/M21D via the "Preston Tap"; and
- The Kitchener and Cambridge 230 kV Subsystem (Kitchener and Cambridge): customers supplied from M20D/M21D, including the Preston Tap.

Figure 2 provides a graphical representation of these five subsystems.

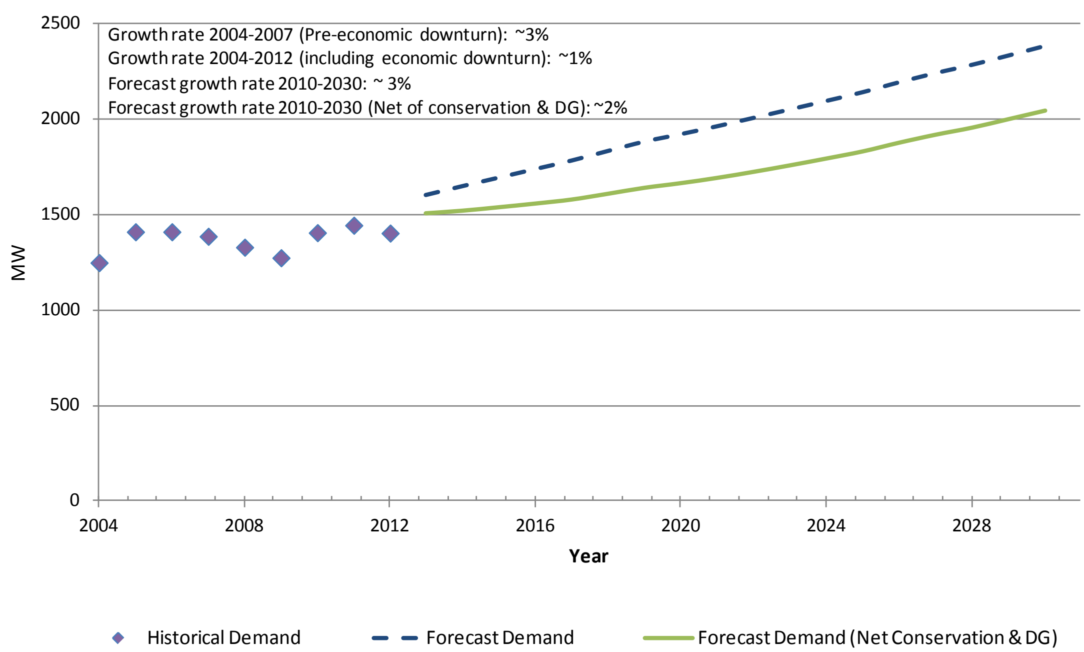
Figure 2: KWCG Area Transmission Subsystems



4 Historical and Forecast Electricity Demand

As previously mentioned, in the summer of 2012 the demand for electricity in the KWCG area peaked at over 1,400 MW. This represented an increase of approximately 10% from the low experienced in 2009 during the economic downturn. Despite the economic downturn, demand in the KWCG area has grown by approximately 1% per year between 2004 and 2012 (prior to the recession, growth was closer to 3%), and based on forecasts provided by the area LDCs, is expected to continue to grow at a pace of nearly 3% per year between 2010 and 2030. Figure 3 provides an overview of the historical and forecast future electricity demand in the KWCG area, inclusive of natural conservation. It also highlights the impacts of expected conservation and distributed generation resources, which are further discussed in Section 6.1.

Figure 3: Historical and Forecast Demand in the KWCG Area



The demand for electricity in the KWCG area is influenced by a number of factors such as economic, household and population growth. While these factors do not have a one-to-one correlation with electricity consumption, they do provide an indication of trends in electricity demand growth. Changes in the demand for electricity in the KWCG area that took place between 2004 and 2012 were directionally consistent with changes in these indicators. For example, growth in gross domestic product (GDP), one indication of economic growth, was nearly 2% per year throughout the 2004 to 2012 period in the Kitchener Region (an area defined by Statistics Canada that includes most of the KWCG area). [5] From 2004 to 2007, the period prior to the economic downturn, GDP growth in the area averaged over 3% annually. The direction of this GDP growth trend is consistent with the trend in historical electricity demand in the KWCG area.

Looking forward, GDP growth in the Kitchener Region is forecast to continue at a rate of about 2% annually, amongst the strongest in the province. Again this is in line with the expectation for growth in electricity demand in the KWCG area.

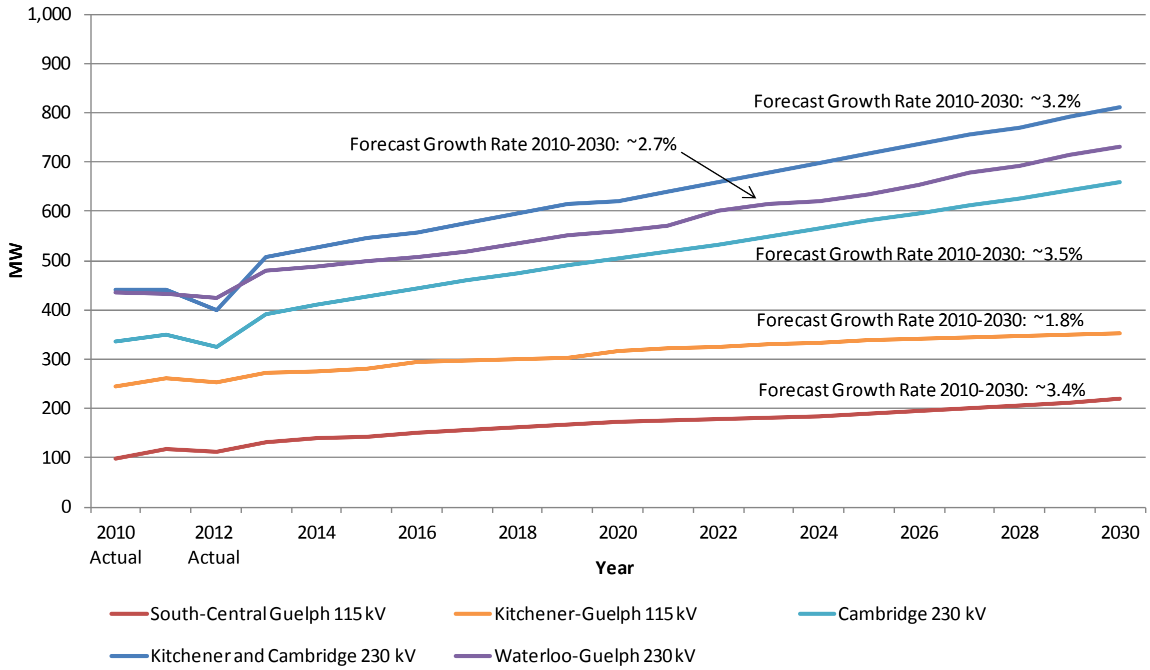
Within the KWCG area, growth in electricity demand amongst the KWCG subsystems is expected to vary due to differences in the types and maturity of the loads they serve. The summer peak demand forecasts of the subsystems, as well as the remaining stations in the KWCG area, are shown in Table 1. Figure 4 provides a graphical representation of the subsystem forecasts.

Table 1: Demand Forecast for the South-Central Guelph, Kitchener-Guelph, Cambridge, and Kitchener and Cambridge Subsystems

(MW)	2010 Actual	2011 Actual	2012 Actual	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
South-Central Guelph 115 kV	99	117	112	131	139	144	150	155	161	167	172	175	179	182	185	188	195	201	207	213	219
Kitchener-Guelph 115 kV	244	262	254	272	275	281	294	297	301	304	317	321	326	330	334	339	341	344	347	350	353
Waterloo-Guelph 230 kV	436	433	425	480	489	498	507	518	535	550	560	571	602	615	621	634	653	679	693	716	731
Cambridge 230 kV	335	351	325	392	410	427	443	459	475	491	504	518	534	549	565	581	597	614	625	642	659
Kitchener and Cambridge 230 kV	442	442	401	506	528	547	557	577	596	616	622	639	659	678	697	716	736	756	771	791	812
Other Stations in the KWCG Area	184	190	211	216	221	227	233	237	242	247	251	256	242	247	258	263	268	261	265	262	266

[5] Kitchener Region includes the municipalities of Kitchener, Cambridge, North Dumfries, Waterloo, and Woolwich.

Figure 4: Demand Forecast for the South-Central Guelph, Kitchener-Guelph, Cambridge, and, Kitchener and Cambridge Subsystems



As shown in Figure 4, the two subsystems with the highest growth expectations are the Cambridge 230 kV and South-Central Guelph 115 kV subsystems. This demand growth is driven by a number of factors including growth in the Region of Waterloo East Side Lands (a prime industrial area north of the 401 served by Cambridge and North Dumfries Hydro) and in the Hanlon Industrial Park (an area served by Guelph Hydro's newest transformer station Arlen MTS).

In addition to Arlen MTS, which came in-service in 2012, Cambridge and North Dumfries Hydro has indicated that two new transformer stations will be needed to meet growing demand in the Cambridge area over the study period. The first transformer station (Cambridge MTS #2) is expected to come in-service around 2018 and the second transformer station (Cambridge MTS #3) is expected to come in-service towards the end of the study period (beyond 2024). As well, Waterloo-North Hydro has forecasted two new transformer stations (Snider TS and Bradley TS) that will be connected to the Waterloo-Guelph 230kV system around 2018 and 2027.

5 Needs in the KWCG Area

The IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) (Appendix F.2), establishes planning criteria and assumptions to be used for assessing the present and future reliability of Ontario's transmission system. Based on an application of these criteria, there are two near- and medium-term needs in the KWCG area: 1) needs relating to supply capacity to meet demand, and 2) needs relating to minimizing the impact of supply interruptions to customers. Each of these is explained below.

<u>Supply Capacity</u>

In accordance with ORTAC, the transmission system supplying a local area (i.e., subsystem) shall have sufficient capability under peak demand conditions to withstand specific outages prescribed by ORTAC while keeping voltages, line and equipment loading within applicable limits. More specifically, the maximum demand that can be supplied following the outage of a single element, as prescribed by ORTAC, is the "supply capacity" or the "load meeting capability" of the line or subsystem.[6] Due to the configuration of the transmission network serving an area, the load meeting capability may vary depending on growth in the surrounding region.

<u>Minimizing the Impact of Supply Interruptions</u>

In accordance with ORTAC, in the event of a major outage (for example a contingency on a double-circuit tower line resulting in the outage of both circuits), the transmission system shall be planned to minimize the impact of supply interruptions to customers both by reducing the number of customers affected by the outage and by restoring power to those affected within a reasonable timeframe. ORTAC therefore prescribes service interruption standards for certain sized load centres following such major transmission outages. Specifically, it provides that following a major outage no more than 600 MW of load will be interrupted, and that for load pockets less than 600 MW, load be restored within the following timeframes:

[6] ORTAC

- all load lost in excess of 250 MW must be restored within half an hour;
- all load lost in excess of 150 MW must be restored within four hours; and finally
- all load lost in the area must be restored within eight hours.[7]

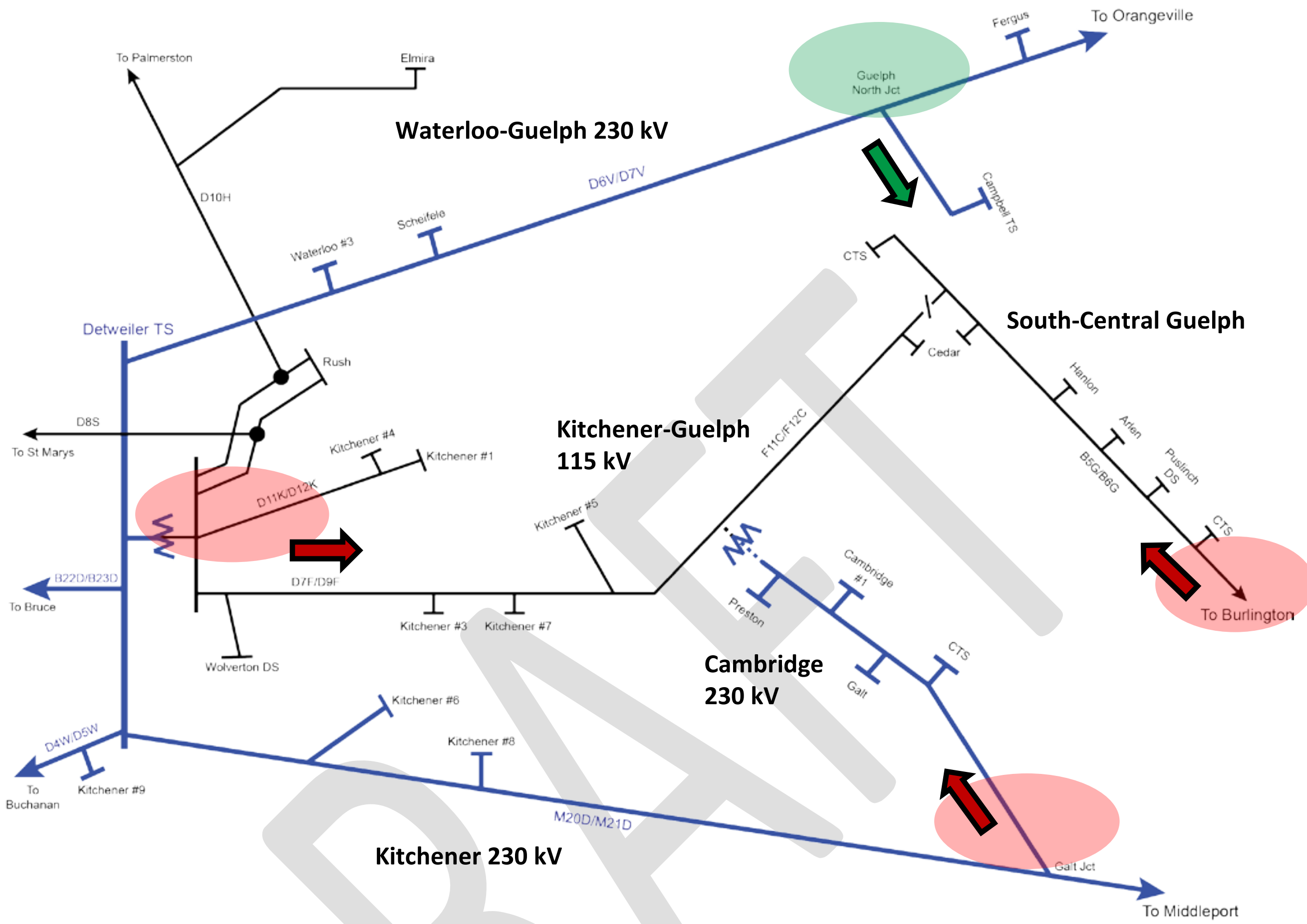
Application of ORTAC Criteria

Based on the application of the ORTAC criteria, three of the four sources of supply to the KWCG area (shown by the red circles in Figure 5) have reached, or are close to reaching, their load meeting capability. Additionally, a number of the subsystems are not meeting the service interruption criteria.

The following sections provide an overview of the capability of the existing KWCG transmission system and the need to increase supply capacity and to minimize the impact of supply interruptions to customers in the area.

[7] ORTAC

Figure 5: Sources of Supply to the KWCG Area



5.1 Need for Additional Supply Capacity

Over the next ten years, demand for electricity is expected to exceed the existing system's load meeting capability in the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems. Details of the needs in each of these three subsystems.

<u>South-Central Guelph 115 kV Subsystem</u>

Today, the double-circuit 115 kV transmission line (B5G/B6G) supplying South-Central Guelph from Burlington TS has a load meeting capability of approximately 100 MW. This limit is based on the voltage limitations of either the B5G or B6G circuit following the loss of the companion circuit (See Appendix F.4 for detailed analysis). Based on the summer peak demand in the

South-Central Guelph area, this supply capacity was exceeded in 2012 and is expected to remain beyond capacity over the next decade. Additional capacity is therefore required to meet current and growing electricity demand in the area. Until additional capacity is provided, operating measures (such as opening bus-tie breakers) will be required, resulting in a degradation of the level of supply security to the area.

Kitchener-Guelph 115 kV Subsystem

Today, the Kitchener-Guelph area is supplied by one double-circuit 115 kV transmission line (D7F/D9F and F11C/F12C) from Detweiler TS and supported by the existing 230/115 kV autotransformer at Preston TS. Following the loss of the D9F circuit, the remaining transmission supply to the area has a load meeting capability of approximately 260 MW depending on electricity demand in the surrounding area. This limit is based on thermal overloading of the D7F circuit from Detweiler TS (See Appendix F.4 for detailed analysis). Based on the forecast electricity demand for the area, peak demand is expected to reach the 260 MW supply capacity limit in the summer of 2013. Additional capacity is therefore required to meet growing electricity demand in the area.

Cambridge 230 kV Subsystem

Today, the Cambridge area is supplied by one double-circuit 230 kV transmission line (the Preston Tap) tapped off of the main 230 kV transmission line (M20D/M21D) between Detweiler TS and Middleport TS. Following the loss of the M20D circuit, the companion circuit on the Preston Tap has a load meeting capability of approximately 375 MW. This limit is based on the thermal overloading of the M21D circuit between Galt Junction and Preston Junction in Cambridge (See Appendix F.4 for detailed analysis). Based on the forecast electricity demand for the area, peak demand is expected to reach the 375 MW supply capacity limit in the summer of 2013. Additional capacity is therefore required to meet growing electricity demand and to supply the Cambridge and North Dumfries Hydro's new transformer station (Cambridge MTS #2) in 2018.

5.2 Need to Minimize the Impact of Supply Interruptions to Customers

In addition to the above capacity needs, based on current and forecast demand, two subsystems within the KWCG area, namely the Waterloo-Guelph and Kitchener and Cambridge subsystems, currently fail to comply with the ORTAC service interruption criteria. Additionally, over the medium-term, supply to both of these areas is expected to exceed the maximum 600 MW load interruption level for a major outage as prescribed by ORTAC.

Waterloo-Guelph 230 kV Subsystem

Today, the Waterloo-Guelph subsystem is supplied by an approximately 77 km double-circuit 230 kV transmission line (D6V/D7V) between Detweiler TS and Orangeville TS. In the event of the loss of both the D6V and D7V circuits, all load supplied by this transmission line (which exceeded 400 MW in 2012) will be interrupted. The existing system lacks the capability to restore power to these customers in accordance with the ORTAC criteria which specifies that all load interrupted over 250 MW must be restored within 30 minutes. A major outage of this type took place on February 29th, 2012 when a forced outage on one of the D6V/D7V circuits, coupled with scheduled maintenance on the companion circuit, resulted in the interruption of electricity supply for roughly three hours to approximately 350 MW of customers in parts of the cities of Waterloo, Kitchener and Guelph.

Additionally, over the medium-term (by 2022), with two new transformer stations (Snider TS and Bradley TS) coming into service in the Waterloo area in 2018 and 2027, demand supplied by the D6V/D7V circuits is expected to exceed 600 MW. Reinforcement will be required to ensure that following a major outage to the D6V/D7V circuits, supply to this large load pocket will, as required by ORTAC, remain uninterrupted.

Kitchener and Cambridge 230 kV Subsystem

Today, the Kitchener and Cambridge subsystem is supplied by an approximately 82 km double-circuit 230 kV transmission line (M20D/M21D) between Detweiler TS and Middleport TS, including the Preston Tap. In the event of the loss of both the M20D and M21D circuits, all load supplied by this transmission line (which was approximately 400 MW in 2012) will be interrupted. The existing 230/115 kV autotransformer and 230 kV disconnect switches at Preston TS allow power to be restored to only approximately 65 MW of demand within half an hour following a major outage (See Appendix F.5 for detailed analysis). This is insufficient to meet the ORTAC criteria, which specifies that all load interrupted over 250 MW must be restored within 30 minutes. Prior to the installation of the autotransformer and disconnect switches at Preston TS, power could not be restored to any customers in the area in a timely manner. Such was the case in 2003 when the supply of power to parts of the City of Cambridge, the Township of North Dumfries and the City of Kitchener, totaling over 250 MW, was interrupted for nearly four hours.

Additionally, over the medium- term (by 2019), if the first new transformer station in the Cambridge area (Cambridge MTS #2) is connect to the Kitchener and Cambridge 230 kV subsystem, demand supplied by the M20D/M21D circuits is expected to exceed 600 MW. Reinforcement will be required to ensure that following a major outage to the M20D/M21D circuits, supply to this large load pocket will, as required by ORTAC, remain uninterrupted.

5.3 Summary of the Needs

The needs in the KWCG area identified above based on the application of the ORTAC are summarized in Table 2.

Table 2: Summary of the Needs in the KWCG Area

Need Type	Subsystem	Need Description	Need Date
Capacity to Meet Demand	South-Central Guelph 115 kV	Loading on B5G/B6G exceeds load meeting capability	Now
	Kitchener-Guelph 115 kV	Loading on F11C/F12C exceeds load meeting capability	Now
	Cambridge 230 kV	Loading on M20D/M21D exceeds load meeting capability	Now
Minimize the Impact of Interruptions	Kitchener & Cambridge 230 kV	M20D/M21D does not comply with the ORTAC service interruption criteria	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: 2019
	Waterloo-Guelph 230 kV	D6V/D7V does not comply with the ORTAC service interruption criteria	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: 2022

5.4 Impact of Higher and Lower Demand Scenarios

In addition to the reference demand forecast, the Working Group has developed higher and lower demand scenarios to account for potential demand variation related to conservation and distributed generation uptake, economic development, and population growth in the KWCG area. The details related to the higher and lower growth demand scenarios can be found in Appendix B.5.

Given that the majority of the needs in the KWCG area exist today, a higher demand scenario does not significantly impact the needs in the near- and medium-term. While lower than expected demand growth may defer the supply capacity in the Kitchener-Guelph 115kV in the longer term, the majority of the needs in the KWCG area will need to be addressed in the near-to-medium timeframe under the lower demand scenario. Table 3 summarizes the impact of the higher and lower demand scenarios.

Table 3: Impact of Higher and Lower Demand Scenario

Need Type	Subsystem	Need Description	Reference	Lower Demand Scenario	Higher Demand Scenario
Capacity to Meet Demand	South-Central Guelph 115 kV	Loading on B5G/B6G exceeds load meeting capability	Now	Now	Now
	Kitchener-Guelph 115 kV	Loading on F11C/F12C exceeds load meeting capability	Now	Beyond 2030	Now
	Cambridge 230 kV	Loading on M20D/M21D exceeds load meeting capability	Now	2016	Now
Minimize the Impact of Interruptions	Kitchener & Cambridge 230 kV	M20D/M21D does not comply with the ORTAC service interruption criteria	Restoration of load > 250 MW: Now	Restoration of load > 250 MW: Now	Restoration of load > 250 MW: Now
			Exceeds Max Allowable Load Loss of 600 MW: 2019	Exceeds Max Allowable Load Loss of 600 MW: Beyond 2030	Exceeds Max Allowable Load Loss of 600 MW: 2020
	Waterloo-Guelph 230 kV	D6V/D7V does not comply with the ORTAC service interruption criteria	Restoration of load > 250 MW: Now	Restoration of load > 250 MW: Now	Restoration of load > 250 MW: Now
			Exceeds Max Allowable Load Loss of 600 MW: 2022	Exceeds Max Allowable Load Loss of 600 MW: Beyond 2030	Exceeds Max Allowable Load Loss of 600 MW: 2022

6 Integrated Solutions to Address the Near- and Medium-Term Needs in the KWCG Area

In considering potential solutions for addressing the needs of the KWCG area, the Working Group first considered conservation and distributed generation. These options reduce electricity demand and have the potential to negate or defer the need for investment in large-scale generation or transmission infrastructure. The Working Group then considered large-scale generation or transmission infrastructure to meet any remaining needs in the area.

6.1 Conservation and Distributed Generation Options

6.1.1 Conservation

Conservation means reducing or shifting the consumption of and/or the demand for electricity. Such reductions or shifting help support the ability of the existing electricity system to meet growing electricity demand.

In February 2011, the Minister of Energy established conservation targets for Ontario over the next 20 years: 4,550 MW of peak demand reduction by 2015, increasing to 7,100 MW by 2030. Included in these targets is a peak demand reduction of 1,330 MW to be achieved by 2014 by Ontario's LDCs. These goals are aggressive, and large load centres, such as the KWCG area, are expected to be key contributors to ensuring Ontario's peak demand reduction targets can be met.

Based on an allocation of the provincial targets, nearly 270 MW in peak demand reduction is expected from conservation achievement within the KWCG area by 2023. Within the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems specifically, the planned peak demand reduction from conservation efforts by 2023 is over 130 MW. This planned conservation is expected to be achieved through a combination of peak demand savings resulting from province-wide conservation and demand management programs, improved building codes and equipment standards, and customer response to time-of-use pricing. These savings have an estimated delivery cost of $65 million, based on an allocation of forecast expenditures for provincial conservation programs. This planned conservation reduction is expected to off-set nearly 35% of the forecast load growth in these subsystems (on aggregate) between 2010 and

2023, and will contribute to meeting the KWCG area's capacity needs as shown in Table 5 below.

While conservation can be an effective means of addressing capacity needs, conservation cannot aid in the restoration of power to customers following a major transmission outage, and therefore cannot resolve the KWCG area's restoration needs.

Planned conservation efforts are important contributors to the reliable supply of electricity to the KWCG area, however further solutions will be needed to fully address the area's electricity needs; a capacity gap of nearly 70 MW remains in 2016, growing to nearly 200 MW by 2023, in the South-Central Guelph, Kitchener-Guelph, and Cambridge subsystems. Based on the OPA's experience with conservation programs, the amount of planned conservation forecasted for the region, and the immediate nature of the needs, the Working Group determined that additional conservation could not meet the near- and medium-term needs of the KWCG area. However, as discussed in Section 7, there may be opportunities to explore the potential for additional cost effective conservation to maintain a reliable supply of electricity to the KWCG area over the longer-term.

6.1.2 Distributed Generation

Distributed generation is small-scale generation sited close to load centres; as such, it helps supply local energy needs while at the same time contributing to meeting provincial demand. Along with other OPA procurement processes, the introduction of the Green Energy and Green Economy Act, and the associated development of the Feed-In Tariff (FIT) program, has encouraged the development of distributed generation resources in Ontario. These procurements take into consideration the system need for generation as well as cost.

Within the KWCG area, nearly 150 MW of distribution and transmission connected renewable generation has been contracted through the FIT program and previous procurements (such as the Renewable Standard Offer Program), and is expected to come into service by the summer of 2016. This generation is spread throughout the KWCG area, with the majority located in the area north of Elmira and around Fergus TS. Additionally, some small-scale generation, such as Combined Heat and Power, totaling nearly 10 MW of installed capacity is in operation in the region.

It should be noted that distributed generation resources are not always available at the time of system peak, in particular, intermittent renewable generation resources such as wind and solar. The full installed capacity of these facilities therefore cannot be relied upon to meet the KWCG area's electricity needs. The OPA estimates that the existing and contracted distributed generation resources in the KWCG area will contribute approximately 35 MW of effective capacity to meeting area peak demand.[8] Of this, approximately 1 MW of effective capacity is located within the South-Central Guelph subsystem, 1 MW in the Kitchener-Guelph subsystem, and 2 MW within the Cambridge subsystem, representing an estimated capital investment of approximately $70 million in these areas. This generation will contribute to addressing the KWCG area's capacity needs.

While distributed generation can be an effective means of meeting capacity needs, its ability to help minimize the impact of major outages to customers is limited. For example, the specific connection point of the facility, the technical design specifications of the generator, and safety protocols on the electricity system, can impact the ability of a distribution connected generator to restore power to customers following a major transmission outage.

The existing and contracted distributed generation resources in the KWCG area are important contributors to maintaining a reliable supply of electricity, however further solutions will be needed to fully address the area's electricity needs. The Working Group determined that additional distributed generation is not a feasible means of addressing the KWCG area's near- and medium-term needs. There is uncertainty associated with the development of further distributed generation facilities. With regards to renewable generation facilities, there is uncertainty related to local development interest and contract awards under the ongoing FIT program, as well as the siting and connection of facilities at the specific location in which they are needed. For non-renewable distributed generation facilities there is risk associated with the availability of future procurements, as well as the siting and connection of facilities at the specific location in which they are needed. Additionally, further distributed generation resources are not a cost effective means for addressing the needs of the KWCG area, due to the robust load growth anticipated in the region combined with the relatively low cost of the recommended transmission reinforcement discussed in Section 6.3 below. Distributed generation may be an

[8] Effective capacity is that portion of installed capacity that contributes at the time of system peak.

effective option to meet an area's needs when low load growth is anticipated and/or the cost of the alternative solutions is high in comparison (see Appendix D.3 for more details). Furthermore, as discussed in Section 7, there may be opportunities to explore the potential for additional cost effective distributed generation n to maintain a reliable supply of electricity to the KWCG area over the longer-term.

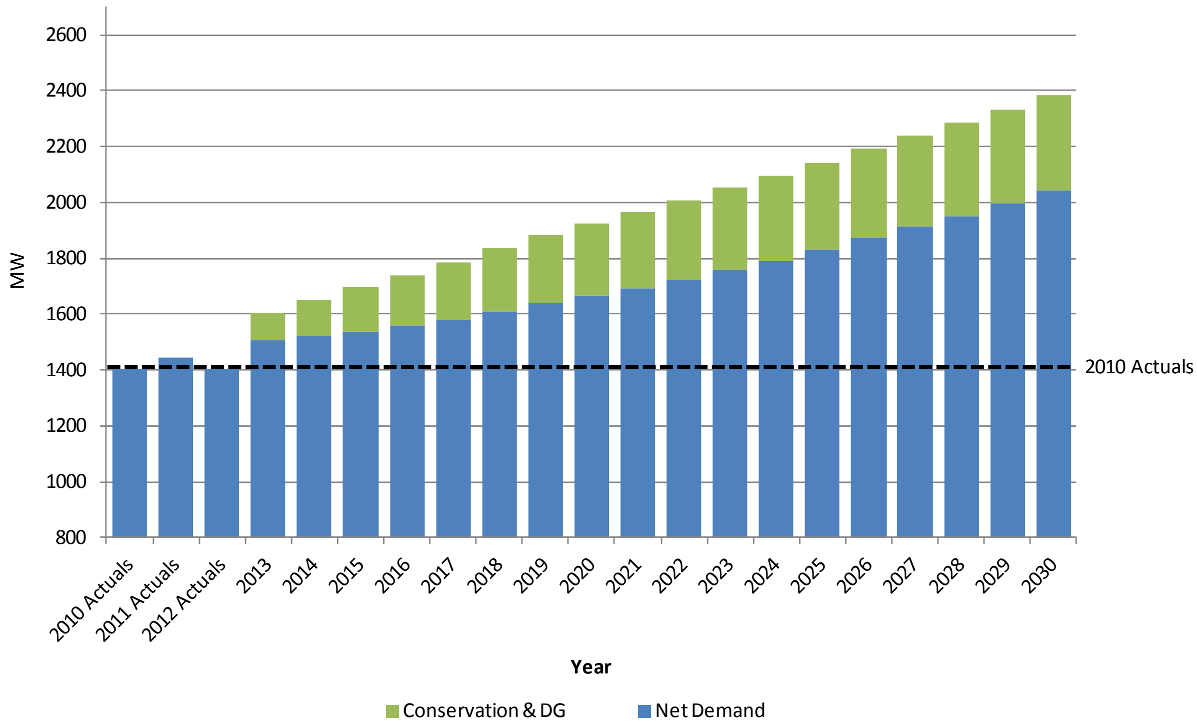
6.1.3 KWCG Area Electricity Demand Net of Conservation and Distributed Generation Resources, and Remaining Reliability Needs

Conservation and distributed generation resources are important contributors to the integrated solution for addressing the needs of the KWCG area. The net summer peak demand in the KWCG area, after taking into account the contributions of conservation and distributed generation resources, is shown in Table 4 below. Additionally, the portion of growth in summer peak electricity demand forecast for the KWCG area met by conservation and distributed generation is shown in Figure 6.

Table 4: Demand Forecast for the South-Central Guelph, Kitchener-Guelph, Cambridge, and Kitchener and Cambridge Subsystems Net of Conservation and Distributed Generation

(MW)	2010 Actual	2011 Actual	2012 Actual	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
South-Central Guelph 115 kV	99	117	112	123	129	132	136	140	144	148	153	155	157	159	162	165	170	176	181	187	193
Kitchener-Guelph 115 kV	244	262	254	257	254	255	264	263	263	263	274	275	277	280	282	285	287	289	290	292	294
Waterloo-Guelph 230 kV	436	433	425	448	448	450	451	455	466	477	482	489	516	526	530	541	557	582	594	616	629
Cambridge 230 kV	335	351	325	372	383	393	404	415	426	438	447	458	471	484	498	512	526	541	551	567	583
Kitchener and Cambridge 230 kV	442	442	401	480	491	504	506	519	532	546	548	561	576	592	609	626	643	661	674	693	712
Other Stations in the KWCG Area	184	190	211	199	199	199	201	203	205	206	209	212	196	199	210	213	217	209	212	208	212

Figure 6: Forecasted Demand Growth in the KWCG Area met by Conservation and Distributed Generation Resources



Conservation and distributed generation resources alone are not sufficient to address the KWCG area's needs and will need to be supplemented by additional solutions. A summary of the remaining reliability needs in the area over the next ten years, after accounting for the contributions of conservation and distributed generation is provided in Table 5. This table also shows the contribution of conservation and distributed generation resources to deferring some of the near-term reliability needs of the KWCG area.

Table 5: Summary of the Needs in the KWCG Area after the Contribution of Conservation and Distributed Generation Resources

Need Type	Subsystem	Need Description	Before Conservation & DG	After Conservation & DG
Capacity to Meet Demand	South-Central Guelph 115 kV	Loading on B5G/B6G exceeds load meeting capability	Now	Now
	Kitchener-Guelph 115 kV	Loading on F11C/F12C exceeds load meeting capability	Now	2019 (deferment of 6 years)
	Cambridge 230 kV	Loading on M20D/M21D exceeds load meeting capability	Now	2014 (deferment of 1 year)
Minimize the Impact of Interruptions	Kitchener & Cambridge 230 kV	M20D/M21D does not comply with the ORTAC service interruption criteria	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: 2019	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: 2024
	Waterloo-Guelph 230 kV	D6V/D7V does not comply with the ORTAC service interruption criteria	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: 2022	Restoration of load > 250 MW: Now Exceeds Max Allowable Load Loss of 600 MW: 2029

6.2 Generation Options

As noted in Table 5, even after taking into consideration the contribution of conservation and distributed generation, three of the KWCG subsystems (the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems) already exceed or are expected to exceed their supply capacity within the next ten years. Additionally, two subsystems (the Kitchener and Cambridge, and Waterloo-Guelph subsystems), currently do not comply with the ORTAC service interruption criteria. The development of large-scale generation can be an effective solution for meeting these needs.

In the KWCG area, a large-scale gas-fired generator (e.g., 200 MW plus) can only be accommodated on the 230 kV transmission system. The optimum location to site such a facility would be in the Cambridge area near Preston TS (a less central location would necessitate added transmission reinforcement costs and/or provide shorter-lasting benefit). This generation facility would meet the capacity and restoration needs of the Cambridge, and Kitchener and Cambridge subsystems, but would not address the capacity needs of the South-Central Guelph and Kitchener-Guelph subsystems, nor the restoration needs of the Waterloo-Guelph subsystem. These remaining reliability needs would necessitate significant transmission upgrades, or the installation of additional large-scale generation facilities. It is the Working Group's view that such an option is not cost effective when compared to the recommended transmission reinforcement discussed in Section 6.3 below. Additionally, it could be challenging to site a large gas generation plant in the KWCG area within the time necessary to address the area's needs (see Appendix D.3 for more details).

The 115 kV transmission system within the KWCG area could accommodate a smaller gas-fired generator, e.g. 100 MW, in size. The optimum location to site such generation would be near Cedar TS. A centralized location near Cedar TS could meet the near and medium-term capacity needs of the South-Central Guelph and Kitchener-Guelph subsystems, however, additional facilities would be required to address the near-term capacity and restoration needs of the Cambridge, and Kitchener and Cambridge, and Waterloo-Guelph subsystems. Given the centralized location of Cedar TS, it would be difficult to site such a facility. If a site other than Cedar TS was to be selected multiple gas-fired generation facilities would be required to meet the capacity needs of South-Central Guelph and Kitchener-Guelph subsystems. It is the Working Group's view that smaller gas-fired generation is not cost effective when compared to the recommended transmission reinforcement discussed in Section 6.3 below (see Appendix D.3 for more details).

6.3 Transmission Options

Transmission_reinforcements are a final option for addressing the remaining reliability needs of the KWCG area. Transmission options are discussed first in terms of their ability to meet the supply capacity needs of the KWCG area, followed by their ability to minimize the impact of supply interruptions to customers. It is important to note that given the highly integrated nature of the KWCG area transmission system, transmission options identified as addressing reliability needs in one of the KWCG subsystems may also contribute to addressing reliability needs of the neighbouring subsystems.

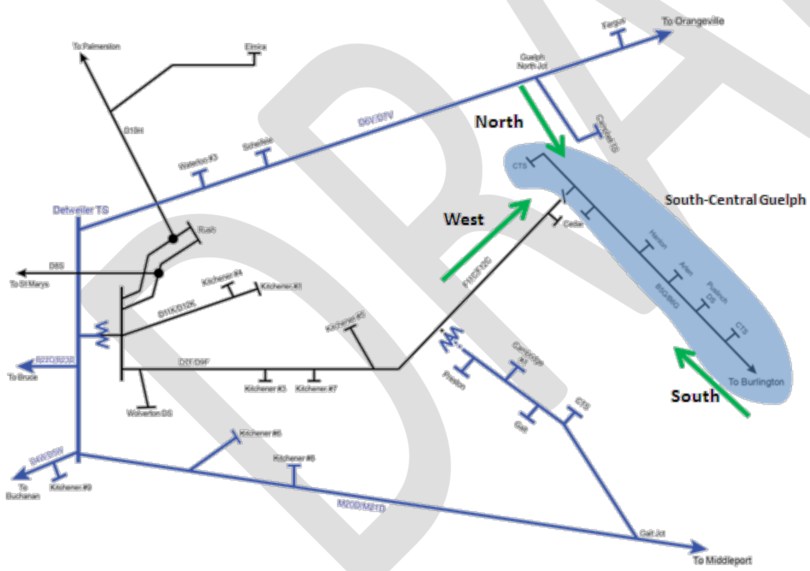
6.3.1 Transmission Options to Address Supply Capacity Needs

As noted in Table 5, three of the KWCG subsystems, namely the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems, already exceed or are expected to exceed their supply capacity. Transmission options for addressing these needs are discussed below.

Transmission Options for the South-Central Guelph Subsystem

The capacity needs of the South-Central Guelph subsystem can be addressed by reinforcing the transmission system from the West, South, or North as shown in Figure 7 (see Appendix E.1 for more details).

Figure 7: Transmission Reinforcement Options for South-Central Guelph



Reinforcing supply from the South (Burlington TS)

To improve the load meeting capability of the South-Central Guelph area, the existing 115 kV supply from Burlington TS could be reinforced. This could be accomplished by re-conductoring the existing B5G/B6G circuits (approximately 42 km in length) with a higher rated conductor (e.g. 1100 A), or by converting the existing B5G/B6G supply to 230 kV.

Given the age and design of the existing 115 kV transmission supply to South-Central Guelph, Hydro One has determined that it would not be feasible to reconductor the existing B5G/B6G circuits; instead, a new line would have to be constructed. Rebuilding the existing transmission line at either 115 kV or 230 kV would be complex, requiring bypass facilities to maintain supply to the area during construction. It would also be relatively expensive (over $200 million) given the significant distance between Burlington TS and Guelph and the number of stations that would potentially require conversion. Accordingly, this alternative was not considered further for meeting the capacity needs of South-Central Guelph.

Reinforcing supply from the West (Kitchener-Guelph Subsystem)

Similar to reinforcing supply to South-Central Guelph from the South, the existing 115 kV supply to the Kitchener-Guelph subsystem (the D7F/D9F and F11C/F12C circuits from Detweiler TS) could be reinforced through reconductoring or rebuilding. Due to the age and design of the existing F11C/F12C circuits, however, Hydro One has determined that it would not be feasible to reconductor this transmission line. Therefore, reinforcement from the west would have to be achieved through rebuilding the existing 115 kV transmission line between Detweiler TS and CGE Junction (near Cedar TS) to a higher rated 115 kV or 230 kV facility and installing switching facilities at Cedar TS. Similar to the southern option, rebuilding this line would be complex, would require bypass facilities to maintain supply during construction, and would be expensive (over $130 million) given the significant distance between Detweiler TS and CGE Junction (approximately 33 km) and the number of stations that would potentially require conversion. Accordingly, this alternative was not considered further for meeting the capacity needs of South-Central Guelph.

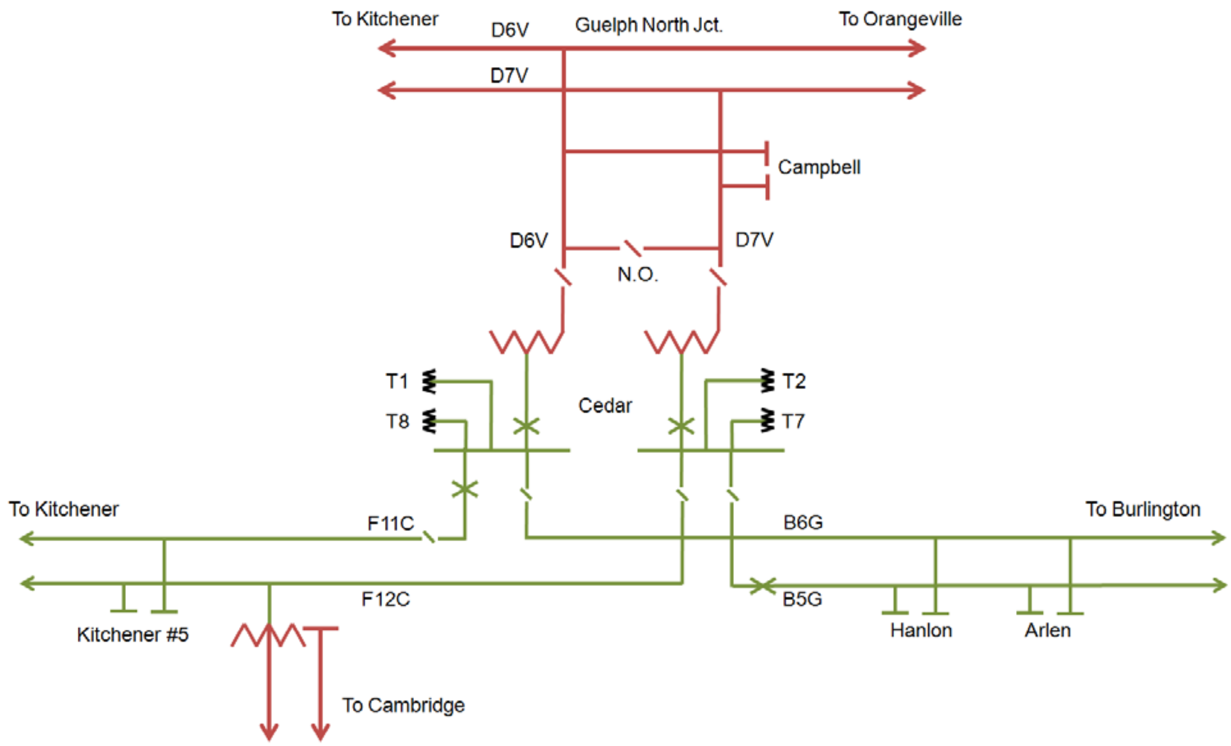
Reinforcing supply from the North (Waterloo-Guelph Subsystem)

Finally, additional transmission facilities could be constructed to reinforce the transmission supply to South-Central Guelph from the north. Upgrading the existing 115 kV transmission line between Campbell TS and CGE Junction to a double-circuit 230 kV transmission line, installing two new 230/115 kV autotransformers and four new 115 kV circuit breakers at Cedar TS, and transferring an existing directly connected customer in the area to the distribution system, would bring the northern 230 kV supply into the heart of Guelph.

At a cost of approximately $80 million, this alternative would provide a supply capacity increase sufficient to meet the needs of the South-Central Guelph area until beyond 2030, and could be completed by the end of 2015. While other options for reinforcing the transmission supply to South-Central Guelph from the north were considered (such as alternative switching arrangements, transferring a portion of the Cedar TS load to the 230 kV supply, and locating the two 230/115 kV autotransformers at a new site near Campbell TS), this option provides the greatest increase in supply capacity to South-Central Guelph, reduces the exposure of customers supplied by Cedar TS to supply outages, and provides better flexibility with respect to the end-of-life replacement of station equipment at both Cedar TS and Hanlon TS, which is anticipated to be required over the near- to medium-term. As noted below, it will also address the supply capacity needs of the Kitchener-Guelph subsystem. For these reasons, this is the preferred option for reinforcing the supply to South-Central Guelph (See Appendix F.6 for detailed analysis)..

The proposed system arrangement following the completion of recommended transmission reinforcement is shown in Figure 8.

Figure 8: Proposed Arrangement for Reinforcing the Transmission Supply to South-Central Guelph from the North



Transmission Options for the Kitchener-Guelph Subsystem

The preferred solution for South-Central Guelph will make Cedar TS a strong source of supply within the KWCG area. In addition to addressing the capacity needs of South-Central Guelph, this strong source of supply will also be sufficient to satisfy the capacity needs of the Kitchener-Guelph subsystem until beyond 2030. Other alternatives to meet the capacity needs of the Kitchener-Guelph area (e.g. rebuilding of the existing 115 kV supply) would require incremental transmission investments, and are not recommended.

Transmission Options for the Cambridge Subsystem

The installation of a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support, along with the preferred solution for South-Central Guelph, would result in improvements to the supply capacity of the Cambridge and Kitchener-Guelph areas. Following the installation of these facilities, sufficient capacity would exist on the Kitchener-Guelph 115 kV subsystem to accommodate the addition of a future Cambridge & North Dumfries Hydro station (Cambridge MTS #2). This would be sufficient to meet the capacity needs of the Cambridge area until the longer-term (2024), providing time to explore opportunities for further cost effective conservation and distributed generation, as well as transmission investments, such as voltage support and/or switching facilities (See Appendix F.6 for detailed analysis). As further explained below, the addition of this second autotransformer will also partly address the supply restoration needs in the area. This work would be coordinated with the reinforcement of South-Central Guelph and could be completed by the end of 2015 at a cost of approximately $15 million to $25 million.

6.3.2 Preferred Option to Address Supply Capacity Needs

In summary, the preferred transmission options for addressing the near- and medium-term supply capacity needs of the KWCG area are:

- installing two new 230/115 kV autotransformers, four 115 kV breakers, and advancing the relocation of the existing Hydro One Distribution Operating Centre at Cedar TS ($52 million);
- rebuilding approximately 5 km of existing 115 kV transmission line between Campbell TS and CGE junction in Guelph with a double-circuit 230 kV transmission line, and transferring the existing directly connected customer in the area to the distribution system ($27.5 million); and
- installing a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support ($15 million to $25 million).

Together, these improvements will at a total estimated cost of approximately $95 million to $105 million meet the capacity needs of the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems until 2024 or beyond.

6.3.3 Options to Reduce the Impact of Supply Interruptions

As noted in Table 5, two of the KWCG subsystems, namely the Waterloo-Guelph, and Kitchener and Cambridge subsystems, are unable to restore power to customers in the area within half an hour following a major outage as prescribed by the ORTAC service interruption criteria. Additionally, over the longer-term, demand in these two areas is expected to exceed the maximum 600 MW load interruption level prescribed by ORTAC.

These supply interruption needs can be partly addressed through the foregoing recommended capacity improvements, and the remaining supply interruption need can be satisfied through the following two transmission options 1) the implementation of load transfers following an outage, and/or 2) the installation of switching facilities, such as mid-span openers, motorized disconnect switches or circuit breakers. These potential options are evaluated below.

Options for the Waterloo-Guelph Subsystem

<u>Load Transfers</u>

One method of reducing supply interruptions to customers in the Waterloo-Guelph subsystem is to execute load transfers at the distribution level following a major transmission outage. KWCG area LDCs have identified little to no transfer capability of the loads in the area, and given the length of the D6V/D7V transmission line (about 77 km) and the amount of load served (over 400 MW), a number of load transfers, likely spanning significant distances (e.g. nearly 30 km between Orangeville TS and Fergus TS), would have to be implemented after each major transmission outage. It is the OPA's view that implementation of this option in order to comply with the ORTAC interruption criteria is not technically feasible. Accordingly, this alternative was not considered further as a means of reducing the impact of supply interruptions to customers in the Waterloo-Guelph subsystem.

<u>Mid-Span Openers</u>

Alternatively, installing mid-span openers at Guelph North Junction in the Township of Centre Wellington would facilitate the sectionalization of the D6V/D7V 230 kV circuits. Following a major transmission outage, the mid-span openers could be manually opened to isolate sections of the circuits and thus improve the restoration capability of the Waterloo-Guelph subsystem.

However, because the mid-span openers are manually actuated, restoration capability could only be improved within 4 to 8 hours, which is insufficient to meet the 30 minute ORTAC requirement for the Waterloo-Guelph subsystem. For this reason, mid-span openers were not considered further as a means of reducing the impact of supply interruptions to customers in the Waterloo-Guelph area.

Motorized Disconnect Switches

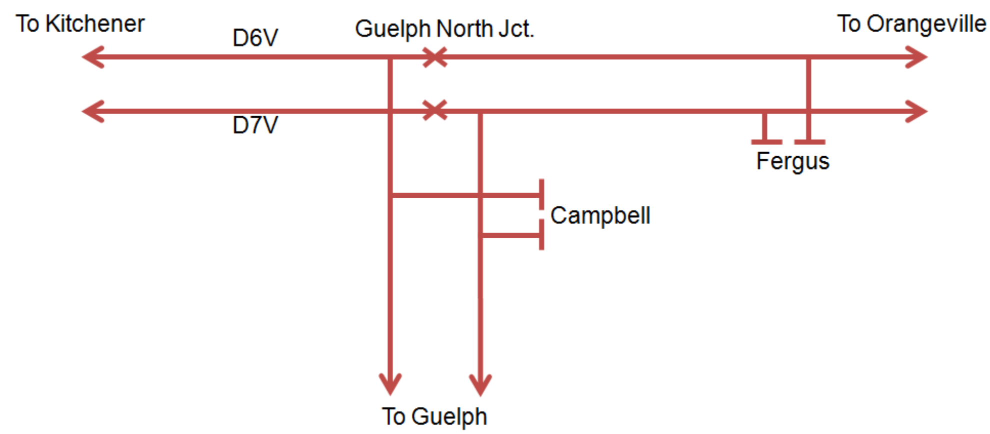
The installation of motorized disconnect switches at Guelph North Junction could also be used to facilitate the sectionalization of the D6V/D7V 230 kV circuits. These motorized switches could be operated remotely so that following a major transmission outage, load lost in excess of 250 MW in the Waterloo-Guelph area could be restored within 30 minutes. The estimated cost of this alternative is approximately $9 million to $12 million. While these facilities would address the near-term requirement for improved restoration capability, they would not address the longer-term need to prevent the interruption of demand in excess of 600 MW. To address this need, the installation of two 230 kV circuit breakers would be required in the longer-term at a cost of approximately $6 million to $15 million depending on the initial switching facilities installed. For the reasons noted below, this option was not preferred to installing new 230 kV circuit breakers at Guelph North Junction by 2015.

Circuit Breakers

Alternatively, two 230 kV circuit breakers could be installed at a new station (Inverhaugh SS) located at Guelph North Junction to facilitate sectionalization of the D6V/D7V circuits. The estimated cost of installing these breakers is approximately $16 million. This is roughly equivalent to the cost of installing motorized disconnect switches today and breakers in the longer-term. Compared to motorized disconnect switches, circuit breakers would reduce the exposure of customers in the area to supply outages by breaking the D6V/D7V circuits into three shorter sections (ranging from approximately 12 km to 35 km in length, compared to 77 km today). Circuit breakers also have a faster response time than motorized disconnect switches and would reduce the amount of time customers in the area would be without power following a major transmission outage. Finally, these facilities would address the future need to prevent the interruption of supply to customers in the area when demand on the D6V/D7V circuits exceeds

600 MW. For these reasons, the installation of two circuit breakers is the preferred option for reducing the impact of supply interruptions to customers in the Waterloo-Guelph subsystem. The proposed system arrangement after the installation of these breakers is shown in Figure 9.

Figure 9: Proposed Transmission System Configuration after the Installation of two 230 kV Circuit Breakers at Guelph North Junction



These facilities, along with the refurbishment of the existing transmission line between Campbell TS and CGE Junction, and the installation of two 230/115 kV autotransformers and four 115 kV in-line breakers at Cedar TS, are referred to as the Guelph Area Transmission Refurbishment project, or GATR project.

Kitchener and Cambridge Subsystem

The two preferred near-term projects for meeting the capacity needs of the KWCG discussed Section 6.3.2 would also increase the capability of the Kitchener and Cambridge subsystem to minimize the impact of major outages to customers in the area (See Appendix F.6 for detailed analysis). With these reinforcements, the transmission system will have the capability to restore approximately 100 MW of load in the Cambridge area within 30 minutes. Additionally, since the two preferred near-term projects enable the connection of the future Cambridge MTS #2 to the Kitchener-Guelph 115 kV system in 2018, customers supplied by the future Cambridge MTS #2 (up to 100 MW) will no longer be interrupted following the loss of the M20D/M21D circuits. This represents a significant improvement to the capability of the transmission system to minimize the impact of supply interruptions to customers, and is the preferred solution for contributing to meeting the restoration needs of the Kitchener and Cambridge area. This solution also defers the potential interruption of load in excess of 600 MW in the Kitchener and Cambridge area well into the longer-term.

6.3.4 Preferred Options to Reduce the Impact of Supply Interruptions

In summary, the preferred options to reduce the impact of supply interruptions to customers in the KWCG area are to install two 230 kV circuit breakers at a new station located at Guelph North Junction (at an approximate cost of $16 million) and to install a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support (contingent on the development of the preferred capacity improvements in South-Central Guelph). The estimated cost of a second autotransformer at Preston TS (approximately $15 million to $25 million) is included in the overall estimated costs (approximately $95 million to $105 million) for the recommended capacity improvements.

6.4 Summary of the Near-and Medium-Term Plan

Consistent with the regional planning process endorsed by the Ontario Energy Board (OEB) as part of its Renewed Regulatory Framework for Electricity, the preferred transmission reinforcements identified in Section 6.3.2 and Section 6.3.4 for addressing the near-term- and medium needs of the KWCG have already proceeded to the transmitter-led Regional Infrastructure Planning ("RIP") process for immediate implementation in advance of the IRRP process to meet needs in the near and medium term. At the time of this report, public consultations as well as environmental assessment related to the preferred transmission reinforcement have been completed and the preferred transmission reinforcements have already proceeded to a Section 92 Leave to Construct approval process.

7 Potential Options to Address Longer Term Needs in the KWCG Area

While the transmission facilities proposed by the Working Group in Section 6.3.2 and Section 6.3.4 along with planned conservation and existing distribution generation resources can meet the near- and medium-term needs of the KWCG area, some longer-term needs remains. Specifically, there are longer term needs to provide sufficient transmission capacity to connect a new transformer station in the Cambridge area (Cambridge MTS #3) towards the end of the study period (beyond 2024) and to investigate potential for further improvements to minimize the impact of major outages to customers in the Kitchener and Cambridge area (Table 5).

Table 3 Summary of the Longer Term Needs in the KWCG Area after the Contribution of Conservation and Distributed Generation Resources

Need Type	Subsystem	Need Description	Reference (After Conservation & Distributed Generation)
Capacity to Meet Demand	Cambridge 230 kV	Loading on M20D/M21D exceeds load meeting capability	~2024
	Kitchener & Guelph 115kV	Loading on D7/9F exceeds load meeting capability	Beyond 2030
	South-Central Guelph 115kV	Loading on B5/6G exceeds load meeting capability	~2029
Minimize the Impact of Interruptions	Kitchener & Cambridge 230 kV	To further improve the amount of load that can be restored on M20D/M21D under major outage conditions	Restoration of load > 250 MW: On-going
			Exceeds Max Allowable Load Loss of 600 MW: ~2030 [1]

Note: (1) Assumes future load growth in the Cambridge area over the longer term (i.e. Cambridge MTS #3) will be supplied from the Kitchener-Cambridge 230kV subsystem. If Cambridge MTS #3 is not connected on 230kV subsystem, the load on Kitchener-Cambridge 230kV subsystem will not exceed the allowable load loss of 600 MW over the longer term

Although the remaining needs in the KWCG area are not imminent and do not warrant immediate commitment of investments, the Working Group has developed a portfolio of high-level options in anticipation of longer-term needs in the KWCG area. Over the next few years, as the Working Group continues to monitor the electricity demand and the uptake of conservation and distributed generation resources in this region, further clarity on longer-term needs in the KWCG area will emerge. As appropriate, these longer-term options will be reviewed and revisited in subsequent regional planning study for the KWCG area. This section provides an overview of the longer-term integrated options developed for the KWCG area.

7.1 Potential Options to Address Supply Capacity Needs

7.1.1 Conservation Options

<u>Identifying opportunities for further cost effective conservation in the KWCG area</u>

The OPA will continue to monitor conservation results in the KWCG area and look for opportunities for further cost effective conservation to address supply capacity needs of the area over the long-term.

The OPA evaluates, monitors and verifies (EM&V) conservation programs on an annual basis, which strengthens confidence in the results and forecasts. In doing so, the OPA verifies actual demand reductions associated with program activities and rate structures to drive behavioural changes. It also tracks savings associated with regulated efficiencies from building codes and equipment standards. The performance of planned conservation resources in the near and medium-term will determine whether additional savings can be anticipated from planned resources in the longer-term as programs evolve to target new opportunities, prices motivate customers to invest in energy efficiency and codes and standards play an increasing role.

It may also be possible to do more conservation in the KWCG area above currently planned amounts in the long-term. For example, it may be possible to deliver targeted location-specific conservation programs or target marketing efforts for province-wide conservation programs in order to achieve additional savings above currently planned conservation activities.

The ability to do more conservation in the KWCG area above currently planned amounts depends on a number of factors, including system needs, achievable potential, capability to procure resources cost effectively and regulatory and policy developments.

Historically, conservation has been a resource focused on meeting province-wide capacity requirements and the costs have been recovered through the Global Adjustment Mechanism (GAM). Development work is needed to establish procurement and cost recovery mechanisms to support conservation (and other resources) driven by regional electricity needs to realize their full potential as a solution to meet regional reliability needs in the longer-term. Such work may be addressed as part of the regional planning framework that is being developed by the OEB through the RRFE.

There is also an urgent need to focus on the next program governance framework, which is set to expire in 2014. In particular, decisions needed with respect to funding mechanisms, governance options, program design and delivery types, procurement authority and various contractual and implementation requirements will play a role in determining the evolution of conservation activities in Ontario.

The uncertainty in the supply-demand outlook in the long-term is significant and the uncertainty increases further out into the planning horizon. Pacing procurement to align with system needs and to support the development of market capability will be key over the planning horizon. Ongoing planning processes will determine the right time to ramp up procurement and reassess needs.

The role of conservation to meet regional reliability in the long-term will depend on the particular circumstances of the area and will be considered along with other resources when assessing how best to address regional needs. Over the planning horizon, the OPA will continue to monitor conservation performance and take steps to develop conservation as an option to help meet long-term needs of the area.

7.1.2 Generation Options

Installing generation(s) (distributed, small or large scale) in the KWCG area

Additional generation, both small and large-scale, is a potential option to address the supply capacity needs of the KWCG area over the longer-term. Given the lead time of the generation options (typically 2-3 years depending on the technology type), and the timing of the longer-term needs (post 2024), a decision need not be made today on the specific recommended solution for the area. Instead, the generation options and their considerations are discussed generally below; the options will continue to evolve throughout the ongoing planning process for the area.

Cost Effectiveness

The cost effectiveness of generation is an important consideration in the evaluation of options and can hinge upon factors including: the generation technology, the co-existence of a system (i.e., provincial) need for additional supply resources, the timing, magnitude and nature of the needs in the local area and those at the system level, and the relative cost of other feasible alternatives – to name a few. For example, a generation alternative that can concurrently provide value to both the local area and the broader system is more favourable than one that cannot.

The current outlook anticipates a system level need for additional peaking resources to emerge in 2018, and a growing need for flexibility in the system to manage integration of intermittent renewable generation and the phase-out of coal generation. While peak capacity and flexibility will likely be needed, it is expected that the system will have sufficient generation output from the existing fleet of supply resources to meet energy needs at non-peak times. Additional resources should be considered in an integrated and coordinated manner, in the purview of both regional and system level needs so as to facilitate the best possible value proposition to the ratepayer.

In this context, gas-fired generation options including combined-cycle gas turbines (CCGT) and simple-cycle gas turbines (SCGT) may provide more value than intermittent renewables such as wind and solar resources and other gas-fired generation options including combined heat and power (CHP) as they provide peak capacity, are dispatchable and have the capability to tailor output to those times at which it is needed.

Feasibility

Small-scale generation sited close to the load centre is better suited to meeting smaller capacity needs, whereas large-scale generation centrally located is often better for serving larger capacity needs in the area due to economies of scale and lower project technical risk (from one project versus multiple). However, in both cases, the siting of the generation must be very specific – on specified circuits - such that the generation can contribute to the meeting all the capacity needs of the local area. Due to the specificity, additional transmission reinforcements may be required to accompany the generation and this can impact the economics of the generation options. In addition, siting may be a challenge if the generation is to be sited in densely populated and/or urban areas.

Environmental Considerations

While CCGT and SCGT gas-fired generation may be more suited to meeting the peak capacity needs of the local area and those of the system, it is recognized that their operation is associated with air emissions including oxides of nitrogen (NOx) and particulate matter (PM), as well as greenhouse gas emissions including carbon dioxide (CO2) and water-use. These emissions and water usage are not associated with the renewable generation alternatives. However, renewable generation employs significantly more land area than gas-fired generation alternatives – on both a MW of installed capacity and MW of effective capacity basis. These environmental considerations must be evaluated against the cost-effectiveness and feasibility considerations outlined above in determining the recommended solution.

7.1.3 Transmission and Distribution Options

<u>Upgrading the limiting section(s) of the Cambridge 230kV subsystem</u>

Over the longer term, a potential option to address the remaining supply capacity needs in the Cambridge area is to upgrade the limiting section(s) (Galt-Preston Jct and/or Preston Jct-Cambridge #1) of the Cambridge 230kV subsystem. This option would be sufficient to meet Cambridge's supply capacity need over the longer term.

Typically, the lead time required to upgrade an existing transmission line is about 4 years. The cost of the upgrade will depend on the nature of the upgrade required (e.g. uprating, re-conducting, or re-building) and the length of the transmission to be upgraded. While this option does not require a new transmission corridor, the existing transmission line from Galt Junction and Cambridge #1 Junction traverses urban and developed areas of Cambridge. As such, this option should be developed in coordination with key stakeholders and local communities in the Cambridge area. This option will be subject to regulatory approvals, such as Environment Assessment and Section 92 approval.

<u>Constructing a new transmission line to Preston TS</u>

An alternative option to address the longer term supply needs in the Cambridge area is to build a new transmission line to Preston TS. While the Working Group has not identified the exact routing at this time, there are potential transmission supply points to Preston TS from the west (Detweiler TS), the southwest (Kitchener-Cambridge 230kV System) or the East (near Puslinch).

Based on typical transmission development schedule, a new transmission line to Preston TS will likely take 6-7 years to come into service. Since a new transmission corridor will be required for this option, significant planning, coordination and engagement with key stakeholders and local communities will be required to secure a new transmission corridor that can potentially traverse through highly urbanized and developed regions within the KWCG area. Furthermore, this option is subject to regulatory approvals, such as Class Environment Assessment and Section 92 Leave to Construct.

While a new transmission line to Preston TS is a major infrastructure investment, which can cost in the in the order of hundreds of millions, this option brings a new supply into the KWCG area and provides a large incremental supply capacity to the region. As such, this option can be cost-effective option when there is a need for additional supply capacity across the entire region, such as in the case of the higher growth scenario, where there are supply capacity needs on the South-Central Guelph 115kV, Kitchener-Guelph 115kV and the Cambridge 230kV subsystem, as discussed in Section 7.3.

7.2 Potential Options to Reduce the Impact of Supply Interruptions

7.2.1 Conservation Options

As discussed in Section 6.1, while conservation can be an effective means of addressing capacity needs, conservation cannot aid in the restoration of power customers following a major transmission outage, and therefore cannot resolve the KWCG area's restoration needs.

7.2.2 Generation Options

Installing new generation(s) (distributed, small or large scale) in the KWCG area

The ability of generation (both large and small scale) to restore load can be limited, and can be a function of the following aspects:

- Safety protocols and other operating procedures of the distribution/transmission system;
- The ability of the generator to restart without an external power supply (i.e., "black-start capability");
- The facility's start-up time, time to synch to minimum loading and ramp rate;
- The existence of fast-acting isolating switching in the distribution/transmission system; and,
- The location of the generation facilities in relation to the restoration needs.

For these reasons, it can be difficult for generation alone, to restore loads and reduce the impact of supply interruptions to customers. It is, however, more likely for gas-fired generation to have the technical capability to restore loads than renewable generation – which can be limited by the availability of the fuel source. These additional generation capabilities would have to be specified during project procurement and factored into the cost, along with additional transmission reinforcements required to support the generation in restoring loads. In addition to the cost of the generation, feasibility and environmental considerations, as outlined in Section 7.1.2, will need to be considered. As noted earlier, given the lead time of the generation options (2-3 years), together with the timing of the longer-term needs (post 2024), a specific solution will not be recommended at this time. Instead, as part of the ongoing planning activities, the OPA will continue to monitor load growth and the needs in the KWCG area and further develop and adjust the alternatives so as to be adaptive to changing conditions.

7.2.3 Transmission and Distribution Options

Installing isolating devices on M20/21D

Over the longer term, a potential option to minimize the impact of major outages to customers in the Kitchener and Cambridge area is to install isolating devices, such as mid-span openers, motorized disconnect switches and breakers on M20/21D. The extent to which this option can minimize the impact of major outages to customers will not only depend on the type of device that is installed, as described in Section 6.3.3, it will also depend the location of these isolating devices as well as supply availability at Preston TS in the longer term. In the absence of a strong supply at Preston TS (e.g. a new source at Preston TS), the ability to restore load in Cambridge following a major outage on the Cambridge 230kV system is limited by the availability of back up supply from the 115kV Kitchener-Guelph system. As such, while installing isolating devices along the M20/21D can reduce customer's exposure to outages and can restore load in the Kitchener area in a timely manner, unless there is a strong supply at Preston TS over the longer term, the ability to restore load in the Cambridge area will continue to be limited by the availability of back up supply from the 115kV Kitchener-Guelph system.

Typically, the lead time required to install isolating devices is about 2 years. The cost of installing these devices will depend on wide range of factors, such as land and protection equipment requirements. Depending on the availability of space at existing transformer stations and the layout of future transformer stations along the M20/21D, additional land acquisition along the M20/21D corridor may be required for this option.

Improving load transfer capability on the distribution system

Another option to minimize the impact of major outages to customers in the Kitchener and Cambridge area is to improve the ability to use the distribution system to transfer load from Kitchener-Cambridge 230kV system to an adjacent transmission facilities following a major transmission outage on Kitchener-Cambridge 230kV system. While the LDCs have indicated that there is little to no transfer capability on Kitchener-Cambridge 230kV system at this time, there might more opportunities for load transfer between the 230kV stations on the Cambridge-Kitchener 230kV system to the neighbouring 115kV system when Cambridge #2 MTS comes in-service in the medium term. Furthermore, if an isolating device is installed on Kitchener-

Cambridge 230kV system over the longer term, once the fault on the Kitchener-Cambridge 230kV system has been isolated, there might be opportunity for load to be transferred from stations directly affected by the outages to unaffected stations or to stations where load has already been restored.

7.3 Impact of Higher and Lower Demand Scenario in the Longer-Term

In order to manage the uncertainty and potential risks over the longer term, the Working Group also looked at the impact of higher and lower demand scenarios after the near-and medium-term transmission facilities proposed by the Working Group in Section 6.3.2 and Section 6.3.4 come into service in 2015. While the near-and medium-term transmission facilities will be sufficient to meet the supply capacity needs in the KWCG area under the lower demand scenario, under the higher demand scenario, there may be a need for additional supply capacity for the South-Central Guelph 115 kV, Kitchener-Guelph 115 kV and the Cambridge 230kV subsystem as early as 2020. Under all demand scenarios, there is an on-going need to further improve the amount of load that can be restored on the Kitchener-Cambridge 230kV subsystem. Recognizing the potential impact of higher demand growth in the KWCG area, the Working Group will continue to monitor the demand growth in the area and as appropriate, the longer-term options discussed in Section 7.1 and Section 7.2 will be reviewed, updated and revisited in subsequent regional planning study for the KWCG area.

Table 6 summarizes the impact of the higher and lower demand scenarios in the longer-term.

Table 6: Impact of Higher and Lower Demand Scenario after GATR and the installation of a second 115/230kV autotransformer at Preston TS and associated switching and reactive support

Need Type	Subsystem	Need Description	Reference (After Conservation & Distributed Generation)	Lower Demand Scenario	Higher Demand Scenario
Capacity to Meet Demand	Cambridge 230 kV	Loading on M20D/M21D exceeds load meeting capability	~2024	Beyond 2030	~ 2020
	Kitchener & Guelph 115kV	Loading on D7/9F exceeds load meeting capability	Beyond 2030		
	South-Central Guelph 115kV	Loading on B5/6G exceeds load meeting capability	~2029		
Minimize the Impact of Interruptions	Kitchener & Cambridge 230 kV	To further improve the amount of load that can be restored on M20D/M21D under major outage conditions	Restoration of load > 250 MW: On-going	Restoration of load > 250 MW: On-going	Restoration of load > 250 MW: On-going
			Exceeds Max Allowable Load Loss of 600 MW: ~2030[1]		Exceeds Max Allowable Load Loss of 600 MW: ~2025[2]

Note: (1) Assumes future load growth in the Cambridge area (i.e. Cambridge MTS #3) will be supplied from the Kitchener-Cambridge 230kV subsystem.
(2) Under the higher demand scenario, even if Cambridge MTS # 3 is not supplied from the Kitchener-Cambridge 230kV subsystem, the load on Kitchener-Cambridge 230kV subsystem will exceed the maximum allowable load loss of 600 MW around 2025.

8 Recommendations for the KWCG Area

In order to address the near-medium term needs in the KWCG Area, the Working Group recommends an integrated package composed of 1) conservation, 2) distributed generation resources, and 3) transmission reinforcements in the KWCG area (specifically the GATR project, and the installation of a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support).

Together, conservation and distributed generation resources are expected to off-set more than 35% of the forecast load growth in the South-Central Guelph, Kitchener-Guelph and Cambridge subsystems between 2010 and 2023. These resources help to meet the existing reliability needs of the KWCG area, and also help to defer the need for longer-term investments in the region.

Transmission reinforcements are the final components of the integrated plan for the KWCG area. The total estimated cost of the transmission investments included in the integrated solution is approximately $110 million to $120 million: approximately $95 million for the GATR project, and approximately $15 million to $25 million for the installation of a second 230/115 kV autotransformer at Preston TS and associated switching and reactive support. Project completion is expected by the end of 2015, with development of the Preston TS autotransformer facilities being coordinated with completion of the GATR project.

At this time, while the Working Group does not recommend any near-term commitment of investment and facilities to addresses the longer term needs (beyond 2023), in anticipation for longer term growth in this area, the Working Group indicates the need to investigate opportunities for further cost effective conservation and distributed generation, as well as transmission investments. Monitoring of growth in electricity demand and the achievement of conservation and distributed generation in the KWCG area, will also be key components of on-going electricity planning in the region and the needs and the options in the longer term will be reviewed in subsequent KWCG regional planning study.

9 Implementation and Action Plan for KWCG Area

[Section 9 - Implementation and action plan to be developed with the Working Group]

9.1 Monitoring and Reporting

9.2 Conservation

9.3 Generation

9.4 Transmission and Distribution

9.5 Stakeholder Engagement

Appendix A

Study Terms of Reference

Terms of Reference

Kitchener-Waterloo-Cambridge-Guelph Area Electricity Supply Study

- The document was endorsed by the Working Group in October 2010 -

1. Introduction

A study was conducted in 2003 by Hydro One Networks, Hydro One Distribution, Kitchener-Wilmot Hydro Inc., Waterloo North Hydro Inc., Cambridge and North Dumfries Hydro Inc., and Guelph Hydro Electric Systems Inc. to assess the transmission system supplying the Kitchener-Waterloo-Cambridge-Guelph (KWCG) area for the 10 year period between 2002 and 2011. That study identified a number of thermal and voltage constraints in the area, and recommended remedial measures, including the installation of 230 kV capacitor banks at Detweiler TS, low voltage capacitor banks at Cedar TS, and a 230/115 kV autotransformer located at Preston TS in Cambridge. All these facilities are now in-service.

Since that study, there have been a number of system developments that impact on the supply to the KWCG area:

- The Integrated Power System Plan (IPSP) was prepared and filed with the Ontario Energy Board in 2007. One of the recommendations from the IPSP was the potential siting of a 450 MW gas-fired peaker plant located in the vicinity of Preston TS in Cambridge to serve both system and local needs. A number of transmission options as alternatives to the peaker plant were also identified. The review of the IPSP was subsequently placed on hold in September 2008.

- As part of the remedial plan for shutting down the Nanticoke coal-fired plant in southwestern Ontario and the return of the refurbished Bruce nuclear Units 1 and 2, Hydro One has sought and received approvals for the construction of the 2nd Bruce to Milton 500 kV double-circuit
- line for in-service by the end of 2012, and the installation of a 350 MVar Static Var Compensator (SVC) at Detweiler 230 kV TS and one at Nanticoke GS for in-service in May 2011. These facilities directly affect the loading and voltage performance of the bulk transmission system in the KWCG area.

On the non-facility side, the recent economic downturn, and the introduction of the Green Energy and Green Economy Act (GEGEA) also have major impact on the demand and supply situation in the area.

Additionally, due to 115 kV issues, there have recently been several outages from tie breakers forced to run in the open position at Burlington and therefore reducing capacity of the 115 kV system.

With all these changes and that the 2003 study considered the need only to 2011, the OPA, Hydro One and the affected LDCs in the area agreed that there is a need to develop a new regional plan for the KWCG area that incorporates the recent developments and system assumptions, updated demand forecasts, and the current planning criteria. In the IESO's December 2009 Ontario Reliability Outlook, a need for a solution to the existing transmission infrastructure was also identified.

This terms of reference outlines the objectives, scope and key assumptions that will be considered in this study.

2. Objectives

1. To assess the adequacy of the electricity supply to customers in the KWCG area over a 20 year timeframe for near-term requirements (within the next 5 years), mid-term optionality (within the next 5-10 years) and long-term direction (within the next 10-20 years).
2. For the needs identified, to determine integrated demand/supply options to address these needs.
3. To develop an implementation plan for the recommended solution options which may be published on the OPA website.

3. Scope

The scope of this Electricity Supply Study will include developing a regional plan to meet different timing and supply needs which involves a joint study between the OPA, LDCs and transmitter, as well as incorporating input from other agencies such as the IESO. The study will integrate load growth projections, bulk system needs, relevant community plans, FIT and other generation uptake, as well as local constraints to ensure that system adequacy needs arising from assessment of projected load growth are appropriately captured.

The scope of the study will include the established near-term need of South-Central Guelph. The preferred solution for South-Central Guelph reinforcement will be recommended as the first part of a staged approach to the KWCG Electricity Supply study.

The impact of the siting and connection of Cambridge #2 station and other stations required in the KWCG area will be assessed as part of this study.

<u>Study Period</u>

The scope of this study includes the near-term requirements, the mid-term optionality and long-term direction for the KWCG area over a 20 year period, commencing in the summer of 2010. In this context, near-term refers to the time period within the next 5 years; mid-term within the next 5-10 years; and long-term within the next 10-20 years.

<u>Electricity Supply System</u>

The study will consider infrastructure of the KWCG area which includes the four 230 kV circuits between Detweiler TS, Orangeville TS and Middleport TS, and the eight 115 kV circuits emanating from Detweiler TS and Burlington TS.

Figure A1-1 – Map of KWCG area

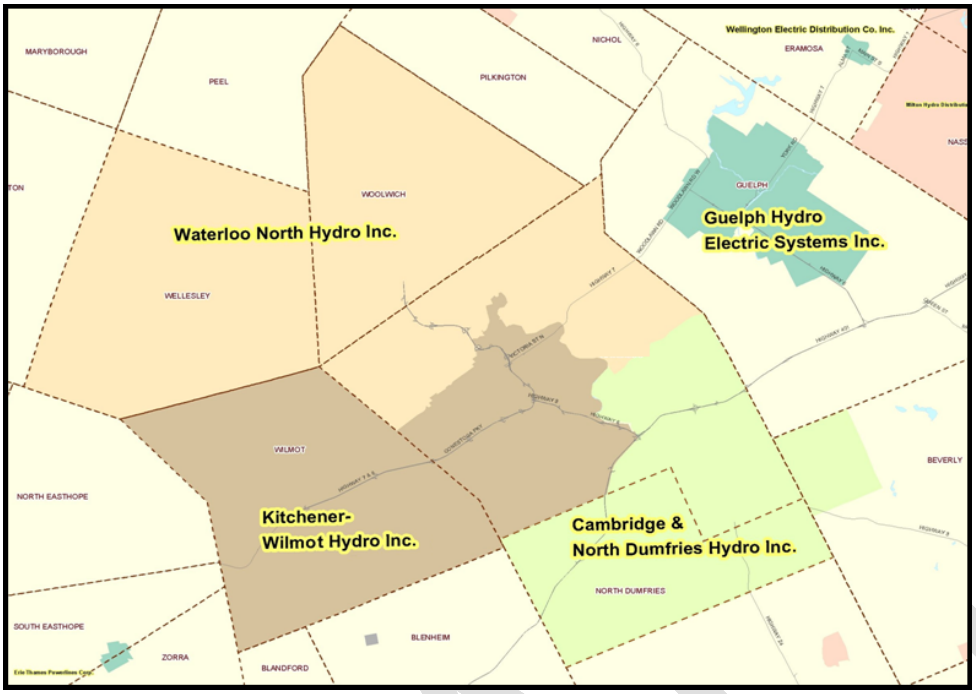
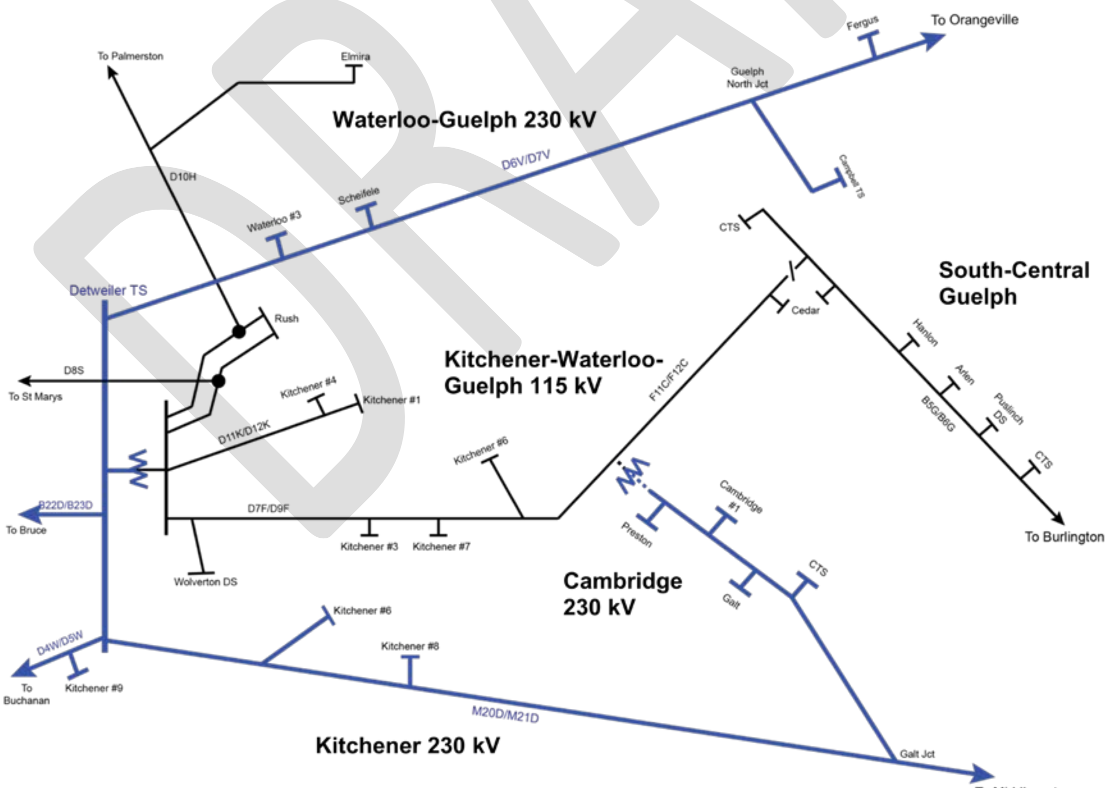


Figure A1-2 – KWCG Area Transmission System



Key Assumptions

The study will consider the following key assumptions.

- Demand Data
  - Historical load data from 2005 (or earlier) to 2010
  - Extreme summer peak data
  - LDC load forecast, considering higher and lower growth scenarios
  - Coincident KWCG area peak data including contracted load for Hydro One rural load and directly connected transmission customers
  - Coincidental peak data for local pockets as required
  - Relevance of Places to Grow Act, 2005

- Distributed Generation (DG)
  - Existing or committed renewable generation from FIT and non-FIT procurements
  - Future district energy plans, CHP developments

- Relevant community plans
  - e.g. Green Energy plans, Community long-term energy objective plans

- Conservation and Demand Response (DR) Programs
  - OPA provincial-wide conservation programs
  - LDC conservation programs

- Reliability Criteria (as per the Ontario Resource and Transmission Assessment Criteria)
  - Load supply capability
  - Load supply security/load restoration requirements as per Section 7.2

- Existing area network
  - Line ratings as per Hydro One database
  - Capability as per current IESO PSS/E base cases

- Bulk System assumptions to be applied to the existing area network that will be included in this study
  - Second Bruce x Milton 500 kV line in-service
  - F11/12C uprating
  - Committed Detweiler 230 kV 350 MVAr SVC
  - Distribution installed capacitor banks
  - Committed 230 kV and 115 kV capacitor banks in the area
  - Contracts awarded to FIT and MicroFIT applicants in the KWCG area as well as contracts in other southwest Ontario areas which are likely to impact the KWCG area

- Other assumptions
  - End-of-life/asset condition
  - Stranded assets

4. Study Team/Authority/ Funding

<u>Study Team</u>

The core study team will consist of planning and engineering representative(s) from the following organizations:

- Ontario Power Authority *(Team Lead)*
- Kitchener-Wilmot Hydro Inc.
- Waterloo North Hydro Inc.
- Cambridge and North Dumfries Hydro Inc.
- Guelph Hydro Electric Systems Inc.
- Hydro One Distribution
- Hydro One Networks Inc.
- IESO

Support from other groups as required.

Input from other entities such as large transmission connected industrial customers to be sought from Hydro One as required.

<u>Authority</u>

Each entity involved in the study will follow their own internal process on the approval of the proposed implementation plan resulting from this study.

<u>Funding</u>

For the duration of the study process, each participant is responsible for their own funding as necessary, for the study work required to be completed.

5. Activities and Primary Accountability

- Prepare draft Terms of Reference *(OPA)*
- Accept Terms of Reference *(All)*
- Establish demand data including:
  - Historical data *(OPA)*
  - Forecast data *(each LDC)*
- Establish existing, committed and potential DG including FIT and non-FIT uptake *(OPA and LDCs)*
- Provide information on Green Energy and other relevant community plans *(LDCs)*
- Establish conservation and DR programs to be included *(OPA and LDCs)*
- Complete system studies to identify supply need *(OPA, Hydro One, IESO)*
  - Obtain PSS/E base case from IESO
  - Including bulk system assumptions as identified in Key Assumptions
  - Applying reliability criteria as defined in the ORTAC
  - Establish need

- Develop options *(All)*
    - Conservation options *(OPA and LDCs)*
    - Local generation option *(OPA and LDCs)*
    - Transmission or distribution options including maximizing existing infrastructure capability *(OPA, Hydro One and LDC for DX option)*
    - Study impact of options on bulk system capability *(OPA, IESO)*

- Screen out and evaluate the most likely options *(OPA)*
    - Technical comparison, system studies etc
    - High-level economic, environmental and social acceptance assessment

- Recommendation of option/course of action *(OPA)*
    - Report of recommended option or course of action to reinforce South-Central Guelph and other near-term needs (Stage 1)
    - Report of recommended option or course of action for development work for the KWCG area over the longer-term (Stage 2)

- Development of implementation plan *(All)*

6. Deliverables

- Terms of Reference

- Statement of need

- Stage 1 Study Report for South-Central Guelph preferred solution

- Stage 2 Study Report for overall KWCG area

- Implementation Plan

7. Study Schedule

	Q1			Q2			Q3			Q4			Q1		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Accept Terms of Reference (All)															
Establish demand data															
(i) receive hourly data provided by the LDCs and establish 2010 summer historical peak															
(ii) receive reference case demand forecasts from LDCs															
(iii) receive high-growth demand forecasts from LDCs															
(iv) document forecasting methodologies by LDCs															
Establish existing, committed and potential DG including FIT and non-FIT uptake (OPA and LDCs)															
Provide information on Green Energy community plans etc (LDCs)															
Establish conservation and DR programs to be included (OPA and															
Base Case Development (OPA & IESO):															
(i) receive base case (from IESO)															
(ii) establish 'need' (OPA)															
(iii) complete system studies - Reference Case (OPA)															
Interim Options for near-term needs (OPA & H1):															
(i) develop interim options (OPA)															
(ii) confirm feasibility of interim options (H1)															
Screen out and evalulate most likely options for Longer-term															
(i) Gas option - complete studies (OPA/IESO)															
- develop plan for Gas (OPA)															
- confirm feasibility of Gas Plan (H1)															
(ii) TX option - screen out and evalulate most feasible TX options for longer-term solution (OPA/H1)															
High Growth Case Studies (OPA):															
(i) complete system studies (Needs, Gas plan, TX plans) (OPA)															
(ii) confirm interim options, gas plan options & TX options; revise options if needed (OPA)															
Documenting recommended option/course of action for Interim Options, Gas Option & TX Option (OPA & H1)															
Final Draft Report Documentation (All)															
Development of implementation plan (All)															
Stakeholders consultation (All)															
Final Report Documentation (All)															

Timelines developed by the working group

8. Communication and Stakeholdering

- The OPA will organize meetings for the study team when appropriate.
- Communication with other stakeholders external to the working group will be held when appropriate.

Appendix B

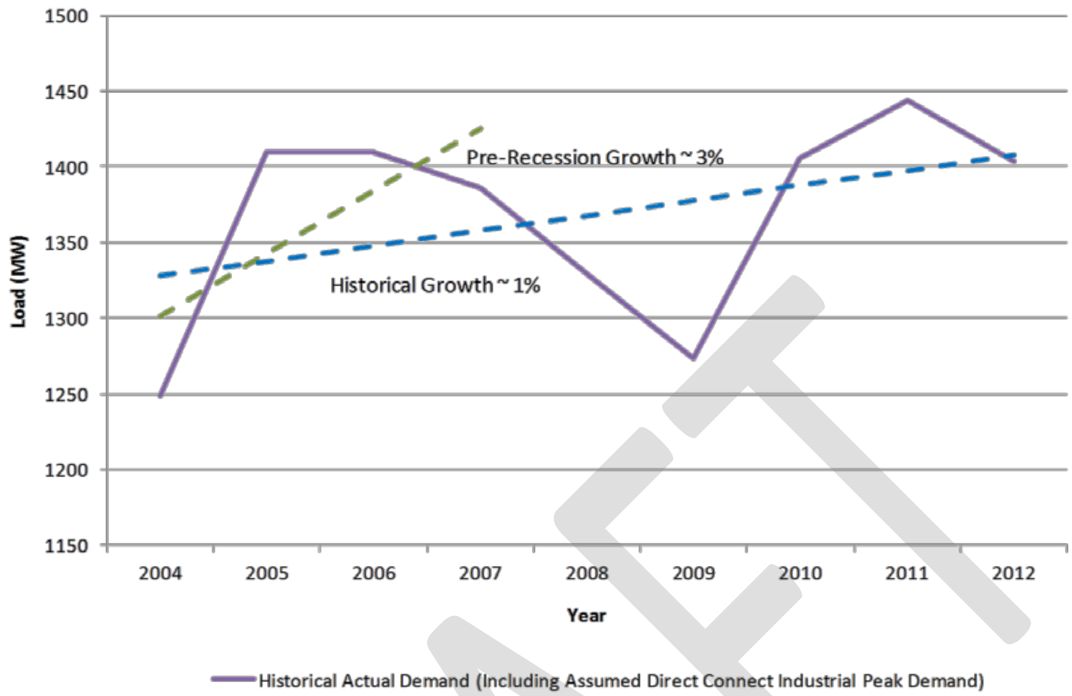
Electricity Demand in the KWCG Area

B.1 Historical Coincident Peak in the KWCG Area

From 2004 to 2005, KWCG area demand rose sharply; approaching the recession (which is defined as the years 2008 and 2009 for the purposes of this study), the growth slowed, and by 2009 the demand had fallen sharply back to almost 2004 levels. In 2010, demand began to recover and by 2011 demand had increased beyond prerecession levels. 2012 demand dropped slightly from 2011. All historical growth has been analyzed using statistical regression methods.

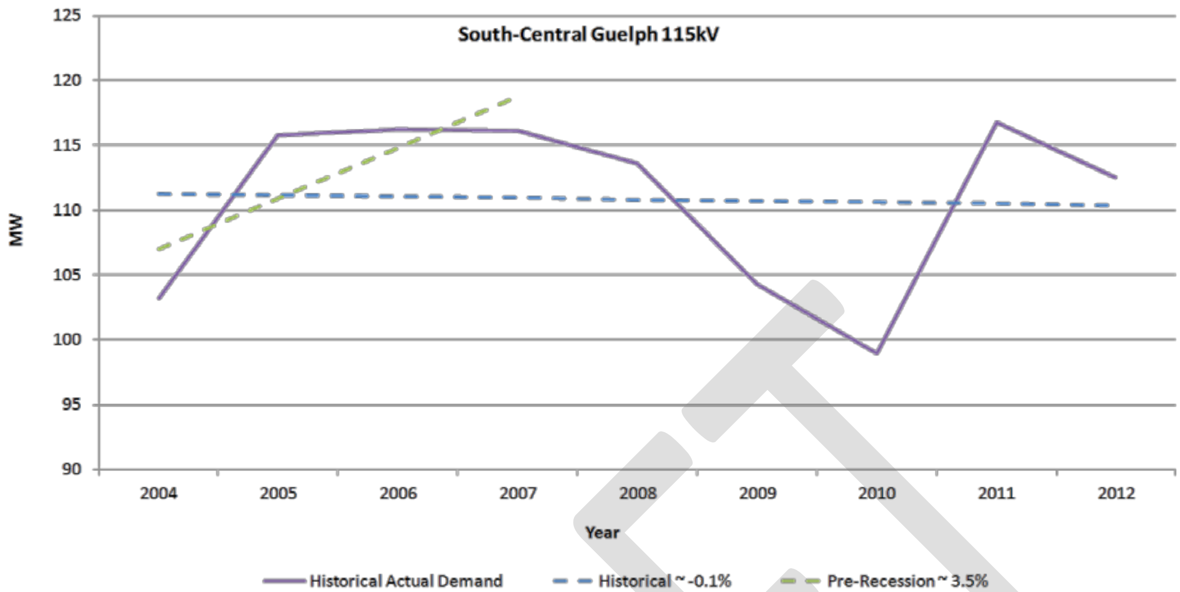
The demand for electricity in the KWCG area is influenced by a number of factors such as economic, household and population growth. These factors provides an indication of trend in electricity demand growth and do not necessarily have a one to one correlation with electricity consumption. Between 2004 and 2007, the average yearly electricity demand growth was over 3%. It is important to note that, in years unaffected by the recession, the trend for the area has been growth and recovery. Including the effects of the recession, the KWCG area average electricity growth rate between 2004 and 2012 was approximately 1%. GDP growth was nearly 2% per year throughout the 2004 to 2012 period in the Kitchener Region. During the same period, population growth averaged over 1% annually, with average annual household growth of nearly 2%. The direction of GDP, household and population growth is consistent with the trend in historical electricity demand in the area. Refer to Figure B1-1 for a summary of the growth of the KWCG area between 2004 and 2012.

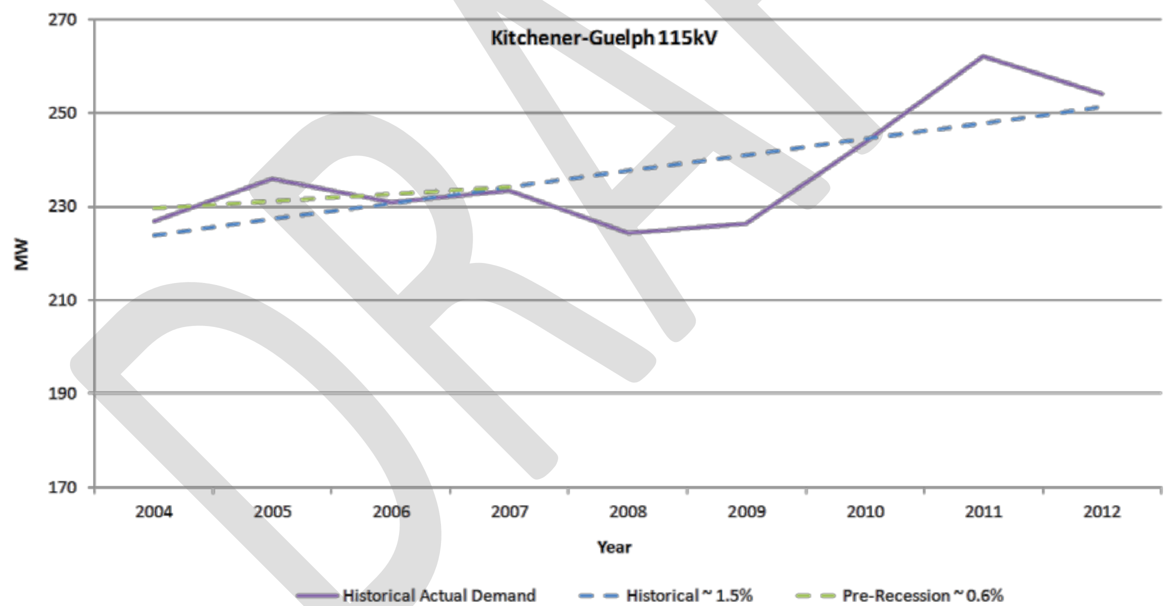
Figure B1-1: Historical Demand Trends

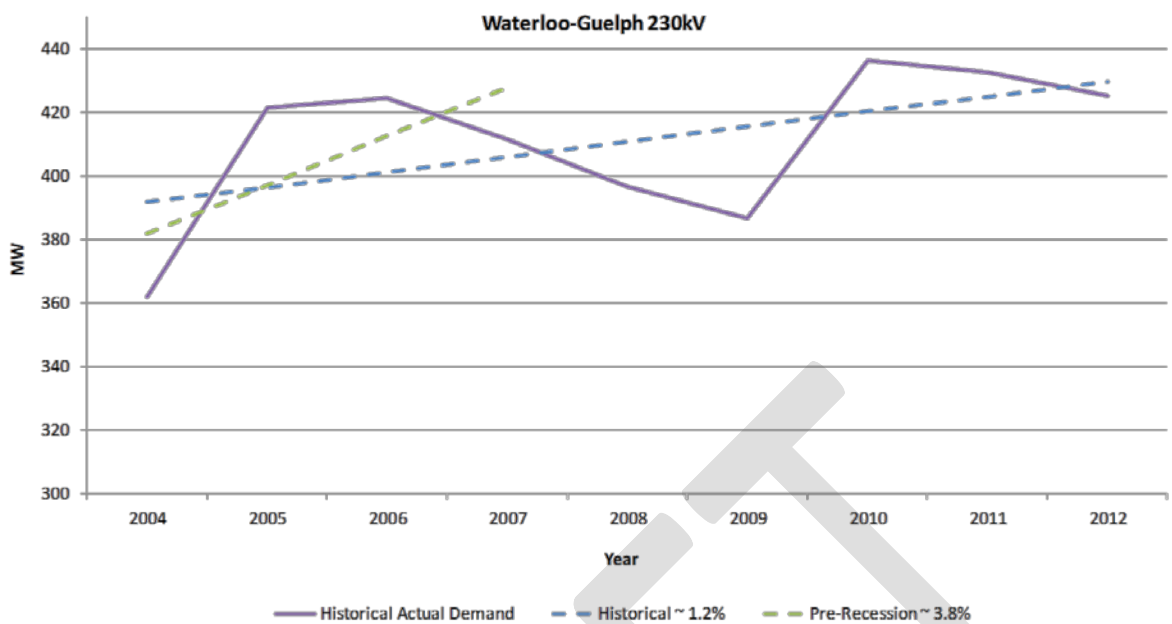


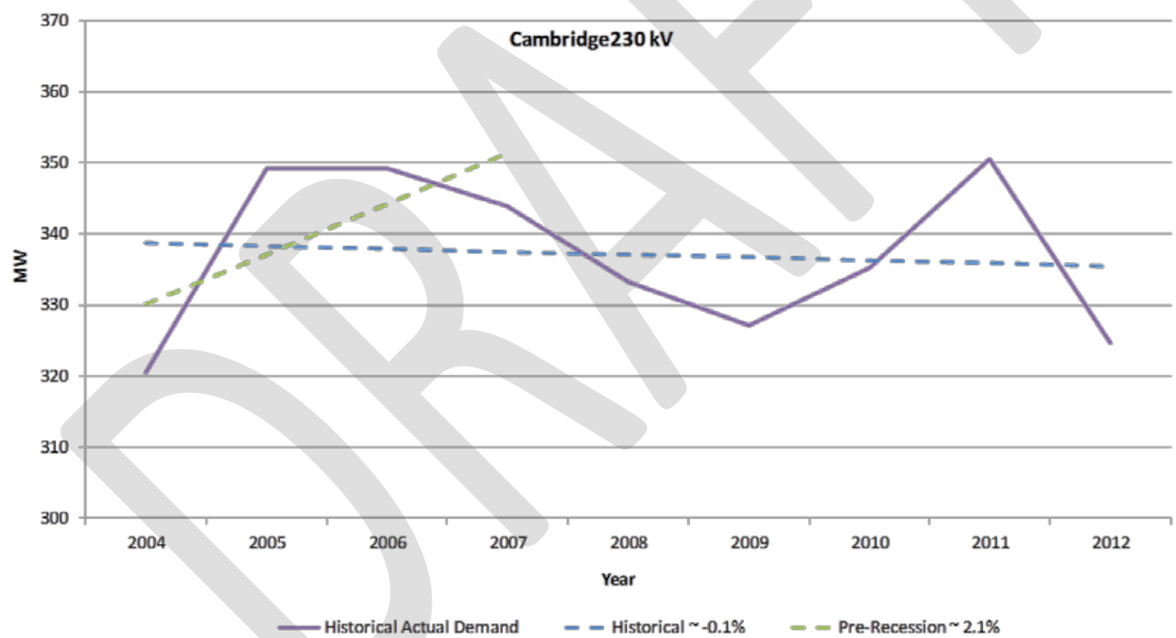
Each subsystem of the KWCG region has different historical growth rates and patterns. Some were influenced more heavily than others by the recession. Figure B1-2 illustrates the different patterns of historical growth by subsystem.

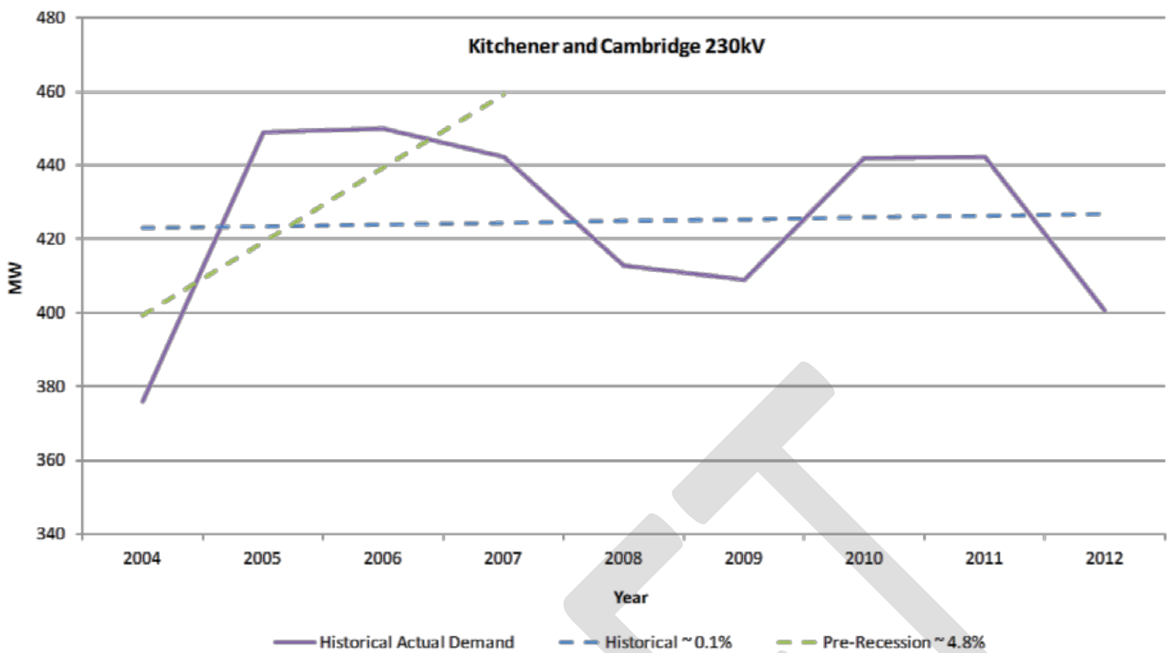
Figure B1-2: KWCG Subsystem Historical Growth






Waterloo-Guelph 230kV
MW
440
420
400
380
360
340
320
300
2004
2005
2006
2007
2008
2009
2010
2011
2012
Year
Historical Actual Demand
Historical ~ 1.2%
Pre-Recession ~ 3.8%


Cambridge230 kV
MW
370
360
350
340
330
320
310
300
2004
2005
2006
2007
2008
2009
2010
2011
2012
Year
Historical Actual Demand
Historical ~ -0.1%
Pre-Recession ~ 2.1%


Kitchener and Cambridge 230kV
480
460
440
420
400
380
360
340
MW
2004
2005
2006
2007
2008
2009
2010
2011
2012
Year
Historical Actual Demand
Historical ~0.1%
Pre-Recession ~4.8%

B.2 LDCs Gross Demand Forecast and Methodologies

As part of the KWCG regional planning study, the LDCs in the KWCG area, consisting of Cambridge and North Dumfries Hydro, Guelph Hydro Electric Systems Inc., Hydro One Distribution, Kitchener-Wilmot Hydro Inc. and Waterloo North Hydro Inc. provided the gross demand forecast for their service area over the a 20-year planning horizon (2010-2030) for median weather conditions. These forecasts were developed under coincident, median-weather assumptions, and adjusted to extreme weather conditions by the OPA. While the 2010 coincident summer peak for the KWCG area was initially used to establish the reference demand forecast and updates were made to the reference case after review of the 2012 information

Table B2-1 is the gross demand forecast for the KWCG area. The detailed documentation related to the methods and assumptions used to develop the gross demand forecast can found in this section.

Table B2-1: KWCG Reference LDC Gross Demand Forecast

	2010 Actual	2011 Actual	2012 Actual	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cambridge & North Dumfries Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Cambridge #1	78.2	70.4	74.8	62.8	74.7	86.3	97.9	109.9	109.9	111.7	112.4	113.0	113.5	114.0	114.3	114.7	114.9	115.2	115.5	115.6	115.9
Galt TS	135.4	137.6	133.9	170.2	173.8	176.7	179.5	182.2	184.5	186.7	188.4	190.1	191.4	192.7	193.8	194.7	195.5	196.2	197.1	197.6	198.2
Preston TS	81.8	102.5	75.8	119.4	121.8	123.6	125.4	127.1	128.6	130.0	131.0	132.1	133.0	133.8	134.4	135.0	135.6	136.0	136.5	136.8	137.3
Cambridge #2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.3	22.8	31.8	42.6	55.5	68.8	82.6	96.8	101.7	101.7	101.7	101.7	101.7
Cambridge #3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.5	24.5	34.7	50.4	66.5
Guelph Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Campbell TS	142.8	135.4	143.4	147.0	147.7	148.1	149.9	151.6	153.2	154.9	156.7	160.6	164.8	169.0	173.3	177.7	181.4	185.3	189.1	193.1	197.2
Cedar TS T1/T2	74.6	73.2	64.9	78.2	78.8	79.1	80.4	81.6	82.7	84.0	85.2	87.1	89.1	91.1	93.1	95.2	95.8	96.3	96.9	97.5	98.1
Cedar TS T7/T8	27.3		45.1	33.5	34.0	34.3	34.7	35.1	35.5	36.0	36.4	36.8	37.3	37.7	38.2	38.7	39.2	39.7	40.2	40.7	41.2
Hanlon TS	39.4	33.8	28.1	32.1	32.5	32.8	33.6	34.4	35.1	36.0	36.8	37.0	37.3	37.6	37.9	38.2	38.3	38.3	38.4	38.4	38.4
Arlen MTS	0.0	0.0	5.8	24.7	31.3	35.1	39.1	42.7	46.2	50.1	54.0	55.6	57.3	59.0	60.8	62.6	67.0	71.6	76.3	81.1	86.0
Kitchener-Wilmot Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Detweiler TS	29.5	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener #1	25.5	33.9	32.4	28.7	29.3	30.9	31.6	32.2	32.9	33.6	34.2	34.9	35.6	36.3	36.9	37.6	38.3	38.9	39.6	40.3	40.9
Kitchener #3	41.9	46.2	54.0	54.0	55.0	57.1	67.9	69.1	70.4	71.6	82.4	83.6	84.8	86.1	87.3	88.6	89.8	91.0	92.3	93.5	94.7
Kitchener #4	55.8	54.8	67.8	68.5	69.1	70.2	70.9	71.5	72.2	72.9	73.6	74.2	74.9	75.6	76.2	76.9	77.6	78.2	78.9	79.6	80.2
Kitchener #5	68.9	78.2	77.1	74.8	75.4	76.5	76.9	77.4	77.8	78.2	78.6	79.0	79.4	86.2	86.6	87.0	87.4	87.8	88.2	88.6	89.0
Kitchener #6	75.3	77.4	61.3	72.9	74.0	75.0	75.4	75.8	76.2	76.6	77.0	77.4	77.8	78.2	78.6	79.0	79.5	79.9	80.3	80.7	81.1
Kitchener #7	39.7	46.0	39.9	44.7	45.5	46.9	47.3	47.7	48.1	48.5	48.9	49.3	49.7	43.8	44.2	44.6	45.0	45.4	45.8	46.2	46.6
Kitchener #8	31.3	14.3	14.6	41.2	43.3	45.4	38.8	41.8	44.8	47.8	41.2	44.2	47.2	50.2	53.1	56.1	59.1	62.1	65.1	68.0	71.0
Kitchener #9	0.0	28.7	33.3	33.5	34.1	34.6	35.1	35.6	36.1	36.6	37.1	37.6	38.1	38.6	39.1	39.6	40.1	40.6	41.1	41.6	42.1
Waterloo North Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Elmira TS	32.4	32.9	32.5	32.9	33.9	34.9	29.5	30.3	31.2	32.5	33.8	35.1	36.6	38.0	39.5	41.1	42.8	28.4	29.6	30.8	32.0
Rush MTS	40.7	39.9	44.7	52.7	54.2	55.9	65.6	67.5	69.5	70.9	72.4	73.8	57.2	58.4	66.6	67.9	69.3	74.6	76.1	69.7	71.0
Scheifele TS	143.9	154.0	141.2	163.4	168.5	173.8	171.2	176.6	156.5	159.6	162.8	166.0	169.4	172.7	169.2	172.6	176.0	175.5	164.0	163.3	166.6
Waterloo #3	54.4	49.1	53.9	59.3	61.6	64.0	72.9	75.8	78.7	83.3	68.9	62.3	81.6	83.2	84.9	86.6	88.3	70.0	71.4	72.9	74.3
Snider TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.5	36.7	54.2	64.4	67.0	69.6	72.4	75.3	83.3	86.7	74.1	77.1	80.2
Bradley TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.1	67.8	81.2	82.8
Hydro One Distribution	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Fergus TS	95.4	94.2	86.7	110.0	111.0	112.0	113.0	114.0	114.9	116.0	117.0	118.0	119.0	120.0	121.0	122.1	123.5	125.0	126.5	128.1	129.6
Puslinch DS	25.2	25.0	26.5	33.2	33.9	34.6	35.4	36.1	36.8	37.5	38.3	39.0	39.7	40.5	41.2	41.9	43.2	44.1	44.9	45.8	46.8
Wolverton DS	18.9	18.6	18.3	20.5	20.7	20.9	21.2	21.4	21.6	21.9	22.1	22.3	22.5	22.8	23.0	23.3	23.6	23.9	24.2	24.5	24.8
OPA	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Total CTS	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0
Area Total (Gross)	1,405	1,393	1,403	1,605	1,651	1,696	1,740	1,784	1,834	1,883	1,922	1,963	2,007	2,051	2,095	2,141	2,192	2,240	2,283	2,332	2,381

Cambridge and North Dumfries Hydro

The load forecast supplied by Cambridge and North Dumfries Hydro (CNDH) covers the electrical loads in the City of Cambridge and the Township of North Dumfries excluding one large industrial load that is directly connected to the 230kV transmission system.

Cambridge and North Dumfries Hydro developed the reference level forecast growth rate by looking at historical actual system peak load data for each year between 1978 and 2012 then averaging the annual percentage change in summer peak load. The long term annual percentage change was approximately 3%. Therefore, a 3% annual growth rate was used for years 2012 through 2030. Cambridge and North Dumfries Hydro experienced negative peak summer load growth for four consecutive years prior to 2010 due to a combination of cooler summer weather and a poor economy. Since 1978, Cambridge and North Dumfries Hydro had never experienced more than two consecutive years of negative peak summer load growth. Growth reversed in 2012 with summer peak load falling 5% from 2011; this reflected a slow economy, especially on the industrial side as well as the impact of conservation and generation. CNDH noted that the KWCG and provincial peak occurred in July (for 2012) when one of their large industrial customers was on a week summer shutdown. If the large industrial customer had been in production, then CNDH's summer 2012 peak would have fallen only 2.3% from 2011. For the forecast starting point, CNDH assumed that the large industrial customer was in production during 2012 since it cannot be assumed that large industrial customer will always be out of production during the hottest, most humid weather conditions.

The timing for new stations was determined when the forecasted load (with a 6% adjustment for extreme weather) at existing stations exceeded the ten day summer LTR.

The methodology for determining when new stations are required under the high growth scenario remained the same. The timing moved up because of the higher growth rate.

Guelph Hydro Electric Systems Inc.

Introduction

Guelph Hydro Electric Systems Inc. (GHESI) owns and operates the electricity distribution system in its licensed service area in the City of Guelph and the Village of Rockwood serving approximately 50,000 Residential, Commercial and Industrial customers.

GHESI is supplied through the Hydro One transmission system at primary voltages of 115kV and 230kV. Electricity is then distributed through Hydro One owned transformer stations, Campbell TS, Cedar and Hanlon TS as well as a GHESI owned transformer station to be in-service in 2011.

Methodology used for developing the reference level load forecast

GHESI's methodology for developing the reference case load forecast consisted of a number of elements including historical loading trends, local knowledge of planned development and City of Guelph development planning information. Planning information from the City of Guelph was the starting point to formulate a maximum development forecast in order to set the parameters of the long range load forecast for our service territory given the 20 year study period. Using this information along with 20+years of historic peak loading information, local knowledge and information regarding transformer stations limitations within our service territory, the reference level load forecast was created for each delivery point location.

GHESI has experienced an on average system growth rate of approximately 1.95% over the past 20 years. The coincident peak of 284.1 MW in 2010 was used to establish the reference case load forecast for the study period until 2030; updates were made to the reference case after review of the 2012 load information. GHESI reached an all-time system peak of 293.2 MW in July 2011. For the reference case load forecast, a growth rate of approximate 2.4% is expected during the study period. In order to support the load growth for the reference case load forecast, upgrades at Campbell TS in 2015 as well as an upgrade to stations in the south end of Guelph are expected near 2025.

Methodology used for developing the high level load forecast

The same methodology was used to create the high level forecast. The forecasted growth rate for the high level forecast was calculated to be approximately 1.5 times that of the reference case. Under the high growth scenario, a load growth rate of 3.4% is expected during the study period.

Hydro One Distribution

Introduction and Background

Hydro One Distribution services the areas in the KWCG region that are not serviced by the LDCs via three step-down stations:

1. 230/44 kV Fergus TS supplied by 230 kV circuits D6V and D7V
2. 115/27.6 kV Puslinch DS supplied by 115 kV circuits B5G and B6G
3. 115/27.6 kV Wolverton DS supplied by 115 kV circuit D7F

Methodology for Reference Level Forecast

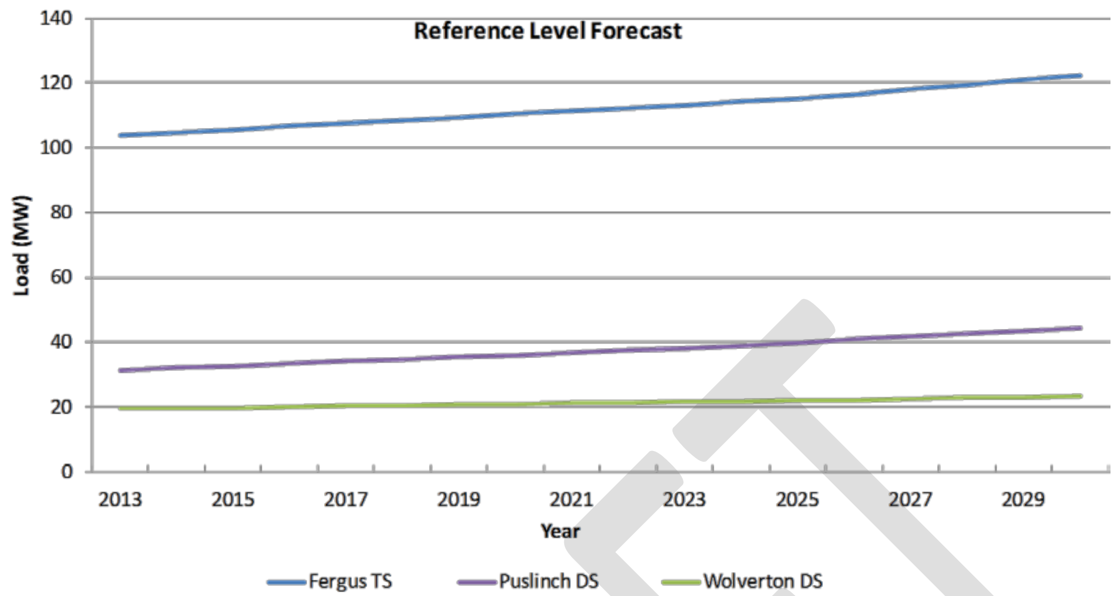
The reference level forecast is developed using macro-economic analysis, which takes into account the growth of demographic and economic factors. The forecast corresponds to the expected weather impact on peak load under average weather conditions, known as weather-normality. Furthermore, the forecast is unbiased such that there is an equal chance of the actual peak load being above or below the forecast. In addition, local knowledge, information regarding the loading in the area within the next two to three years, is utilized to make minor adjustments to the forecast.

Methodology for Adding New Stations

Hydro One Distribution conducts distribution area studies to examine the adequacy of the existing local supply network in the next ten to fifteen years and determine when new stations need to be built. These studies are performed on a needs basis, such as:

- Load approaching the planned capacity
- Issues identified by the field and customer
- Issues discovered during our 6-year cycle studies
- Additional supply required for large step load connections
- Poor asset condition

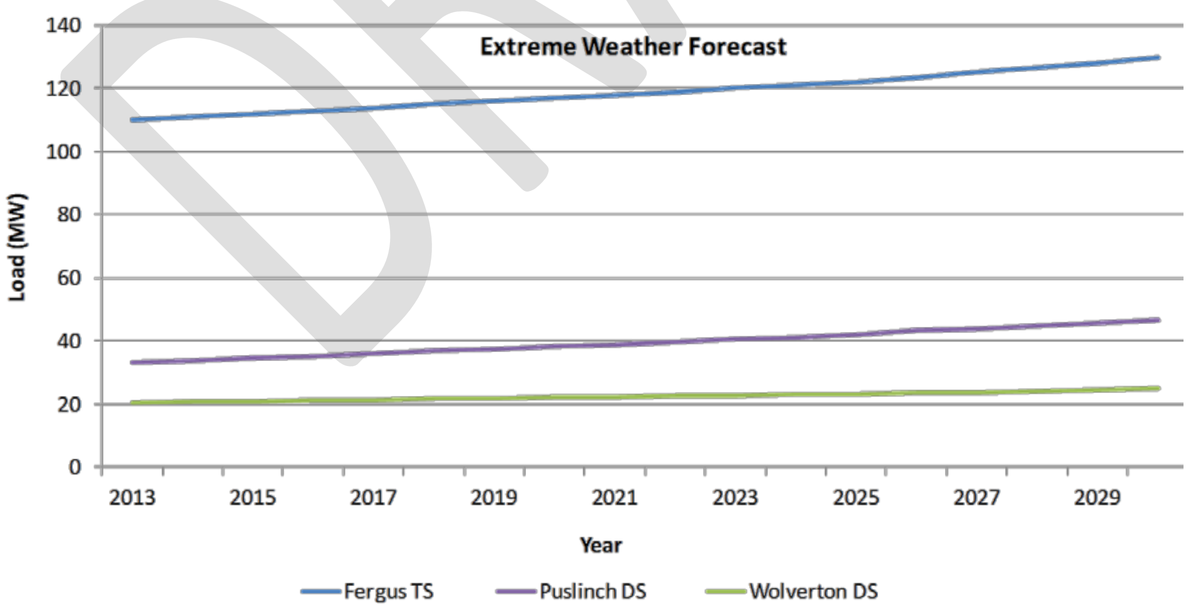
<u>Reference Level Forecast</u>



Methodology for Higher Level Forecast

The higher level forecast differs from the reference level by considering the expected weather impact on peak load under extreme weather conditions. As a result, an additional 6% is added to the reference level to obtain the higher level forecast.

<u>Higher Level Forecast</u>



Kitchener-Wilmot Hydro Inc.

Introduction

Kitchener-Wilmot Hydro owns and operates the electricity distribution system in its licensed service area in the City of Kitchener and the Township of Wilmot, serving approximately 85,800 Residential, General Service, Large Use, Street Light, Unmetered Scattered Load and Embedded Distributor Customers. Kitchener-Wilmot Hydro is supplied through the Hydro One transmission system at primary voltages of 115kV and 230kV. Electricity is then distributed through Kitchener-Wilmot Hydro's service area by 8 Municipal Transformer Stations and 7 Municipal Distribution Stations.

Methodology used for developing the reference level forecast growth rate

In developing the reference forecast, Kitchener-Wilmot Hydro uses Trend Analysis (trending) to extend past growth rates of electricity demand into the future. A linear-trend method that uses the historical data of demand growth to forecast future growth has been applied. The coincident peak data (July 7th, 2010 at hour 16) has been used as the base for load forecast. A long-term 6.86MW annual demand growth from 2011 to 2030 has been projected, with 60% annual load growth (4.12MW) attributable to the residential customers and 40% (2.74MW) attributable to the commercial and industrial customers. The annual demand growth has been allocated to each transformer station based on the municipal development plan, available vacant lands and other local knowledge.

This annual demand growth rate covers both load additions of the new customers and load maturation of the existing customers. The projected long-term annual demand growth is derived from the average load growth for the observed summer peaks from 1993 to 2006. The more recent data of 2007-2009 were biased and ignored due to loss of the largest load customer and the economic downturn after credit crisis.

In order to reflect some one-time new large load additions that are not covered by the historical trend (like the proposed regional LRT stations and a proposed solar panel fabrication facility), additional loads (6.5MW in total between 2011-2015) have been added to the 5 year short-term forecast on top of the long-term annual demand growth rate. That is, an average annual demand growth of 8.16MW is projected for the period 2011 to 2015.

Reference scenario load forecast (chart form)

See Table B2-1 below.

Based on the reference level forecast, expansion of Kitchener #5 TS from 83.3MVA to 100MVA is required in 2020. And expansion of Kitchener #8 TS from 50MVA to 100MVA is required in 2023.

Methodology used for developing the higher level forecast growth rate

The linear-trend method has also been applied to forecast the high growth scenario.

Different from the reference forecast, the projected long-term annual demand growth is derived from the average load growth for the observed summer peaks from 1997 to 2003, when relatively higher load growth was experienced.

A long-term 10.04MW annual demand growth from 2011 to 2030 has been projected, with 60% annual load growth (6.02MW) attributable to the residential customers and 40% (4.02MW) attributable to the commercial and industrial customers.

In order to reflect some one-time new large load additions that are not covered by the historical trend, higher additional loads (12.5MW in total between 2011- 2015) have been added to the 5 year short-term forecast on top of the long-term annual demand growth rate. That is, an average annual demand growth of 12.54MW is projected for the period 2011 to 2015.

High scenario forecast (chart form)

See Table B2-2 below.

Based on the high scenario forecast, expansion of Kitchener #8 TS from 50MVA to 100MVA is required in 2017, expansion of Kitchener #7 TS from 50MVA to 100MVA is required in 2022, and expansion of Kitchener #5 TS from 83.3MVA to 100MVA is required in 2025.

Table B2-2: Kitchener-Wilmot Hydro Inc. Reference Scenario Forecast

			2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Kitchener-Wilmot Hydro	**Station Limits MVA**	**Station Limits MW**	**Base MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**
Detweiler TS			**34.8**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener #9	**83.3**	**79.1**	**0.0**	30.5	31.0	31.6	32.1	32.7	33.1	33.6	34.1	34.5	35.0	35.5	35.9	36.4	36.9	37.3	37.8	38.3	38.7	39.2	39.7
Kitchener #1	**50.0**	**45.0**	**25.4**	26.0	26.5	27.1	27.6	29.2	29.8	30.4	31.0	31.7	32.3	32.9	33.6	34.2	34.8	35.5	36.1	36.7	37.4	38.0	38.6
Kitchener #3	**100.0**	**95.0**	**40.6**	43.0	50.0	51.0	51.9	53.9	64.0	65.2	66.4	67.5	77.7	78.9	80.0	81.2	82.4	83.5	84.7	85.9	87.0	88.2	89.4
Load Transfer					6.0				9.0				9.0										
Kitchener #4	**83.3**	**79.1**	**57.0**	57.5	64.1	64.6	65.2	66.2	66.9	67.5	68.1	68.8	69.4	70.0	70.7	71.3	71.9	72.5	73.2	73.8	74.4	75.1	75.7
Load Transfer					6.0																		
Kitchener #5	**83.3 (100 in 2020)**	**79.1 (95 in 2020)**	**69.0**	69.5	70.1	70.6	71.2	72.2	72.6	73.0	73.4	73.7	74.1	74.5	74.9	81.3	81.7	82.0	82.4	82.8	83.2	83.6	84.0
Load Transfer																6.0							
Kitchener #6*	**83.3**	**79.1**	**77.9**	78.9	67.9	68.8	69.8	70.7	71.1	71.5	71.9	72.3	72.7	73.0	73.4	73.8	74.2	74.6	75.0	75.3	75.7	76.1	76.5
Load Transfer					-12.0																		
Kitchener #7*	**50.0**	**47.5**	**39.9**	40.7	41.4	42.2	42.9	44.2	44.6	45.0	45.4	45.7	46.1	46.5	46.9	41.3	41.7	42.0	42.4	42.8	43.2	43.6	44.0
Load Transfer																-6.0							
Kitchener #8*	**50 (100 in 2023)**	**47.5 (95 in 2023)**	**31.4**	33.4	35.3	38.8	40.8	42.8	36.6	39.4	42.3	45.1	38.9	41.7	44.5	47.3	50.1	52.9	55.8	58.6	61.4	64.2	67.0
Load Transfer									-9.0				-9.0										

Notes:

1. Based Year: 2010 Summer peak (371MW, coincident peaks at 1600 on July 7th 2010 based on NV90 data - slightly lower than IESO billing data (372MW)
2. Wellesley DS (owned by Waterloo North) load included; DG (Waterloo LFG power plant) coincident peak considered (at 1600 on July 7th 2010).
3. Linear Load Growth Rate: 6.86MW/year based on historical data (1993-2006), data 2007-2009 ignored (loss of big customers, ecnomic downturn)
4. Total load growth be projected to each TS based on previous experience;
5. Large one-time load been added on top for 5-year short-term
6. 12 MW Load at Kitchener #6 TS to be transferred to #3 and #4 TS in 2012, 6 MW to #3TS, 6MW to #4 TS
7. 9 MW Load at Kitchener #8 TS to be transferred to #3 TS in 2016
8. #5 TS to be expanded to 100MVA in 2020.
9. 9 MW Load at Kitchener #8 TS to be transferred to #3 TS in 2020
10. #8 TS to be expanded to 100MVA in 2023
11. 6 MW Load at Kitchener #7 TS to be transferred to #5 TS in 2023
11. Load from Detweller TS DESN to be transferred to #9 TS by end of 2010, Detweiler TS DESN to be decommissioned after

B2-3: Kitchener-Wilmot Hydro Inc. High Scenario Forecast

			2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Kitchener-Wilmot Hydro	**Station Limits MVA**	**Station Limits MW**	**Base MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**
Detweiler TS			**34.8**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener #9	**83.3**	**79.1**	**0.0**	30.7	31.5	32.3	33.1	33.9	34.6	35.3	35.9	36.6	37.3	38.0	38.7	39.4	40.0	40.7	41.4	42.1	42.8	43.5	44.1
Kitchener #1	**50.0**	**45.0**	**25.4**	26.2	27.0	27.8	28.6	30.4	31.3	32.3	33.2	34.1	35.0	36.0	36.9	37.8	38.7	39.7	40.6	41.5	42.4	43.4	44.3
Kitchener #3	**100.0**	**95.0**	**40.6**	43.5	50.9	52.3	53.7	62.1	75.8	77.5	79.2	80.9	82.6	84.3	74.1	75.8	77.5	79.2	80.9	82.6	84.3	86.0	87.7
Load Transfer					6.0				12.0						-12.0								
Kitchener #4	**83.3**	**79.1**	**57.0**	57.8	64.6	65.4	66.2	67.5	68.4	69.4	70.3	71.2	72.1	73.0	74.0	74.9	75.8	76.7	77.7	78.6	76.5	77.4	78.4
Load Transfer					6.0																-3.0		
Kitchener #5	**83.3 (100 in 2025)**	**79.1 (95 in 2025)**	**69.0**	69.8	70.6	71.4	72.2	73.5	74.0	74.6	75.2	75.7	76.3	76.8	77.4	78.0	78.5	79.1	79.7	80.2	83.8	84.3	84.9
Load Transfer																					3.0		
Kitchener #6*	**83.3**	**79.1**	**77.9**	79.3	68.7	70.1	71.6	73.0	73.5	74.1	74.6	75.2	75.8	76.3	76.9	77.5	78.0	78.6	79.1	79.7	77.3	77.8	78.4
Load Transfer					-12.0																-3.0		
Kitchener #7*	**50 (100 in 2022)**	**47.5 (95 in 2022)**	**39.9**	41.0	42.1	43.2	44.3	46.0	46.5	47.1	47.6	48.2	48.8	49.3	61.9	62.4	63.0	63.6	64.1	64.7	71.3	71.8	72.4
Load Transfer															12.0						6.0		
Kitchener #8*	**50 (100 in 2017)**	**47.5 (95 in 2017)**	**31.4**	34.3	37.2	41.6	44.5	47.4	39.5	43.7	47.8	51.9	56.0	60.1	64.2	68.4	72.5	76.6	80.7	84.8	85.9	90.1	94.2
Load Transfer									-12.0												-3.0		

Notes: (High-Growth Scenario)

1. 1. Based Year: 2010 Summer peak (371MW, coincident peaks at 1600 on July 7th 2010 based on NV90 data - slightly lower than IESO billing data (372MW).
2. 2. Wellesley DS load included.
3. 3. Linear Load Growth Rate: 10.04MW/year based on high-growth historical data (1997-2003).
4. 4. Total load growth be projected to each TS based on local knowledge.
5. 5. Large one-time load been added on top for 5-year short-term.
6. 6. 12 MW Load at Kitchener #6 TS to be transferred to #3 and #4 TS in 2012, 6 MW to #3TS, 6MW to #4 TS.
7. 7. 12 MW Load at Kitchener #8 TS to be transferred to #3 TS in 2016.
8. 8. 12 MW Load at Kitchener #3 TS to be transferred to #7 TS in 2022.
9. 9. 6MW Load to be transferred to #7 TS in 2028, 3MW from #8TS, 3MW from #5TS.
10. 10. 6MW Load at Kitchener #4TS to be transferred to #5TS, and 3MW from #6 TS to #4 TS in 2028.
11. 11. #8 TS to be expanded to 100MVA in 2017.
12. 12. #7 TS to be expanded to 100MVA in 2022.
13. 13. #5 TS to be expanded to 100MVA in 2025.
14. 14. Load from Detweller TS DESN to be transferred to #9 TS by end of 2010, Detweiler TS DESN to be decommissioned after.

15. Dependable Capacity of existing DGs during summer peak has been included in the forecast.

Waterloo North Hydro Inc.

Waterloo North Hydro owns and operates the electricity distribution system in its licensed service area in the City of Waterloo and the Townships of Woolwich and Wellesley, serving approximately 52,000 customers. WNH's customer base is comprised of primarily residential and commercial/institutional loads. WNH's largest loads include universities, high-tech companies and financial institutions. A small component of the WNH load base comes from industrial/manufacturing sector.

Waterloo North Hydro is supplied through the Hydro One transmission system at primary voltages of 115kV and 230kV. Electricity is then distributed through Waterloo North Hydro's service area by 3 Municipal Transformer Stations and 16 Municipal Distribution Stations. The WNH distribution system is divided into the 13.8kV system servicing the core of the City of Waterloo and the 27.6kV system servicing the outskirts of the City of Waterloo as well as the township areas.

The system supply study is performed by WNH management, based in part on information gathered from regional and municipal authorities and development community stakeholders to evaluate the long-term (10+ years) supply needs of WNH and ensure system capacity to meet future growth. The study considers historical growth trends, forecasts and considers such factors as regional and provincial objectives and initiatives, regional/municipal development initiatives and plans and potential for development; the study also considers potential changes to development and growth rates, forecasts of electrical demand and future population, all of which provide a basis for determining transmission and transformation requirements at major supply facilities to ensure system capacity availability.

Methodology used for developing the reference case load forecast

In developing the load forecasts, Waterloo North Hydro gathers development projection data from the local municipalities and developers to determine areas and timing of planned development as well as land uses. This information is then converted to electrical demand quantities and analyzed against past trends. A forecast is developed for each transformer station that is consistent with load growth potential within the service area of that station and overall system growth.

WNH uses geometric growth trend method (trending) to extend past growth rates of electricity demand into the future. WNH has been trending the system peak data for the past 18 years and has analyzed this data with respect to typical rolling 3 year, 5 year, and 10 year growth rates. WNH service territory has consistently experienced rolling 10 year growth rates above 3%, sometimes reaching almost 4% (compared to the provincial average of 1%). Due to the fabric of the WNH customer base, the system peak for WNH is affected to a higher degree by weather and local development conditions and to a lesser degree by provincial or global factors. WNH's system peak has a tendency to rebound from recessions faster than in other Ontario jurisdictions. The historical load data from 1992 to 2010 includes 2 recessions as well as a mixture of hot and cool summers, and was therefore considered an appropriate blend to be used as a basis for future trending. The rolling geometric growth rate since 1992 is 3.0%. The latest 10 year geometric growth rate is 3.3%.

The coincident peak data (July 7th, 2010 at hour 16) has been used as the base for load forecast. A load forecast has been prepared such that by the end of the study period in 2030, the geometric growth rate is consistent with past trends and long term development potential. Year-to-year load projections were adjusted in terms of timing and location (station) based on knowledge with respect to local development conditions. This resulted in an overall geometric system growth rate of 3.3% up to year 2018 and 2.5% thereafter. This represents an addition of, on average, 10.3 MW of load per year over the study period. To support this level of load growth, multiple load transfers between stations plus 2 new Transformer Stations will be required, both connected to the D6V/D7V transmission lines: one in 2018 and one in 2027.

Methodology used for developing the high growth load forecast

The rolling geometric growth trend method has also been applied to forecast the high growth scenario. The projected long-term annual demand growth is derived from the 5 year rolling geometric growth rates observed a number of times in the past at over 4.5%. Such growth rates could very realistically be sustained if new types of loads developed such as high-tech data centres, Light Rail Transit supply stations, greater re-intensification of downtown core, or more aggressive development of new greenfield growth areas.

The high growth rate forecast was prepared using similar methods as well as timing and location adjustment factors as the reference case. This resulted in an overall geometric system growth rate of 4.25% up to year 2018 and 3.25% thereafter. This represents an addition of, on average, 14.9 MW of load per year over the study period. To support this level of load growth, multiple load transfers between stations plus 3 new Transformer Stations will be required, all connected to the D6V/D7V transmission lines: one in 2017, one in 2020, and one in 2029. In addition, upgrade of facilities from 13.8kV to 27.6kV will also be required: at Scheifele “A” transformer station in 2025 and at a major load customer in 2026.

B.3 OPA Input to Long Term Demand Forecast

The OPA produces long term (20 years) load forecast using an end-use model. Demand is forecasted by electrical zones, by sector, subsector and by end-use. Energy demand in an end use model is driven by growth drivers such as residential household, commercial floor space and industrial production. The growth drivers used are zonal specific and are subscribed from independent forecasting services. Demand is also affected by energy prices and efficiency of equipments and appliances. However, this end use approach is not usually used to produce local area demand forecast as it requires extensive and detailed input data. At a smaller footprint, demand forecasts should consider local conditions and development trends.

For the purpose of this regional planning, the LDC provided demand forecasts based on their knowledge of proposed developments and growth trends in their service area. Due to the varied methodology used by the LDC to produce their long term demand forecasts and also in the absence of growth driver information at the level of LDC's study area, the OPA can analyze demand forecasts directionally.

The economic forecast for Kitchener CMA, subscribed by the OPA from an independent economic forecast firm shows that there are factors contributing to demand growth in this region. The households in the Kicthener CMA are projected to grow at an annual rate of 1.2% between 2012 and 2031. Gross Domestic Product, one of the indications of economic growth is projected to grow by 2.1% for the same period. These are one of the many factors contributing to demand growth and they do not always have one-to-one correlation with electricity consumption. However, these factors do provide directional support to the demand forecast produced for the region.

B.4 Reference Net Demand Forecast and Methodology

For planning purposes, the net demand, which considers that some load will be conserved or met by distributed generation (DG), is used for determining the area's electricity needs. Both conservation and DG resources are discussed in Appendix C.1 and Appendix D.1, respectively.

After taking into consideration the combined impacts of conservation and distributed generation, a net-demand reference scenario was established. Table B4-1 below provides a detailed summary of the net demand reference forecast by station. This demand forecast was used in assessing the electricity needs of the KWCG area over the 20 year planning horizon.

Table B4-1: KWCG Reference Net Demand Scenario

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cambridge & North Dumfries Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Cambridge #1 Net Demand	78.2	70.4	74.8	58.9	69.3	79.8	90.5	101.5	100.6	101.7	101.7	101.7	101.7	101.7	101.7	101.7	101.7	101.7	101.7	101.7	101.6
Galt TS Net Demand	135.4	137.6	133.9	160.0	160.0	160.1	160.0	160.0	160.0	160.0	160.0	160.1	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
Preston TS Net Demand	81.8	102.5	75.8	113.3	113.3	113.3	113.3	113.3	113.3	113.3	113.3	113.3	113.3	113.3	113.3	113.3	113.3	113.3	113.3	113.3	113.3
Cambridge #2 Net Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.3	22.8	31.8	42.6	55.5	68.8	82.6	96.8	101.7	101.7	101.7	101.7	101.7
Cambridge #3 Net Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.5	24.5	34.7	50.4	66.5
Guelph Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Campbell TS Net Demand	142.8	135.4	143.4	134.8	131.8	129.5	128.7	127.7	127.0	126.7	126.8	129.3	132.0	135.1	138.4	141.9	144.8	148.0	151.1	154.6	158.1
Cedar TS T1/T2 Net Demand	74.6	73.2	64.9	74.6	73.8	73.0	73.3	73.4	73.7	74.1	74.7	76.0	77.4	79.0	80.6	82.3	82.6	82.8	83.1	83.5	83.8
Cedar TS T7/T8 Net Demand	27.3	50.9	45.1	30.2	29.7	29.2	28.9	28.6	28.4	28.3	28.2	28.2	28.3	28.5	28.6	28.8	29.1	29.4	29.7	30.1	30.5
Hanlon TS Net Demand	39.4	33.8	28.1	29.6	29.1	28.7	28.8	28.9	29.1	29.3	29.7	29.6	29.5	29.5	29.6	29.6	29.5	29.3	29.2	29.1	29.0
Guelph MTS#1 Net Demand	0.0	0.0	5.8	24.7	31.3	35.1	39.1	42.7	46.2	50.1	54.0	55.6	57.3	59.0	60.8	62.6	67.0	71.6	76.3	81.1	86.0
Kitchener-Wilmot Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Detweiler TS Net Demand	29.5	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener #1 Net Demand	25.5	33.9	32.4	27.3	27.4	28.7	29.0	29.3	29.6	30.0	30.4	30.9	31.4	31.9	32.4	32.9	33.5	34.1	34.6	35.2	35.8
Kitchener #3 Net Demand	41.9	46.2	54.0	50.8	50.6	51.7	61.5	61.9	62.3	62.8	73.0	73.7	74.5	75.3	76.2	77.1	78.1	79.1	80.0	81.1	82.1
Kitchener #4 Net Demand	55.8	54.8	67.8	64.3	63.3	63.1	62.6	62.0	61.6	61.4	61.3	61.2	61.3	61.4	61.6	61.8	62.2	62.5	62.8	63.3	63.6
Kitchener #5 Net Demand	68.9	78.2	77.1	70.3	69.0	68.7	67.8	66.8	66.1	65.5	65.0	64.6	64.3	70.5	70.4	70.3	70.4	70.4	70.4	70.6	70.7
Kitchener #6 Net Demand	75.3	77.4	61.3	68.8	68.1	67.9	67.1	66.3	65.7	65.2	64.9	64.6	64.4	64.2	64.2	64.2	64.2	64.3	64.4	64.6	64.7
Kitchener #7 Net Demand	39.7	46.0	39.9	42.3	42.1	42.8	42.5	42.3	42.1	42.0	42.0	42.1	42.1	35.9	36.0	36.2	36.4	36.7	36.9	37.2	37.4
Kitchener #8 Net Demand	31.3	14.3	14.6	39.4	40.9	42.5	35.4	37.9	40.4	43.0	36.1	38.8	41.5	44.3	47.0	49.8	52.7	55.5	58.4	61.3	64.1
Kitchener #9 Net Demand	0.0	28.7	33.3	26.6	26.5	26.6	26.6	26.5	26.6	26.7	26.8	27.0	27.2	27.5	27.8	28.1	28.4	28.8	29.1	29.5	29.9
Waterloo North Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Elmira TS Net Demand	32.4	32.9	32.5	30.8	31.0	28.6	22.6	22.9	23.3	24.1	25.0	26.0	27.1	28.3	29.6	31.0	32.5	18.0	18.9	20.0	21.1
Rush MTS Net Demand	40.7	39.9	44.7	50.3	50.9	51.8	60.8	62.1	63.5	64.4	65.3	66.4	49.5	50.3	58.2	59.3	60.5	65.7	67.0	60.4	61.6
Scheifele TS Net Demand	143.9	154.0	141.2	154.4	156.0	158.6	153.4	156.1	133.8	134.9	136.5	138.2	140.2	142.4	137.9	140.3	143.0	141.8	129.6	128.4	131.0
Waterloo #3 Net Demand	54.4	49.1	53.9	56.9	58.2	59.9	68.2	70.3	72.7	76.7	61.9	54.9	73.8	75.1	76.5	77.9	79.5	61.0	62.2	63.5	64.8
Snider TS Net Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.5	36.7	54.2	64.4	67.0	69.6	72.4	75.3	83.3	86.7	74.1	77.1	80.2
Bradley TS Net Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.1	67.8	81.2	82.8
Hydro One Distribution	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Fergus TS Net Demand	95.4	94.2	86.7	101.8	101.8	102.1	100.4	100.6	101.0	101.5	102.1	102.6	103.3	104.0	104.7	105.5	106.8	108.1	109.4	110.8	112.2
Puslinch DS Net Demand	25.2	25.0	26.5	31.7	31.8	32.1	32.3	32.6	33.0	33.4	33.8	34.3	34.8	35.4	35.9	36.5	37.7	38.4	39.2	40.0	40.8
Wolverton DS Net Demand	18.9	18.6	18.3	19.4	19.0	18.9	18.8	18.7	18.7	18.7	18.7	18.8	18.9	19.0	19.1	19.2	19.4	19.7	19.9	20.1	20.4
OPA	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Total CTS	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0.	47.0	47.0	47.0	47.0	47.0
Area Total (Net Conservation & DG)	1,405	1,444	1,403	1,508	1,522	1,540	1,559	1,580	1,610	1,640	1,665	1,692	1,723	1,757	1,792	1,829	1,875	1,916	1,952	1,997	2,041

B.5 Higher and Lower Demand Scenarios

In addition to the reference demand forecast, the Working Group has developed higher and lower demand scenarios to account for potential changes in demand growth. In the net reference demand forecast, the projected net demand growth rate between 2012 and 2030 is 2%. For the same period, net demand in the high demand scenario is projected to grow at 3% while net demand in the low demand scenario is projected to grow at 1%. These demand scenarios should be viewed as a range of potential outcomes that could be due to multiple variables. These variables include but are not limited to, the different rate and extent of industrial recovery, rate and extent of commercial activity growth, trends of customer energy use, uptake of distributed generation and success of conservation efforts. Given the economic make up of this region, changes in some of the variable mentions are heavily dependent of global forces as well as local trends.

Figure B5-1: Reference, Lower and Higher Demand Scenarios

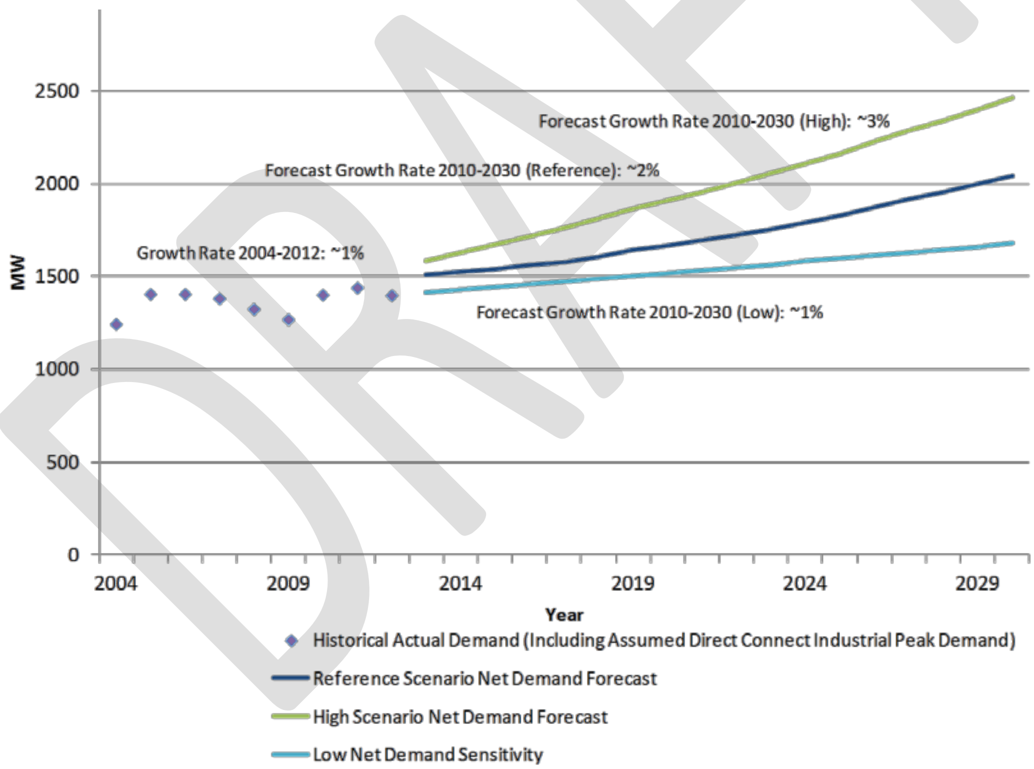


Figure 5-1 depicts historical and forecasted growth rates for the KWCG area. Historical growth averaged approximately 1% per year (2004-2012), including the effects of the recession. The net reference load forecast growth rate, which includes CDM and DG, is approximately 2%. The low and high forecast growth rates are 1% and 3%, respectively

Table B5-1: KWCG Higher Demand Scenario

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cambridge & North Dumfries Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Cambridge #1 Net Demand	78.2	70.4	74.8	60.8	72.0	83.1	94.2	105.7	105.3	106.7	107.0	107.4	107.6	107.8	108.0	108.2	108.3	108.5	108.6	108.7	108.8
Galt TS Net Demand	135.4	137.6	133.9	165.1	166.9	168.4	169.8	171.1	172.3	173.3	174.2	175.1	175.7	176.4	176.9	177.4	177.7	178.1	178.5	178.8	179.1
Preston TS Net Demand	81.8	102.5	75.8	116.3	117.5	118.4	119.4	120.2	120.9	121.6	122.1	122.7	123.2	123.5	123.8	124.2	124.4	124.6	124.9	125.1	125.3
Cambridge #2 Net Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.3	22.8	31.8	42.6	55.5	68.8	82.6	96.8	101.7	101.7	101.7	101.7	101.7
Cambridge #3 Net Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.5	24.5	34.7	50.4	66.5
Guelph Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Campbell TS Net Demand	142.8	135.4	143.4	140.9	140.3	139.8	141.5	143.1	144.8	146.9	149.3	154.6	160.3	166.3	172.6	179.1	179.8	180.4	181.1	181.9	182.6
Cedar TS T1/T2 Net Demand	74.6	73.2	64.9	77.2	78.2	78.8	79.6	80.2	81.0	81.9	82.8	83.9	85.0	86.1	87.4	88.7	88.7	88.7	88.7	88.7	88.7
Cedar TS T7/T8 Net Demand	27.3	50.9	45.1	32.3	32.4	32.4	32.6	32.9	33.1	33.5	33.9	34.3	34.8	35.4	35.9	36.5	36.5	36.5	36.4	36.4	36.4
Hanlon TS Net Demand	39.4	33.8	28.1	30.6	29.7	28.9	28.7	28.4	28.2	28.0	27.8	30.6	33.5	36.6	39.7	43.0	49.9	57.1	64.5	72.1	80.1
Guelph MTS#1 Net Demand	0.0	0.0	5.8	26.9	35.6	41.6	48.3	54.6	60.9	67.7	74.7	76.0	77.3	78.7	80.1	81.6	88.0	94.6	101.4	108.4	115.6
Kitchener-Wilmot Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Detweiler TS Net Demand	29.5	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener #1 Net Demand	25.5	33.9	32.4	28.8	29.4	31.1	31.9	32.7	33.5	34.4	35.2	36.1	37.0	37.9	38.8	39.7	40.6	41.6	42.5	43.4	44.4
Kitchener #3 Net Demand	41.9	46.2	54.0	53.8	54.7	63.1	77.2	78.5	80.0	81.4	82.9	84.5	73.3	74.9	76.5	78.2	79.9	81.6	83.2	85.0	86.7
Kitchener #4 Net Demand	55.8	54.8	67.8	67.2	67.3	68.0	68.4	68.8	69.2	69.7	70.3	70.9	71.6	72.3	73.0	73.8	74.6	75.4	73.1	73.9	74.8
Kitchener #5 Net Demand	68.9	78.2	77.1	73.4	73.3	74.0	73.9	73.8	73.8	73.9	74.1	74.3	74.5	74.8	75.2	75.5	75.9	76.3	79.9	80.4	80.8
Kitchener #6 Net Demand	75.3	77.4	61.3	72.3	72.9	73.8	73.8	73.8	73.9	74.0	74.2	74.5	74.8	75.1	75.5	75.9	76.3	76.7	74.0	74.5	74.9
Kitchener #7 Net Demand	39.7	46.0	39.9	44.6	45.3	46.7	46.9	47.2	47.5	47.9	48.3	48.7	61.8	62.3	62.7	63.2	63.7	64.2	71.1	71.6	72.1
Kitchener #8 Net Demand	31.3	14.3	14.6	43.2	46.0	48.8	40.2	44.3	48.4	52.6	56.8	61.0	65.3	69.5	73.8	78.1	82.3	86.6	87.7	92.1	96.4
Kitchener #9 Net Demand	0.0	28.7	33.3	30.8	31.3	31.9	32.4	32.8	33.3	33.8	34.4	35.0	35.6	36.2	36.8	37.4	38.1	38.7	39.4	40.0	40.7
Waterloo North Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Elmira TS Net Demand	32.4	32.9	32.5	33.7	34.7	34.4	35.6	28.9	29.9	31.1	32.3	33.6	26.9	28.1	29.3	30.5	31.9	25.3	26.4	27.6	28.9
Rush MTS Net Demand	40.7	39.9	44.7	54.1	63.9	66.1	68.5	70.9	69.6	71.5	64.5	66.4	68.3	70.3	68.4	70.4	54.5	60.2	68.1	70.2	64.3
Scheifele TS Net Demand	143.9	154.0	141.2	166.4	163.7	169.4	167.3	155.7	165.2	169.5	152.2	156.3	152.7	157.2	146.8	151.2	173.9	183.3	182.9	173.7	172.1
Waterloo #3 Net Demand	54.4	49.1	53.9	59.6	62.1	64.8	75.7	79.2	72.8	77.9	111.1	106.3	117.5	121.0	143.6	147.9	152.4	157.0	161.7	156.7	161.4
Snider TS Net Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.6	43.1	49.6	51.6	61.7	72.2	75.1	78.1	81.2	89.5	93.0	96.7	100.6	104.6
Bradley TS Net Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.0	40.8
Hydro One Distribution	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Fergus TS Net Demand	95.4	94.2	86.7	108.4	108.9	109.6	109.3	110.0	110.7	111.5	112.4	113.2	114.1	115.0	116.0	117.0	117.9	118.8	119.8	120.8	121.8
Puslinch DS Net Demand	25.2	25.0	26.5	31.1	31.5	31.9	32.4	32.9	33.4	33.9	34.5	35.0	35.6	36.3	36.9	37.5	38.2	38.9	39.6	40.3	41.0
Wolverton DS Net Demand	18.9	18.6	18.3	21.5	21.4	21.5	21.6	21.7	21.8	21.9	22.1	22.2	22.4	22.6	22.8	23.0	23.2	23.5	23.8	24.1	24.4
OPA	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Total CTS	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0
Area Total (Net Conservation & DG)	1,405	1,444	1,403	1,586	1,626	1,674	1,716	1,760	1,812	1,864	1,908	1,954	2,004	2,055	2,108	2,163	2,225	2,283	2,337	2,399	2,462

Table B5-2: KWCG Lower Demand Scenario

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cambridge & North Dumfries Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Cambridge #1 Net Demand	78.2	70.4	74.8	55.3	65.2	75.0	84.8	94.7	93.1	93.2	92.8	92.3	91.5	90.6	89.7	88.8	87.5	86.5	85.7	84.6	83.6
Galt TS Net Demand	135.4	137.6	133.9	150.4	150.5	150.3	149.9	149.4	148.1	146.7	146.0	145.2	143.9	142.6	141.2	139.7	137.6	136.0	134.8	133.2	131.6
Preston TS Net Demand	81.8	102.5	75.8	106.5	106.5	106.4	106.2	105.8	104.8	103.9	103.4	102.8	101.9	100.9	99.9	98.9	97.5	96.3	95.5	94.3	93.2
Cambridge #2 Net Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.4	20.9	29.0	38.6	50.0	61.3	72.8	84.5	87.5	86.4	85.7	84.6	83.6
Cambridge #3 Net Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.2	20.8	29.2	41.9	54.7
Guelph Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Campbell TS Net Demand	142.8	135.4	143.4	126.7	124.0	121.6	120.5	119.2	117.5	116.2	115.8	117.2	118.8	120.4	122.1	123.8	124.6	125.8	127.3	128.7	130.0
Cedar TS T1/T2 Net Demand	74.6	73.2	64.9	70.1	69.4	68.6	68.6	68.6	68.2	68.0	68.2	68.9	69.6	70.3	71.1	71.8	71.0	70.4	70.0	69.5	68.9
Cedar TS T7/T8 Net Demand	27.3	50.9	45.1	28.3	27.9	27.4	27.1	26.7	26.3	25.9	25.8	25.6	25.5	25.4	25.3	25.2	25.1	25.0	25.0	25.1	25.1
Hanlon TS Net Demand	39.4	33.8	28.1	27.8	27.4	26.9	27.0	27.0	26.9	26.9	27.1	26.9	26.6	26.3	26.1	25.8	25.4	24.9	24.6	24.2	23.8
Guelph MTS#1 Net Demand	0.0	0.0	5.8	23.2	29.4	33.0	36.6	39.9	42.8	46.0	49.3	50.5	51.6	52.6	53.6	54.6	57.7	60.9	64.3	67.5	70.8
Kitchener-Wilmot Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Detweiler TS Net Demand	29.5	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener #1 Net Demand	25.5	33.9	32.4	25.6	25.8	26.9	27.1	27.3	27.4	27.5	27.8	28.0	28.2	28.4	28.6	28.7	28.8	29.0	29.2	29.3	29.5
Kitchener #3 Net Demand	41.9	46.2	54.0	47.7	47.6	48.5	57.7	57.8	57.7	57.6	66.7	66.9	67.0	67.1	67.2	67.3	67.2	67.2	67.4	67.5	67.5
Kitchener #4 Net Demand	55.8	54.8	67.8	60.4	59.5	59.3	58.6	57.9	57.0	56.3	55.9	55.5	55.1	54.7	54.3	54.0	53.5	53.1	52.9	52.6	52.3
Kitchener #5 Net Demand	68.9	78.2	77.1	66.0	64.9	64.5	63.5	62.4	61.2	60.0	59.4	58.6	57.9	62.8	62.1	61.4	60.5	59.9	59.3	58.8	58.1
Kitchener #6 Net Demand	75.3	77.4	61.3	64.6	64.0	63.7	62.9	61.9	60.8	59.8	59.2	58.6	57.9	57.2	56.6	56.0	55.3	54.7	54.3	53.8	53.2
Kitchener #7 Net Demand	39.7	46.0	39.9	39.8	39.6	40.2	39.9	39.5	39.0	38.6	38.4	38.1	37.9	32.0	31.8	31.6	31.3	31.2	31.1	30.9	30.8
Kitchener #8 Net Demand	31.3	14.3	14.6	37.0	38.4	39.9	33.2	35.3	37.4	39.4	33.0	35.2	37.3	39.4	41.5	43.5	45.3	47.2	49.2	51.0	52.7
Kitchener #9 Net Demand	0.0	28.7	33.3	25.0	25.0	25.0	24.9	24.8	24.6	24.4	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.6	24.6
Waterloo North Hydro	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Elmira TS Net Demand	32.4	32.9	32.5	28.9	29.2	26.9	21.2	21.4	21.5	22.1	22.8	23.6	24.4	25.2	26.1	27.0	27.9	15.3	16.0	16.7	17.4
Rush MTS Net Demand	40.7	39.9	44.7	47.3	47.9	48.6	57.0	58.0	58.8	59.0	59.7	60.2	44.5	44.8	51.4	51.8	52.0	55.8	56.4	50.2	50.6
Scheifele TS Net Demand	143.9	154.0	141.2	145.1	146.7	148.9	143.7	145.8	123.8	123.8	124.6	125.4	126.1	126.9	121.6	122.5	123.1	120.6	109.2	106.8	107.8
Waterloo #3 Net Demand	54.4	49.1	53.9	53.4	54.8	56.3	63.9	65.7	67.3	70.4	56.5	49.8	66.4	66.9	67.5	68.0	68.4	51.9	52.4	52.9	53.3
Snider TS Net Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.2	33.7	49.5	58.4	60.2	62.1	63.9	65.8	71.7	73.7	62.5	64.2	65.9
Bradley TS Net Demand	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.7	57.2	67.6	68.1
Hydro One Distribution	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Fergus TS Net Demand	95.4	94.2	86.7	95.7	95.8	95.9	94.0	94.0	93.5	93.1	93.2	93.1	92.9	92.7	92.4	92.1	91.9	91.9	92.2	92.2	92.3
Puslinch DS Net Demand	25.2	25.0	26.5	29.8	29.9	30.1	30.3	30.5	30.5	30.6	30.9	31.1	31.3	31.5	31.7	31.9	32.4	32.7	33.0	33.3	33.6
Wolverton DS Net Demand	18.9	18.6	18.3	18.2	17.9	17.7	17.6	17.5	17.3	17.2	17.1	17.1	17.0	16.9	16.8	16.8	16.7	16.7	16.8	16.8	16.8
OPA	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
CTS Total	47.0	47.0	47.0	44.2	44.2	44.2	44.1	43.9	43.5	43.1	42.9	42.6	42.3	41.9	41.5	41.0	40.4	40.0	39.6	39.2	38.6
Area Total (Net Conservation & DG)	1,405	1,444	1,403	1417	1431	1446	1460	1475	1490	1504	1519	1535	1550	1565	1581	1597	1613	1629	1645	1662	1678

Appendix C

Conservation in the KWCG Area

Conservation plays a key role in extending the useful life of existing infrastructure, and maintaining reliable supply. Conservation reduces consumption of and/or demand for electricity through one of the following actions: energy efficiency, demand response, conservation behaviour, customer-based generation and other load reduction. Conservation is achieved through a mix of program-related activities, rate structures to drive behavioural changes, and through mandated efficiencies from building codes and equipment standards. These three approaches complement each other to maximize conservation results.

C.1 Conservation Forecast Methodology

The forecasted conservation savings for the KWCG region are derived from the provincial conservation forecast, which is in line with the conservation targets described in the Long-Term Energy Plan (LTEP) and prescribed in the Supply Mix Directive. The provincial savings are allocated to each LDC in the region based on the methodology used to allocate the 2014 LDC net annual peak demand savings targets. Those saving projections are further broken down to each station proportionally according to historical coincident peak. For the purpose of this study, peak demand savings incremental to 2010 are considered. The conservation forecast period is from 2011 to 2030.

In February 2011, the Minister of Energy issued a Supply Mix Directive establishing, among other things, conservation targets of 7,100 MW peak savings and 28 TWh energy savings by 2030. Interim targets for every five years were also established. The conservation targets will be achieved through a mix of program-related activities, customer behavioural changes due to rate structures and through mandated efficiencies from building codes and equipment standards. FIT and microFIT resources are not classified as conservation but generation. These provincial savings are allocated to LDCs and TSs in the region, as further described below.

Most stations in the KWCG region connect to the LDCs' distribution systems, while a few connect to direct customers. These two types of stations are treated separately when forecasting conservation savings; stations connecting LDCs use a top down conservation allocation methodology, while stations connecting direct customers use first hand program participation activities to allocate conservation. Both allocation methodologies are described in detail below.

Conservation Allocation Methodology for Stations Connecting LDCs

The distribution portion of provincial conservation forecast is determined for each of the conservation categories, programs, rate structures and regulation. Energy efficiency program savings include 2011-2014 OPA Contracted Province-Wide CDM Programs and 2015-2030 distribution connected resource acquisition forecasts. OPA Contracted Province-Wide demand response program savings include peaksaver, other direct load control, and the distribution component of DR1, DR2, and DR3. Time of use savings represent forecast savings anticipated to arise through time-of-use pricing, this analysis assumes the current 2:1 peak to off peak ratio.

In developing the provincial level conservation saving forecast, the OPA estimates savings from conservation categories at customer level. Transmission and distribution losses are then factored in to account for the conservation savings at generator level. For the purpose of this study, the distribution losses, based on the provincial average of 4.2% distribution loss factor, are included in the conservation savings of TSs serving LDC customers.

The provincial distribution level conservation savings are then allocated to the LDCs in the region. The allocation factors are derived from 2014 LDC conservation and demand management (CDM) targets set by the OEB. On March 31, 2010, the Minister of Energy and Infrastructure issued a directive to the OEB, instructing it to establish mandatory CDM targets for LDCs to achieve reductions in electricity consumption and reductions in peak provincial electricity demand over a four year period beginning January 1, 2011. The directive specified that the total of the CDM target established for all LDCs be equal to 1330 MW of provincial peak electricity demand and 6000 GWh of electricity consumption over the four-year period. On November 12, 2010, Ontario Energy Board issued *EB-2010-0215* and *EB-2010-0216* setting two CDM targets for each LDC: a 2014 net annual peak demand savings target and a 2011-2014 net cumulative energy savings target. The table below shows the targets of the LDCs in the study region as well as the calculated “Allocation Factor”.

Table C1-1: KWCG LDC Allocation Factors

Local Distribution Company	2014 Peak Demand Savings Target (MW)	Allocation Factor (%)
Cambridge and North Dumfries Hydro Inc.	17.68	1.3%
Guelph Hydro Electric Systems Inc.	16.71	1.3%
Hydro One Inc.	213.66	16.1%
Kitchener-Wilmot Hydro Inc.	21.56	1.6%
Waterloo North Hydro Inc.	15.79	1.2%

The allocation factor of an LDC is the percentage of its target over the total targets of all LDCs (1,330MW). The allocation factors are calculated from 2014 peak demand targets and assumed to be constant over the planning horizon. The annual provincial demand savings are multiplied by these allocation factors to determine the share of the projected conservation savings allocated to each LDC in the KWCG region.

Finally, the annual conservation projection for each LDC is further broken down to the station level. This is done based on the historical contribution of each station to the LDC's total coincident peak demand (the period between 2006 and 2008 was the most recent hourly demand data by station available when the analysis was performed). For example, GALT-LT.LFJ is one of the four stations serving Cambridge and North Dumfries Hydro Inc. In 2008, its coincident peak was 133 MW, representing 46% of Cambridge and North Dumfries Hydro's coincident peak. Applying the same approach, this station's peak represents 53% of the LDC's peak in 2007 and 51% in 2006. The station's load share for purposes of this assessment is the average percentage of these three years; in this case, 50%. Similar to the LDC allocation factor, a station's load share is assumed to be constant over the planning horizon. Using these load shares, an LDC's conservation forecast is broken down to all stations it connects to. For LDCs like Cambridge and North Dumfries Hydro, all their stations are in the study region and therefore all of their conservation projections are considered in the study. For LDCs like Hydro One, only a subset of their stations are located in the region, while the rest of their stations are outside the boundary. Therefore, only the conservation savings of the stations in the region are included in the study. Following this approach, conservation forecasts for all stations in the study region are determined for the next twenty years.

Conservation Allocation Methodology for Stations Connecting to Direct Customers

Besides LDCs, there are a couple of direct customers who are IESO market participants. Their facilities connect to the transmission network directly. The direct customers usually consume a larger amount of electricity and the consumption pattern is different from distribution level customers. As a result, the method used to allocate LDC conservation to stations is not applicable for them. The conservation projection of direct customers is determined by their program participation activities on a case by case basis.

The table below is a summary of conservation savings in MW at system coincident peak hour by station.

Table C1-2: KWCG Conservation Forecast by Station

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cambridge #1	1.0	2.1	3.3	4.6	5.6	6.6	7.6	8.5	9.2	9.9	10.5	11.0	11.4	11.8	12.2	12.4	12.7	13.0	13.2	13.4
GALT TS	2.7	5.9	9.3	12.9	15.7	18.4	21.2	23.6	25.7	27.4	29.0	30.5	31.7	32.7	33.7	34.5	35.3	36.0	36.5	37.2
PRESTON TS	1.7	3.7	5.9	8.2	9.9	11.7	13.5	15.0	16.3	17.4	18.4	19.4	20.1	20.8	21.4	21.9	22.4	22.9	23.2	23.6
WOLVERTON DS	0.3	0.6	1.0	1.4	1.7	2.0	2.3	2.6	2.8	3.0	3.2	3.4	3.5	3.6	3.7	3.8	3.9	4.0	4.0	4.1
CAMPBELL TS	2.6	5.6	8.9	12.3	14.9	17.6	20.2	22.5	24.5	26.2	27.7	29.1	30.3	31.3	32.2	32.9	33.7	34.4	34.9	35.5
CEDAR TS	1.7	3.8	6.0	8.3	10.1	11.9	13.7	15.2	16.5	17.7	18.7	19.6	20.4	21.1	21.8	22.2	22.7	23.2	23.6	24.0
HANLON TS	0.7	1.5	2.3	3.2	3.9	4.6	5.3	5.9	6.4	6.8	7.2	7.6	7.9	8.2	8.4	8.6	8.8	9.0	9.1	9.3
FERGUS TS	0.7	1.5	2.4	3.3	4.0	4.8	5.5	6.1	6.6	7.1	7.5	7.9	8.2	8.5	8.7	8.9	9.1	9.3	9.4	9.6
DETWEILER TS/KITCHENER #9	0.5	1.1	1.8	2.5	3.0	3.5	4.0	4.5	4.9	5.2	5.5	5.8	6.0	6.2	6.4	6.6	6.7	6.9	7.0	7.1
KITCHENER #3	0.9	2.0	3.1	4.3	5.2	6.2	7.1	7.9	8.6	9.2	9.7	10.2	10.6	11.0	11.3	11.5	11.8	12.1	12.2	12.4
KITCHENER #4	1.2	2.6	4.1	5.7	6.9	8.2	9.4	10.4	11.4	12.1	12.8	13.5	14.0	14.5	14.9	15.3	15.6	16.0	16.2	16.5
KITCHENER #8	0.5	1.1	1.7	2.4	2.9	3.4	3.9	4.4	4.7	5.1	5.4	5.6	5.9	6.1	6.2	6.4	6.5	6.7	6.8	6.9
KITCHENER #1	0.4	0.8	1.2	1.7	2.1	2.5	2.8	3.2	3.4	3.7	3.9	4.1	4.2	4.4	4.5	4.6	4.7	4.8	4.9	5.0
KITCHENER #7	0.6	1.4	2.2	3.1	3.7	4.4	5.0	5.6	6.1	6.5	6.9	7.2	7.5	7.8	8.0	8.2	8.4	8.6	8.7	8.8
KITCHENER #5	1.3	2.9	4.5	6.3	7.6	9.0	10.3	11.5	12.5	13.4	14.2	14.9	15.5	16.0	16.5	16.8	17.2	17.6	17.8	18.1
KITCHENER #6	1.2	2.5	4.0	5.5	6.7	7.9	9.1	10.1	11.1	11.8	12.5	13.1	13.7	14.1	14.5	14.9	15.2	15.5	15.7	16.0
ELMIRA TS	0.6	1.3	2.0	2.8	3.4	3.9	4.5	5.0	5.5	5.9	6.2	6.5	6.8	7.0	7.2	7.4	7.5	7.7	7.8	8.0
RUSH MTS	0.7	1.5	2.3	3.2	3.9	4.6	5.3	5.9	6.4	6.9	7.3	7.7	8.0	8.2	8.5	8.7	8.9	9.1	9.2	9.3
SCHEIFELE TS	2.5	5.5	8.8	12.1	14.8	17.4	20.0	22.2	24.2	25.9	27.4	28.8	29.9	30.9	31.9	32.6	33.3	34.0	34.5	35.1
WATERLOO #3	0.7	1.5	2.4	3.3	4.0	4.7	5.4	6.0	6.5	7.0	7.4	7.7	8.1	8.3	8.6	8.8	9.0	9.2	9.3	9.5
PUSLINCH DS	0.4	0.9	1.4	2.0	2.4	2.9	3.3	3.7	4.0	4.3	4.5	4.8	4.9	5.1	5.3	5.4	5.5	5.6	5.7	5.8
Total	**22.8**	**49.8**	**78.7**	**109.0**	**132.7**	**156.2**	**179.7**	**199.7**	**217.5**	**232.1**	**245.9**	**258.3**	**268.6**	**277.6**	**286.0**	**292.5**	**298.8**	**305.5**	**309.8**	**315.4**

C.2 Historical Conservation Savings

At the local level, within the KWCG area significant conservation results have been achieved. Table C2-1 provides a summary of the net peak demand program savings by each of the KWCG LDCs in 2011, the first year of the 2011-2014 OPA Contracted Province-Wide CDM Programs. It is important to note that Hydro One Distribution serves a significant number of customers outside of the KWCG area, and as such only a portion of their achievement would have taken place in the KWCG region. Conservation savings from non-program activities, including codes and standards, are not included in the savings presented in Table C2-1.

Additional details on LDC conservation savings in 2011 can be found in their 2011 CDM Annual Reports, which were filed with the OEB. LDCs are expected to file their 2012 CDM Annual Report in September 2013.

Table C2-1: Summary of LDC Historical Conservation Program Savings 2011

LDC	2011 (MW)	Link to LDC 2011 CDM Annual Report
Kitchener-Wilmot Hydro	4.6	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0215/KitchenerWilmot_2011_Annual_CDM_Report.pdf
Waterloo North Hydro	2.1	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0215/WaterlooNorth_2011_Annual_CDM_Report.pdf
Cambridge and North Dumfries Hydro	2.5	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0215/CambridgeNorthDumfries_2011_Annual_CDM_Report.pdf
Guelph Hydro Electric Systems	3.4	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0215/Guelph_2011_Annual_CDM_Report.pdf
Hydro One Distribution	35.1	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0215/HONI_2011_Annual_CDM_Report.pdf

C.3 Conservation Subcommittee

In April 2012, a Conservation subcommittee to the KWCG Working Group was established. The subcommittee was comprised of CDM representatives from each of the LDCs in the region, and OPA Conservation and Power System Planning staff. The primary objective of the subcommittee was to provide additional support, as necessary, to LDCs in meeting their local conservation targets. The final deliverable of the subcommittee was an Action Plan that was developed to facilitate the successful implementation of the 2011-2014 OPA Contracted Province-Wide CDM Programs in KWCG. The subcommittee concluded its work in December 2012, with an OPA business development resource identified to continue working with the LDCs' CDM staff on their achievement towards their CDM targets. The subcommittee can be reconvened on an ad hoc basis to be consulted on a range of potential longer-term cost effective CDM opportunities options in the region.

Appendix D

Generation in the KWCG Area

D.1 Capacity Contribution

For the planning purposes, capacity contribution is the amount of installed generation capacity that can be relied on to meet demand during peak hours. Since each type of distributed generation exhibits unique behaviour, different capacity contribution assumptions were used for wind, solar, hydro electric and biomass/co-generation to determine the effective capacity for the distributed generation resources in the KWCG. Due to the intermittent nature of wind and solar, not all of the installed capacity is expected to be available during peak hours and can only be estimated on probabilistic basis.

Where local distribution companies in the KWCG area had information on the capacity contributions of specific distributed generation facilities this information was used. For other distributed generation facilities in the KWCG area, Table D1-1 summarizes the capacity contribution to provincial peak demand, the data sources and methodology used to determine capacity contribution for wind, solar, hydro electric and biomass. Given that the historical provincial summer peak and the peak in the KWCG area, generally coincident, for the purpose of the KWCG regional planning study, the Working Group agreed that it would be reasonable to apply the capacity contribution for provincial level planning.

Table D1-1: Distributed Generation Capacity Contribution

Resource Type	Capacity Contribution	Data Source	Methodology
Wind	14 %	Wind Profiles from AWS Truepower	In order to calculate the effective wind generation availability on today's system, an analysis was performed using Multi-Area Reliability Simulation (MARS) model[1] to determine the amount of additional gas generation required to maintain the same level of reliability under the scenario with no wind resources in-service. The capacity contribution of wind is determined by calculating the ratio of the gas generation to the total amount of wind resource installed on the system.
Solar	30 %	Solar Profiles from AWS Truepower	The capacity contribution of solar generation depends on both random and predictable elements, such as cloud cover and sunset/sunrise times. The Multi-Area Reliability Simulation (MARS) model[1] was used to determine the strongest correlation between peak demand and solar generation, which generally occurs during the summer months of June, July, and August. The summer capacity contribution for solar is calculated based on the average of solar generation production during the top 10% of demand hours in June, July and August.
Biomass & Co-generation	98 %	Information from IESO Market Participants	The capacity contribution from thermal resource, including biomass, is derived from information provided by the IESO market participants and average values from public sources [2]. It can vary depending on site specific factors such as the age and condition of the generator.
Hydro	71%	Historical Hydroelectric Production Output (1999-2009)	An analysis was performed to determine the historical hydroelectric production output (1991-2009) coincident to provincial weekly peak demand period for each month. To estimate the capacity contribution for hydroelectric resources, the sum of the median hydroelectric production and the operating reserve during the peak demand period is divided by the total installed capacity of hydroelectric resources in Ontario.

Note:

(1) For intermittent resources, such as wind and solar, a probabilistic simulation model was used to effectively determine capacity contributions. This model, the Multi-Area Reliability Simulation (MARS), assesses the reliability of the Ontario electricity system. The MARS model calculates power system reliability indices by simulating probabilistically uncertainty in the load forecast and generator availability until specified convergence criteria are met.

(2) The assumption for 98% for biomass based on information from a 2004 NREL public report http://www.nrel.gov/docs/fy04osti/35947.pdf

D.2 Existing and Committed Distributed Generation

Distributed sources of generation play an active part in meeting the supply needs in Ontario. Distributed generation ("DG") refers to small-scale power generation which is located close to where the electricity is consumed. DG would reduce the need for other reinforcement measures in the KWCG area. This study included DG resources that currently exist, have an executed contract with the OPA, or are the subject of a government directive. These are non-discretionary resources in the resource mix.

Existing Distributed Generation

KWCG area has four existing, non OPA contracted distributed renewable generators, two of which the area LDCs report as providing dependable capacity during the hours of peak demand:

(i) Guelph City's Eastview landfill site - a distribution connected generator connected to Campbell TS which supplies 1.78 MW at peak demand.

(ii) Stone Road DG project in Guelph - a distribution connected generator connected to Cedar T7/T8 and supplies 0.88 MW at peak demand.

(iii) Kuntz Electroplating in Kitchener - This generator is connected to the 13.8 kV bus at Kitchener MTS #3 and is not providing any dependable capacity at peak.

(iv) Residential wind generator in Wilmot - This generator is connected to the 8.32 kV bus at Detweiler TS and is not providing any dependable capacity at peak.

Committed Distributed Generation

In May 2009, Ontario's Green Energy Act (GEA) established Ontario's commitment to green energy and energy from renewable resources in particular. In accordance with the GEA, the OPA launched a Feed-in Tariff (FIT) program that provides guaranteed prices for renewable energy generation for a twenty year period. The FIT program has led to a high amount of interest in renewable generation development in the province. Prior to the launch of FIT, Renewable Energy Standard Offer Program (RESOP) was a standard offer program designed to stimulate the development of small-scale (under 10 MW) renewable energy opportunities.

The contribution of renewable resources is relatively less during peak periods due to their intermittent nature and therefore their contribution during peak periods is less than their installed capacity. As such, only a portion of installed capacity of the distributed generation resources can be counted on during peak hours. In order to take into account the contribution of distributed generation in the KWCG area, a capacity contribution factor (refer Appendix D.1 for more information about capacity contribution factor) is applied to the installed capacity of existing and committed distributed generation resources in the KWCG area. The table below provides a summary of capacity contribution of the existing and committed distributed generation resources in the KWCG area.

Table D2-1: KWCG Distributed Generation Capacity Contribution by TS

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Cambridge #1	0.3	0.3	0.3	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Galt TS	0.1	0.1	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Preston TS	0.1	0.1	0.1	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Cambridge #2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cambridge #3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Campbell TS	3.2	3.2	3.3	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Cedar TS T1/T2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cedar TS T7/T8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Hanlon TS	0.0	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Arlen MTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Detweiler TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener #1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Kitchener #3	0.0	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Kitchener #4	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Kitchener #5	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Kitchener #6	0.0	0.0	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Kitchener #7	0.1	0.1	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Kitchener #8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kitchener #9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Elmira TS	0.0	0.0	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Rush MTS	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Scheifele TS	0.0	0.0	0.2	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Waterloo #3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Snider TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bradley TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fergus TS	4.6	4.7	6.1	6.4	6.4	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Puslinch DS	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wolverton DS	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**14.4**	**14.5**	**20.1**	**23.2**	**23.4**	**24.1**	**24.1**	**24.1**	**24.1**	**24.1**	**24.1**	**24.1**	**24.1**	**24.1**	**24.1**	**24.1**	**24.1**	**24.1**	**24.1**	**24.1**

D.3 Generation Cost Assessment

Step 1: Estimate the All-In Annualized Cost of Typical DG Alternatives and the Recommended Transmission Alternative

All-in annualized costs represent the annual portion of the total cost of building and operating a particular asset; they are determined by allocating the total costs over the asset's useful life. The all-in annualized costs of typical DG alternatives and the recommended transmission reinforcements are shown below in Table 1 in 2012 $/MW-month; the assumptions underpinning these costs are described below.

a) All-in annualized costs include capital, fixed, variable and fuel costs of the distributed generation alternatives, and capital and fixed costs of the recommended transmission reinforcements. Input costs for the distributed generation alternatives is informed by a combination of: OPA program parameters (e.g. from CHPSOP and FIT 2.0), publically available capital and operating cost information and planning assumptions that include annual capacity factors, heat rates and fuel commodity costs. The cost of the recommended transmission reinforcements were provided by Hydro One.

b) All-in annualized costs are derived using a useful life of 20 years for generation assets, and 45 years for transmission assets.

c) The all-In costs do not include costs of land or additional transmission reinforcements that may be required to connect distributed generation facilities, or to address any remaining supply capacity needs that could arise from generation facilities being sited in non-optimal locations (from a transmission perspective).

d) All-in annualized costs are converted from 2012 $/MW-yr to 2012 $/MW-month by dividing by 12.

Table 1

Estimated All-In Annualized Costs of Typical DG Alternatives and the Recommended Transmission Reinforcements	2012 $/MW-month
Combined Heat and Power (CHP) on Natural Gas	40,000
Peaking Natural Gas	13,000
Solar - Ground Mount	29,000
Solar - Rooftop (10-250 kW)	45,000
Recommended Transmission Reinforcements	2,200

Step 2: Estimate the Present Value Total Cost of Each of the Alternatives

The purpose of this step is to estimate the present value of the annual cash flows associated with building and operating the distributed generation alternatives and recommended transmission reinforcements (refer to Step 1 above), and to reflect the value of the distributed generation in meeting broader system peak capacity needs (that are expected to emerge in 2018) as well as the energy that would be displaced in the system through the operation of the distributed generation alternative in the local area. The estimated present value of the alternatives is presented below in Table 3 in 2012$; the assumptions underpinning these costs are described below.

a) The installed amount of distributed generation required to meet the peak capacity need in South-Central Guelph, Kitchener-Guelph and Cambridge was calculated using the magnitude of the area's need by 2023 and the capacity contribution of each of the distributed generation alternatives. Refer to Table 2 below.

Table 2

Peak Capacity Needs (MW) by 2023 in: South-Central Guelph Kitchener-Guelph Cambridge	**186**
DG Alternative	**Installed Capacity (MW) Required to Meet Peak Capacity Needs**
Combined Heat and Power (CHP) on Natural Gas	190
Peaking Natural Gas	190
Solar - Ground Mount	620
Solar - Rooftop (10-250 kW)	620

b) The required installed capacity for each of the distributed generation alternatives was multiplied by its corresponding all-in annualized cost to represent the annual cash flow associated with building and operating the facility in 2012 $. For the recommended transmission reinforcements, the all-in annualized cost was multiplied by 186 MW - the peak needs in 2023 in South-Central Guelph, Kitchener-Guelph and Cambridge.

c) The annual value of displaced system energy that would occur through distributed generation operation was determined by multiplying an estimate of the system marginal cost by an estimate of the amount of energy that would be produced by each of the distributed generation alternatives (based on planning assumptions). The annual value of displaced energy was subtracted from the annual cost described in step b) above; the present value of the resultant cash flows to 2023 is shown in COLUMN A of Table 3, below.

d) The value that distributed generation can provide to the broader system in contributing to peak capacity needs was factored in by including the cost of building and operating a peaking natural gas facility (sized at 190 MW as per Table 2) to the cost of the recommended transmission reinforcements, starting in 2018 (the time frame in which peaking needs are expected to emerge). In terms of technical and cost considerations, a peaking natural gas facility is assumed to be the most appropriate resource to meet the system's peak capacity needs. This cost is represented in COLUMN B of Table 3, below.

e) The total estimated present value cost of each alternative is determined by adding COLUMN A and COLUMN B of Table 3, below. The relative performance of the alternatives, compared to the recommended transmission reinforcements, is shown in COLUMN C of Table 3 below.

f) A social discount rate of 4 percent was used to estimate the present value costs.

Table 3 (2012 $ in Millions)

	COLUMN A	COLUMN B	COLUMN A+B	COLUMN C
Typical DG Alternatives and the Recommended Transmission Reinforcements	**Estimated PV of All-In Costs & Energy Displacement to 2023**	**Estimated PV of All-In Cost for Additional Generation (@ peaking natural gas) Required in the Rest of the Province Starting in 2018**	**Total Estimated PV Cost**	**Delta from Recommended Transmission Reinforcements**
Combined Heat and Power (CHP) on Natural Gas	395	-	395	250
Peaking Natural Gas	160	-	160	15
Solar - Ground Mount	1,245	-	1,245	1,100
Solar - Rooftop (10-250 kW)	2,045	-	2,045	1,900
Recommended Transmission Reinforcements	**45**	**100**	**145**	**-**

D.4 History of Large Gas-Fired Generation Development in the KWCG Area

The OPA and Hydro One began to assess the needs and options of the KWCG area, based on the ORTAC criteria as part of the 2007 Integrated Power System Plan (IPSP). Based on the study assumption at that time, along with conservation, distributed generation and transmission resources, a 450 MW gas-fired generation located near the Preston station in Cambridge was recommended to address the needs in the Cambridge area.

In the summer of 2010, a broader regional planning study of the Kitchener-Waterloo-Cambridge-Guelph area was undertaken. This study updated demand forecasts for the region, and confirmed the needs in the Cambridge area (see Section 5). Based on the latest findings from this report, the recommended integrated solution of conservation, distributed generation and transmission reinforcements outlined in Section 8 will address the near- and medium-term reliability needs of the KWCG area. Additional generation, both small and large-scale, will be considered as a potential option to maintain a reliable supply of electricity to the KWCG. Additional generation, both small and large-scale, will be considered as a potential option to maintain a reliable supply of electricity to the KWCG area over the longer-term (beyond 2023).

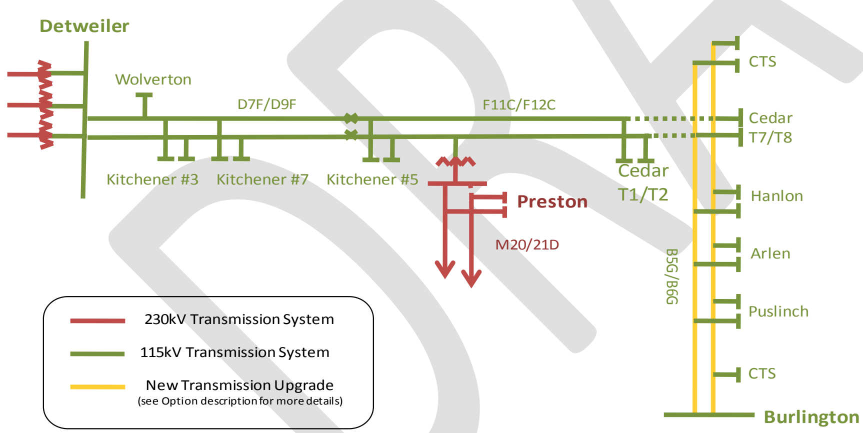
Appendix E

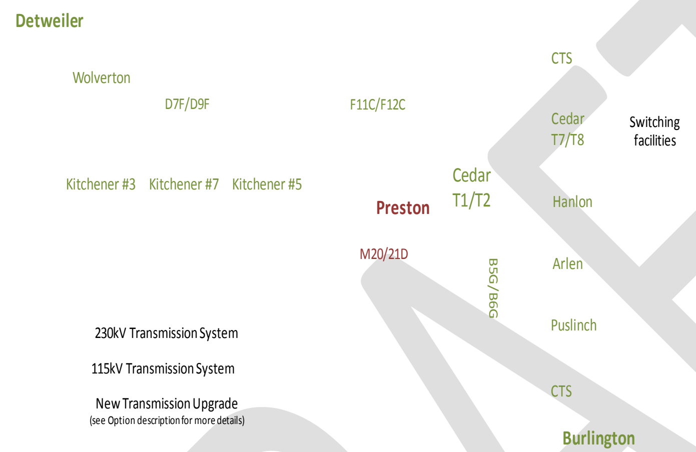
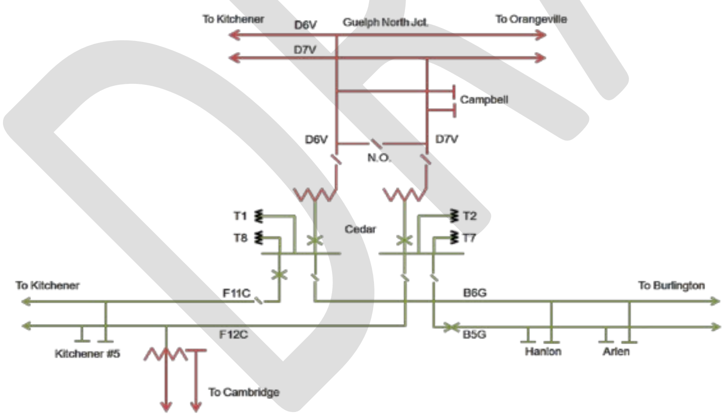
Transmission System in the KWCG Area

E.1 Transmission Options to Address Near- and Medium- Term Needs in the KWCG Area

In addition to conservation and generation, the Working Group has considered various transmission options to address the near-medium term needs in the KWCG area. Specifically, Table E1-1 describes the three transmission options considered to address the near-medium term supply capacity in South-Central Guelph and Kitchener-Guelph subsystem.

Table E1-1: Transmission Options to Address Near- and Medium-Term Supply Capacity in South-Central Guelph and Kitchener-Guelph

Options	Diagram	Description	High-Level Cost Estimates
Reinforcing Supply from the South		Re-conductor existing B5/6G transmission line with a higher rated conductor or convert the existing B5G/B6G supply to 230kV (Approx. 42 km)	Over $200 M

Options	Diagram	Description	High-Level Cost Estimates
Reinforcing supply from the West		(1) Rebuilding the existing 115kV Kitchener-Guelph subsystem (D7F/D9F and F11C/F12C) to a higher rated 115kV or 230kV facility (Approx. 33km) (2) Installing switching facilities at Cedar TS	Over $130M
Reinforcing supply from the North		(1) Upgrade the existing 115kV transmission line between Campbell TS and CGE Jct to a double-circuit 230kV transmission line (Approx. 5km) (2) Install two 230/115kV autotransformer and four new 115 kV circuit breakers at Cedar TS (3) Transfer an existing directly connected customer in the area to the distribution system and advance the relocation of the existing Hydro One Distribution operating centre	$80M

Appendix F

Detailed Technical Studies and Analysis

F.1 Base Case Setup and Assumptions

The system studies for this plan were conducted using PSS/E Power System Simulation software. The reference PSS/E case was adapted from the 2015 base case that was produced by the IESO for the 2010 Northeast Power Coordinating Council (NPCC) Review. With respect to the transmission system, summer ambient conditions of 35°C and 0-4 km/hr wind for overhead transmission circuits was assumed in this study. For transformers, 10-day limited time ratings (LTRs) are respected under post-contingency conditions.

Bulk System Assumptions

This load flow includes all eight Bruce units and the new 500kV double-circuit line between the Bruce Complex and Milton SS. All the units at Darlington are assumed to be in-service, and all of the units at Pickering GS are assumed to be unavailable due to their scheduled retirement as early as 2015.

While for local area supply the expected capacity contribution of distributed generation at peak is used, for the purposes of establishing bulk system flows it is important to address the spatial and temporal diversity of wind resources installed throughout the Ontario system. Wind generation in the Bruce and other parts of southwestern Ontario will have an impact on the bulk system flows into the KWCG area, and therefore is an important consideration where establishing the network flows for base transfer. For the purposes of the study, for the Bruce area, six connection points (each corresponding to a wind site modelled in the AWS Truepower 2010 Wind Study[1]) were used to represent transmission-connected FIT wind generation in the Bruce area. The total installed capacity in this area modelled was 1,700 MW. Using the hourly wind power output data set spanning ten years provided by AWS Truepower, it was found that at 95% of time (taking into account the OPA's 5% of time congestion metric), wind output in the Bruce area is about 63%.

To represent other transmission-connected FIT wind generation which would also have an impact on the flow into the KWCG area, three other connection points were identified in the southwest to represent 450

[1] A study conducted by AWS Truepower consultants for the OPA to enable better wind modelling to account for wind diversity

MW of FIT projects. These connection points were Buchanan, Chatham, and Sarnia. It was determined that the wind output at 95% of time for these connection points 62% to 71%.

Accordingly, the following changes were made to the generation dispatch in the loadflow case:

- The addition of 1,700 MW of new wind-turbine capacity, at a capacity factor of 0.63MW, within the Bruce area. This represented approximately 1,070 MW of new generation capacity.
- Similarly, a capacity factor of 0.63 was applied to the existing 1,080 MW of wind-turbine generation in the Bruce area. The existing wind-turbine facilities therefore represented approximately 680 MW of generation capacity.
- In the south-west, a further 550 MW of new renewable generation was added, at capacity factors of between 1.0 for solar and 0.6 for wind, for a net total of approximately 390 MW of generation capacity.
- To partially off-set this additional generation capacity, the transfer to Hydro Quebec via the Outaouais HVdc connection was set at 1,250 MW and the output from Darlington GS was reduced by 500 MW.

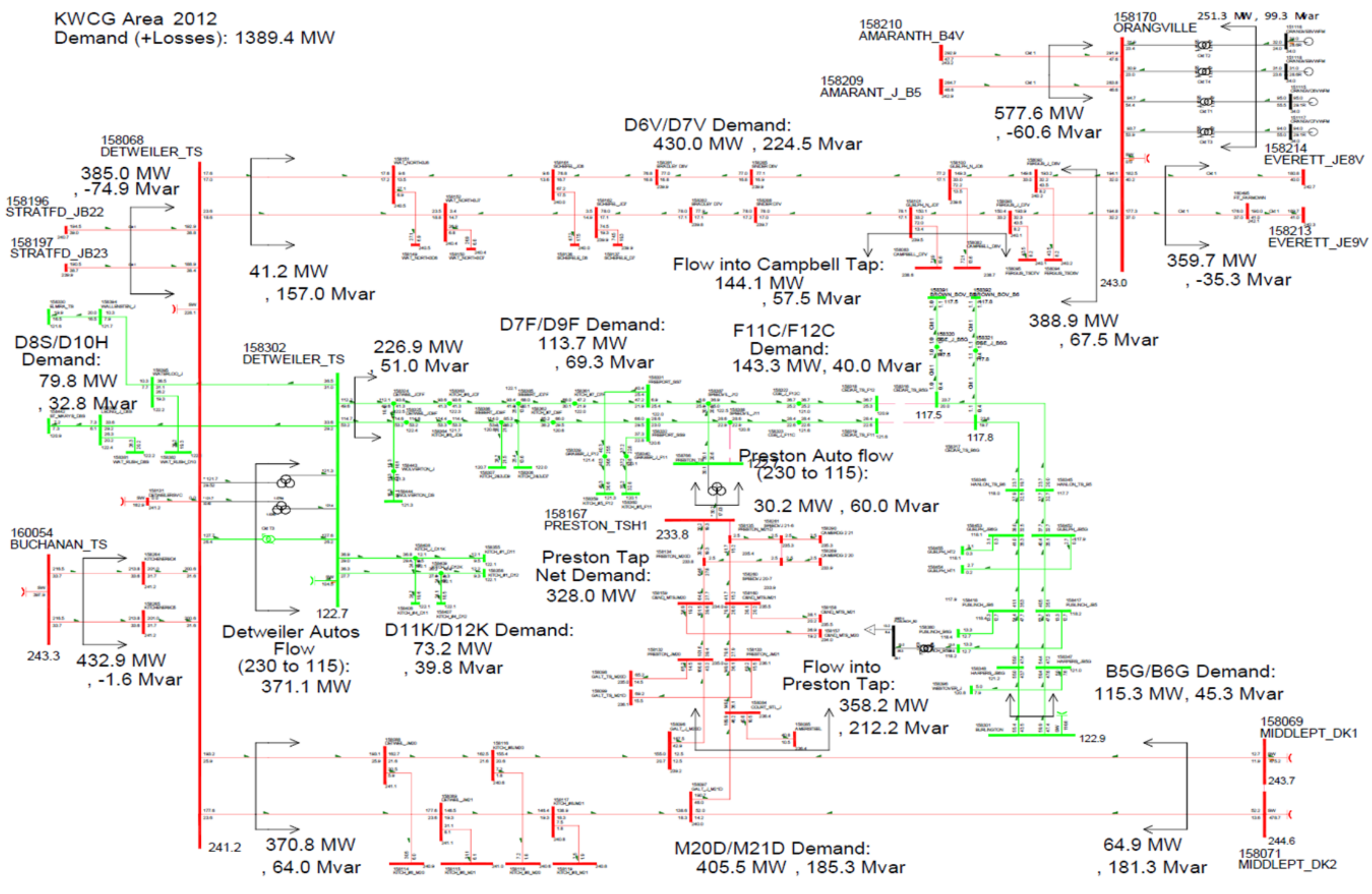
<u>Local Area Assumptions</u>

In additional to the bulk systems assumptions, the base case includes the following recent changes and specific characteristics of the KWCG transmission system:

- The Government's clean energy initiative to eliminate all coal plants in the province by 2014
- The introduction of the GEGEA, and the associated award of FIT and microFIT contracts in KWCG and other southwest Ontario areas during the FIT Launch and Post-Launch Periods
- The installation of the Preston TS autotransformer
- The approval of a new Bruce to Milton 500 kV transmission line
- Increase output from the Bruce Nuclear Generating Station (total output of 6,300 MW)
- The installation of a 350 MVAr SVC at Detweiler TS
- 230 kV and 115 kV capacitor banks in the KWCG area
- Uprating of the F11C/F12C circuits following tower raising work performed by Hydro One
- It also assumes the work at Burlington TS is completed.

The figure below shows the snapshot of the KWCG area load flow case using 2012 peak demand data

Table F1-1: KWCG 2012 Peak Loadflow Case



F.2 Application of IESO Planning Criteria

In accordance with ORTAC, the system must be designed to provide continuous supply to a local area, under specific transmission and generation outage scenarios. The ORTAC criteria governing supply capacity for local areas are presented in Table F2-1. The performance of the system in meeting these conditions is used to determine the supply capability of an area for the purpose of regional planning. Supply capability is expressed in terms of the maximum load that can be supplied in the local area with no interruptions in supply or, under certain permissible conditions, with limited controlled interruptions as specified by ORTAC.

Table F2-1: ORTAC Criteria for Supply Capacity with Local Generation

Pre-contingency		Contingency[1]	Thermal Rating	Maximum Permissible Load Rejection
All transmission elements in-service	Local generation in-service	N-0	Continuous	None
		N-1	LTE[2]	None
		N-2	LTE[2]	150 MW
	Local generation out-of-service	N- 0	Continuous	None
		N-1	LTE[2]	150 MW[3]
		N-2	LTE[2]	>150 MW[3] (600MW total)

1. N-0 refers to all elements in-service; N-1 refers to one element (a circuit or transformer) out of service; N-2 refers to two elements out of service (for example, loss of two adjacent circuits on same tower, breaker failure or overlapping transformer outage),N-G refers to local generation not available (for example, out of service due to planned maintenance).
2. LTE: Long-term emergency rating. 50-hr rating for circuits, 10-day rating for transformers.
3. Only to account for the capacity of the local generating unit out of service

In the event of a major outage, such as a contingency on a double-circuit tower line resulting in the loss of both circuits, ORTAC requires that the transmission system be designed to minimize impact of supply interruptions to customers in two ways: by limiting the amount of load that would be affected by the outage; and by restoring power to those affected within a reasonable timeframe. ORTAC specifies that no more than 600 MW of load should be interrupted in the event of a major outage. For load pockets less than 600 MW, load lost during a major outage should be restored within the following timeframes:

- All load lost in excess of 250 MW must be restored within half an hour;
- All load lost in excess of 150 MW must be restored within four hours; and
- All load must be restored within eight hours.

F.3 Contingencies

A detailed list of the contingencies considered when applying this criteria in the KWCG study is outlined below in Table F3-1.

Table F3-1: Contingencies Considered in the KWCG Study

Subsystem	N-1	N-2	(N-1)-1
South-Central Guelph 115 kV	B5G B6G	B5G + B6G	
Kitchener-Waterloo-Guelph 115 kV	D9F D7F F11C F12C D11K D12K D8S D10H	D7F + D9F F11C + F12C D11K + D12K D8S + D10H	F12C + D9F F12C + D7F F11C + D7F F11C + D9F
Kitchener-Cambridge 230 kV	M20D M21D Preston Autotransformer	M20D + M21D	
Waterloo 230 kV	D6V D7V	D6V + D7V	

F.4 Needs Assessment - Capacity to Meet Demand

South-Central Guelph 115 kV Subsystem

Today, the double-circuit 115 kV transmission line (B5G/B6G) supplying South-Central Guelph from Burlington TS has a load meeting capability of approximately 100 MW. This limit is based on the violation of the voltage change at Hanlon LV bus the B5G or B6G circuit following the loss of the companion circuit. According to the ORTAC criteria, the voltage decline on the LV bus should not exceed 5% following a contingency. If the loading on B5G/B6G approaches 100 MW, the LV voltage at Hanlon drops from 14.7 kV to 13.9kV following the loss of B5G or B6G (5.4% voltage decline). Based on the summer peak demand in the South-Central Guelph area, this supply capacity was exceeded in 2012.

Figure F4-1: South-Central Guelph 115 kV Subsystem

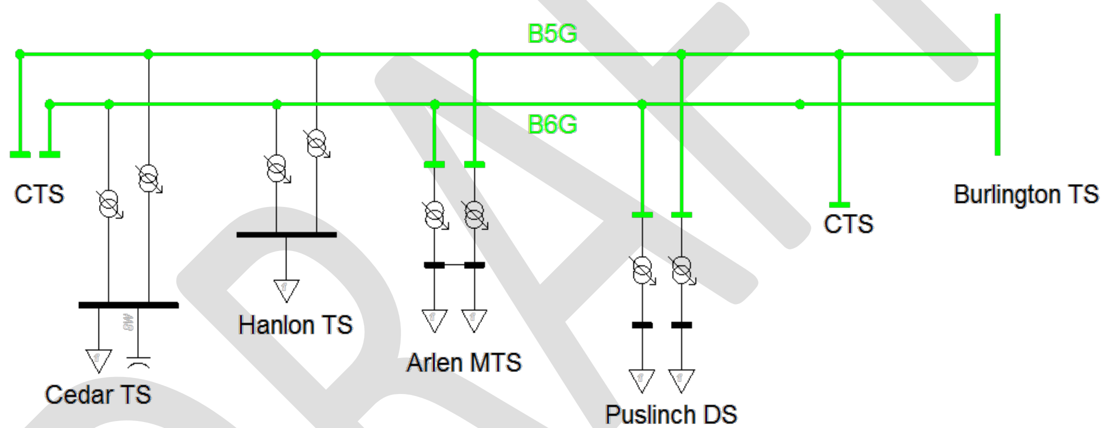


Figure F4-2: South-Central Guelph 115 kV Subsystem - Pre-Contingency (100 MW Load on B5/6G)

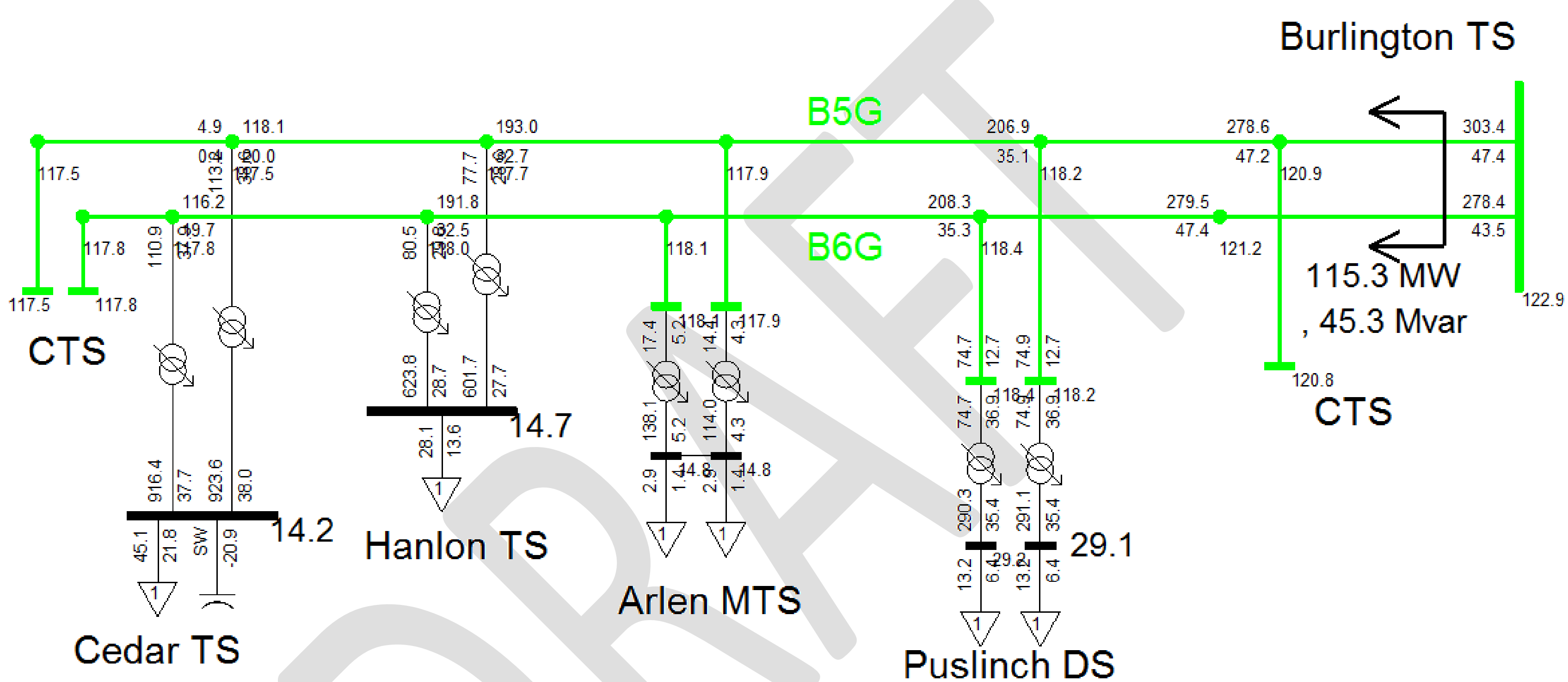
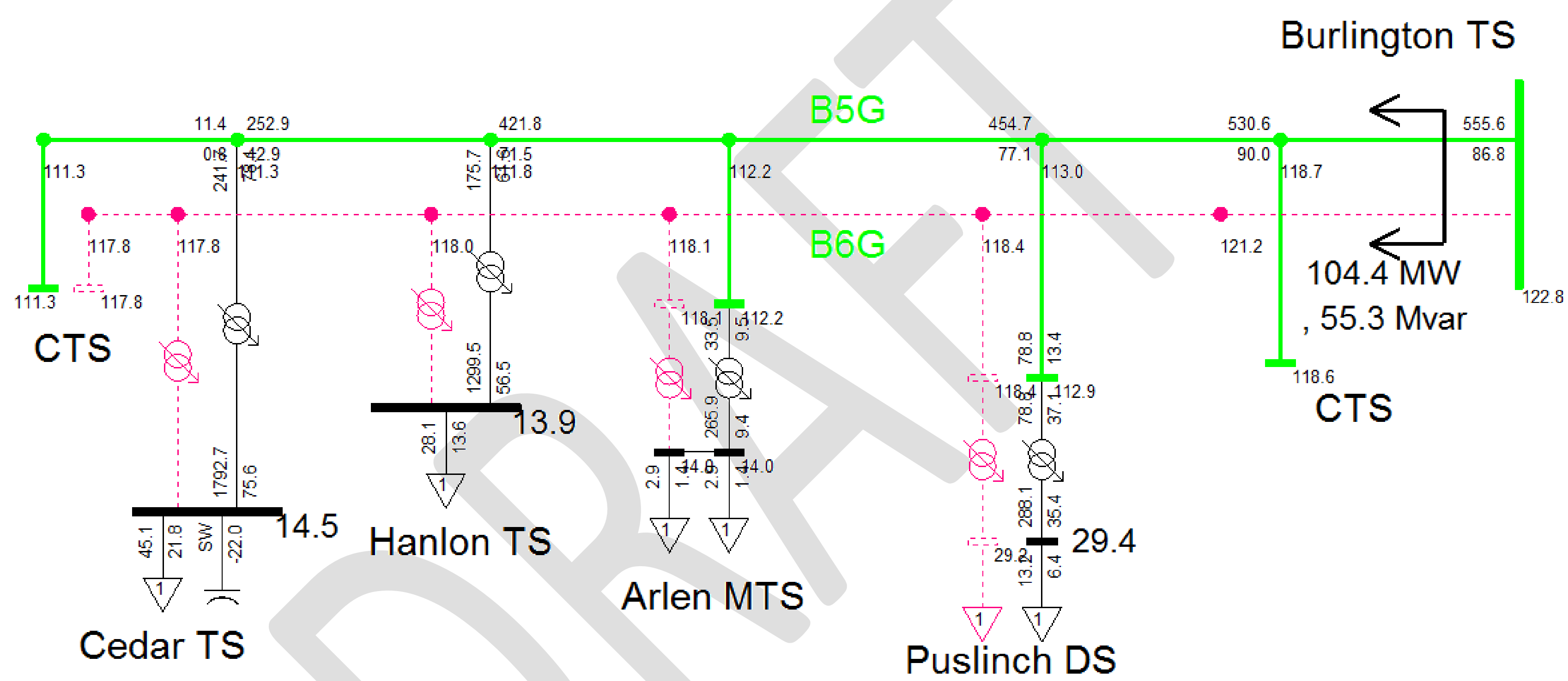


Figure F4-3: Post Contingency (100 MW Load on B5/6G) – Loss of B5G



Kitchener-Guelph115 kV Subsystem

Today, the Kitchener-Guelph area is supplied by one double-circuit 115 kV transmission line (D7F/D9F and F11C/F12C) from Detweiler TS and supported by the existing 230/115 kV autotransformer at Preston TS. Following the loss of the F12C circuit, the remaining transmission supply to the area has a load meeting capability of approximately 260 MW. This limit is based on thermal overloading of the D9F circuit from Detweiler TS. Based on the forecast electricity demand for the area, peak demand is expected to reach the 260 MW supply capacity limit in 2013.

Figure F4-4: Kitchener-Guelph 115 kV Subsystem

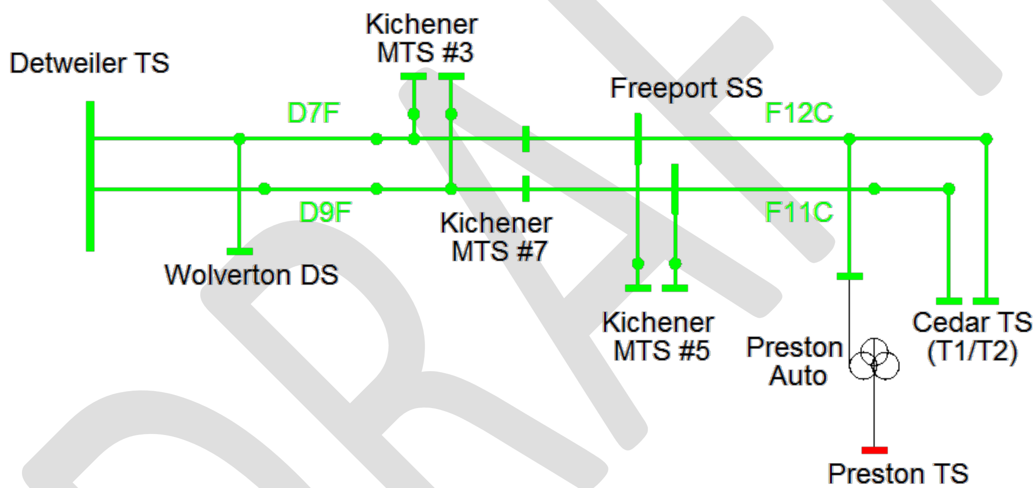


Figure F4-5: Kitchener-Guelph 115 kV Subsystem - Pre-Contingency (2019)

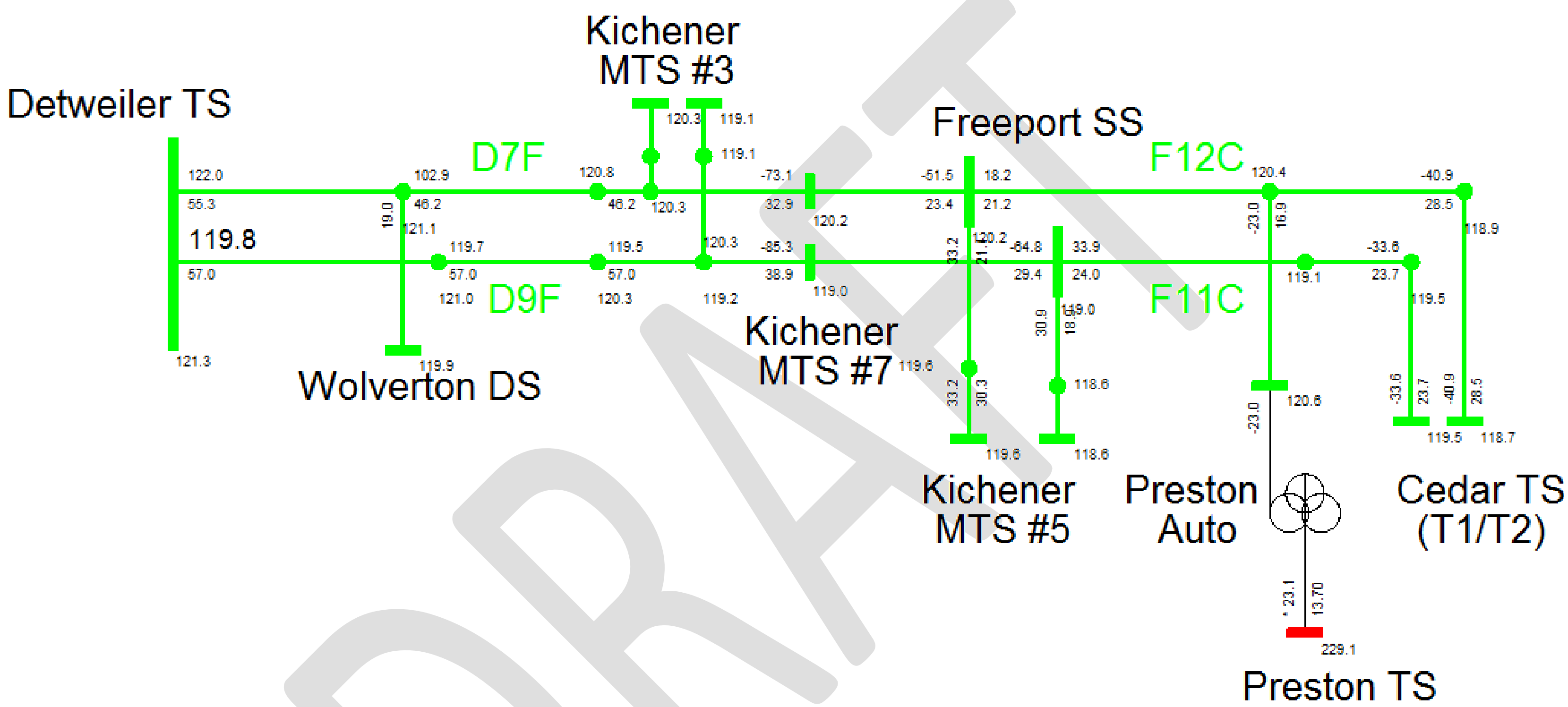
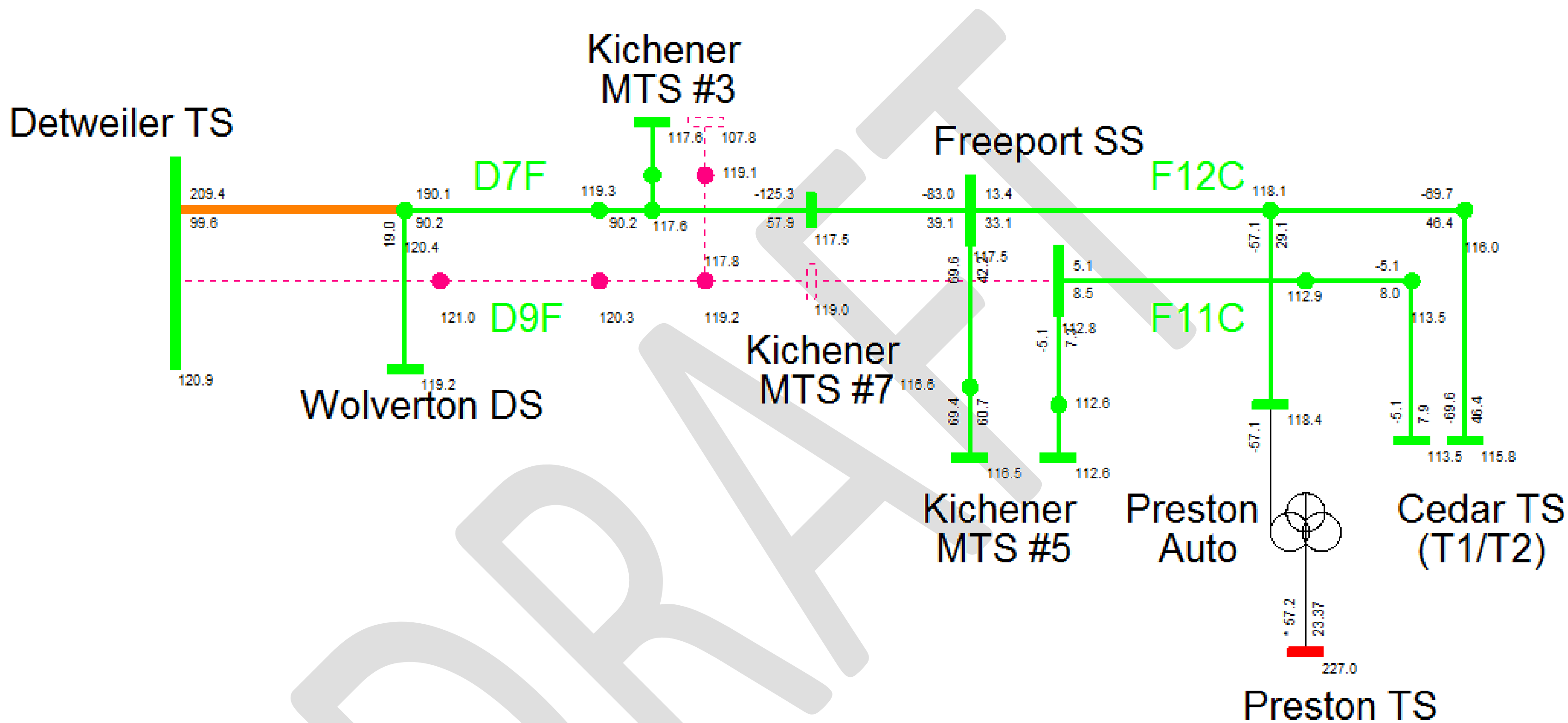


Figure F4-6: Kitchener-Guelph 115 kV Subsystem - Post-Contingency (2019) – Loss of D9F



Cambridge 230 kV Subsystem

Today, the Cambridge area is supplied by one double-circuit 230 kV transmission line (the Preston Tap) tapped off of the main 230 kV transmission line (M20D/M21D) between Detweiler TS and Middleport TS. Following the loss of the M20D circuit, the companion circuit on the Preston Tap has a load meeting capability of approximately 375 MW. This limit is based on the thermal overloading of the M21D circuit between Galt Junction and Preston Junction in Cambridge. Based on the forecast electricity demand for the area, peak demand is expected to reach the 375 MW supply capacity limit in 2013.

Figure F4-7: Cambridge 230 kV Subsystem

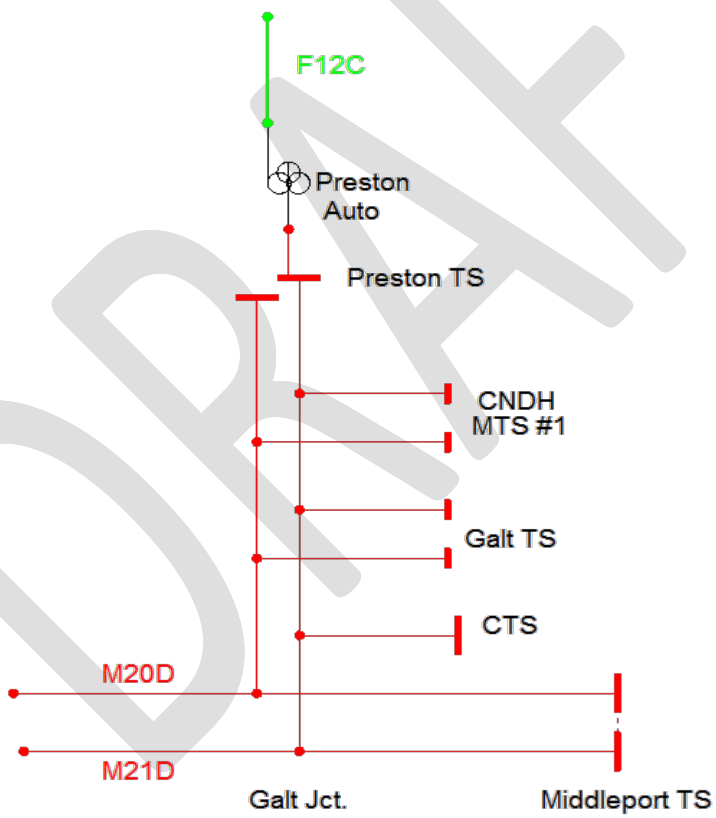


Figure F4-8: Cambridge 230kV Subsystem - Pre-Contingency (2013)

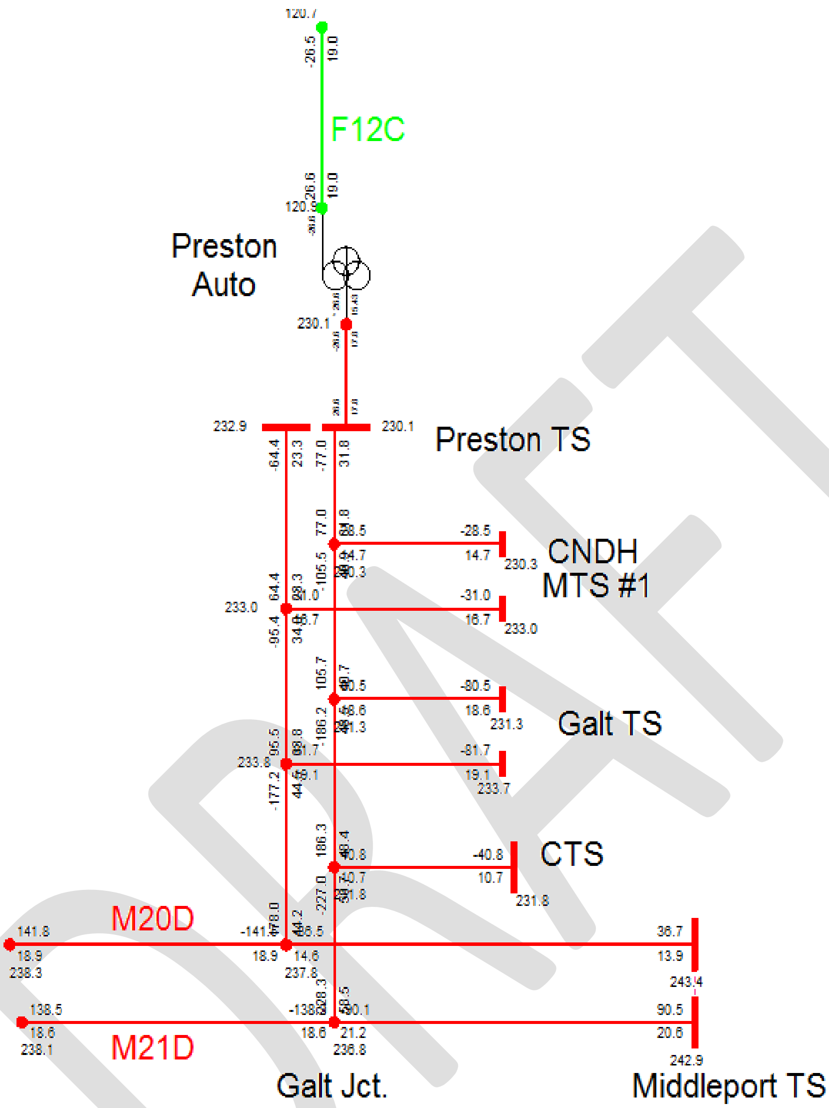
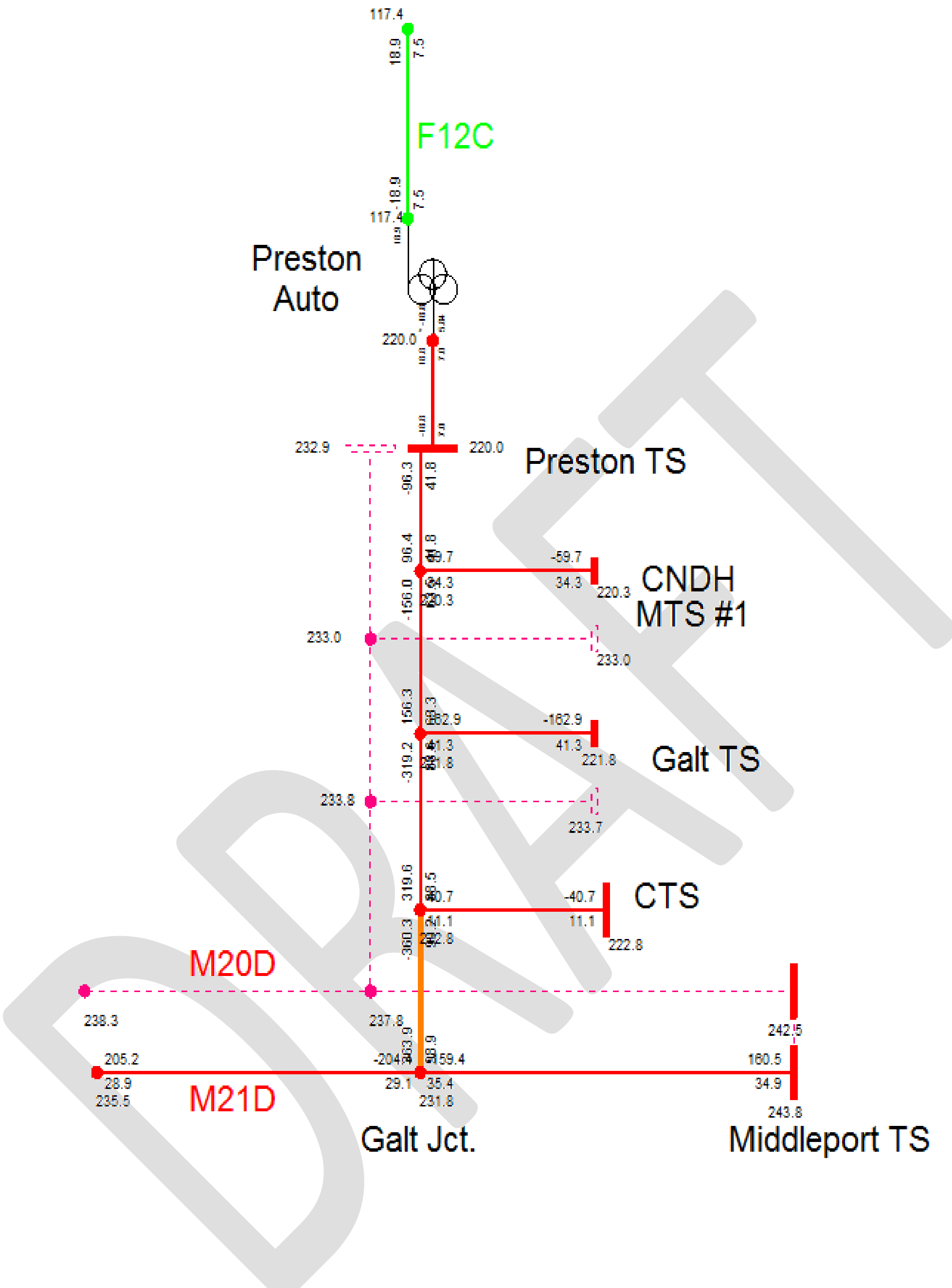


Table F4-9: Cambridge 230kV Subsystem - Post-Contingency (2013) – Loss of M20D



F.5 Needs Assessment - Minimize the Impact of Supply Interruptions

Waterloo-Guelph 230 kV Subsystem

Today, the Waterloo-Guelph area is supplied by an approximately 77 km double-circuit 230 kV transmission line (D6V/D7V) between Detweiler TS and Orangeville TS. In the event of the loss of both the D6V and D7V circuits, all load supplied by this transmission line (which exceeded 400 MW in 2012) will be interrupted. The existing system lacks the capability to restore power to these customers in accordance with the ORTAC criteria which specifies that all load interrupted over 250 MW must be restored within 30 minutes. A major outage of this type took place on February 29th, 2012 when a forced outage on one of the D6V/D7V circuits, coupled with scheduled maintenance on the companion circuit, resulted in the interruption of electricity supply for roughly three hours to approximately 350 MW of customers in parts of the cities of Waterloo, Kitchener and Guelph.

Figure F5-1: Waterloo-Guelph 230 kV Subsystem

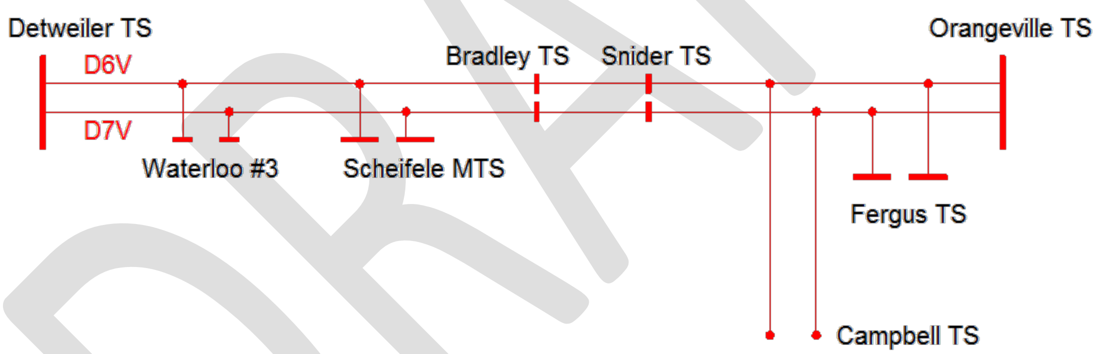


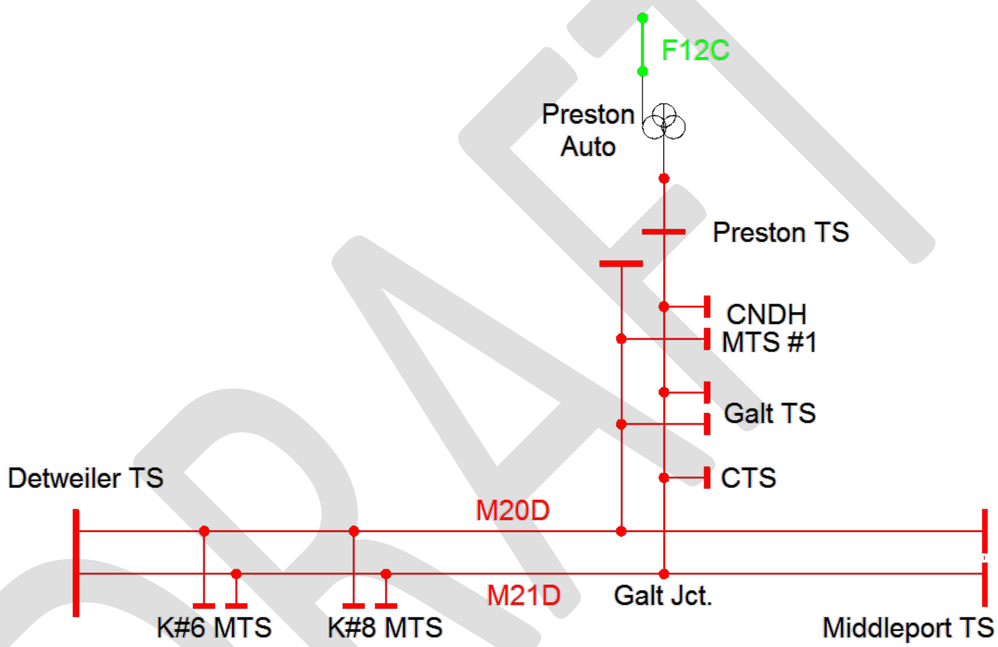
Table F5-1: Reference Demand Forecast Waterloo-Guelph 230 kV Subsystem

Demand (MW)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Waterloo 230kV	480	489	498	507	518	535	551	560	571	602	615	621	634	653	679	693	716	731

As shown in Table F5-1, over the medium- to longer-term (2022), demand supplied by the D6V/D7V circuits is expected to exceed 600 MW.

Kitchener and Cambridge 230 kV Subsystem

Figure F5-2: Kitchener and Cambridge 230 kV Subsystem



Today, the Kitchener and Cambridge system is supplied by an approximately 82 km double-circuit 230 kV transmission line (M20D/M21D) between Detweiler TS and Middleport TS, including the Preston Tap. In the event of the loss of both the M20D and M21D circuits, all load supplied by this transmission line (which was approximately 400 MW in 2012) will be interrupted. The existing 230/115 kV autotransformer and 230 kV disconnect switches at Preston TS can restore approximately 65 MW at Preston TS within half an hour following a major outage.

Figure F5-3: Kitchener and Cambridge 230 kV Subsystem - Pre-Contingnecy (2012)

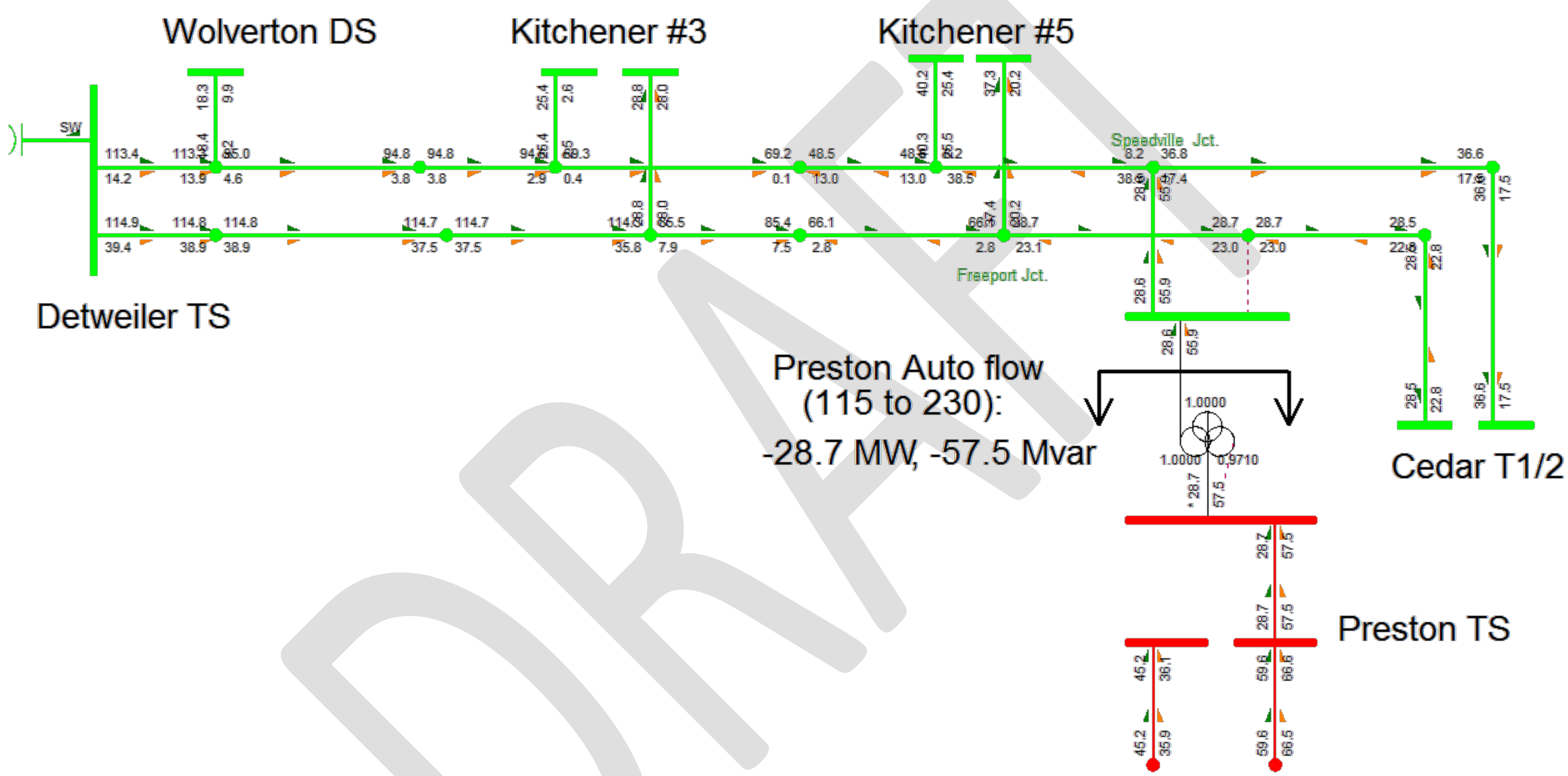
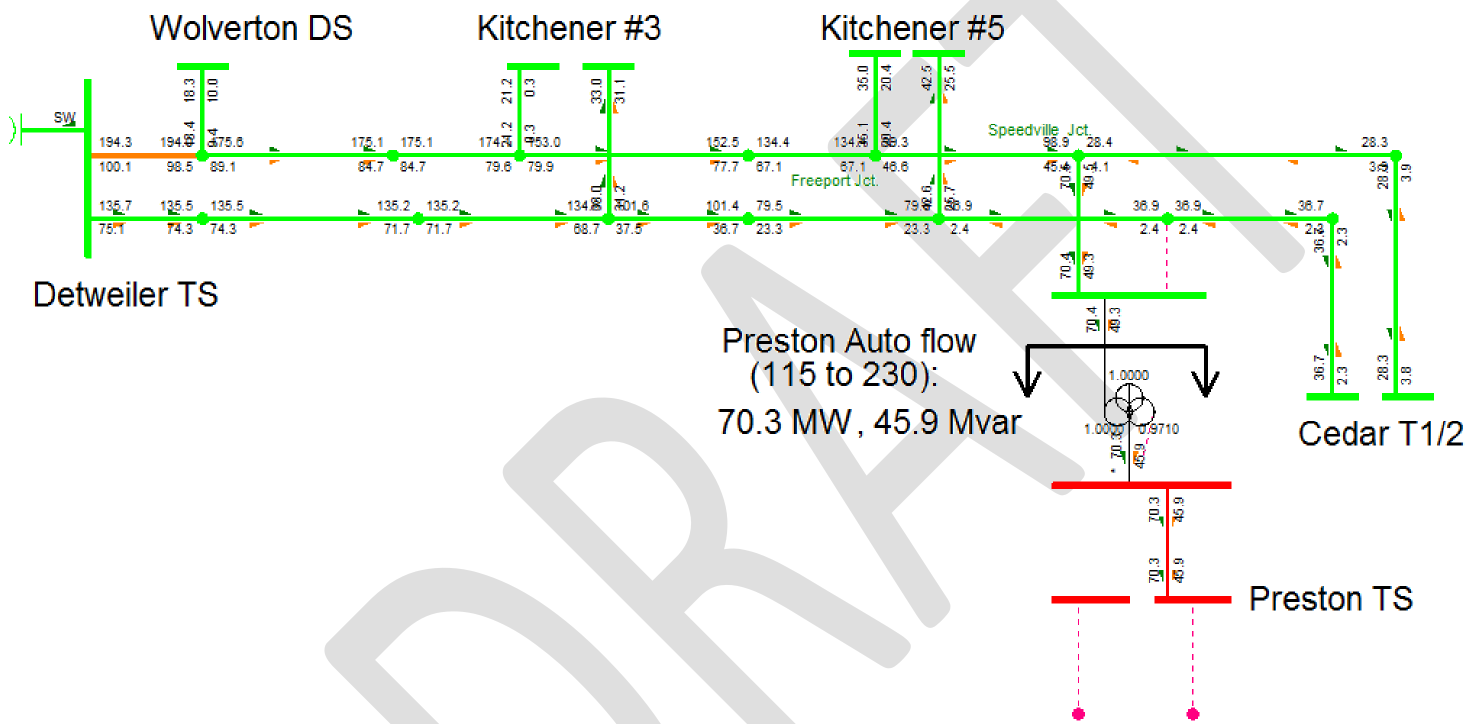


Figure F5-4: Kitchener and Cambridge 230 kV Subsystem - Post-Contingency (2012) – Loss of M20D+ M21D



This is insufficient to meet the ORTAC criteria, which specifies that all load interrupted over 250 MW must be restored within 30 minutes. Prior to the installation of the autotransformer and disconnect switches at Preston TS, power could not be restored to any customers in the area in a timely manner. Such was the case in 2003 when the supply of power to parts of the City of Cambridge, the Township of North Dumfries and the City of Kitchener, totaling over 250 MW, was interrupted for nearly four hours.

Table F5-2: Reference Demand Forecast Kitchener-Cambridge 230 kV Subsystem

Demand (MW)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Kitchener-Cambridge 230kV	507	528	547	557	577	596	616	622	639	658	678	697	716	736	756	771	791	812

As shown in Table F5-2, over the medium (2019), if the first new transformer station in the Cambridge area (Cambridge MTS #2) is connect to the Kitchener and Cambridge 230 kV subsystem, demand supplied by the M20D/M21D circuits is expected to exceed 600 MW.

F.6 Planning-Level Assessment of the Recommended Integrated Solution for the KWCG Area

South-Central Guelph 115 kV Subsystem

The near-term reinforcements will provide sufficient capacity to meet the needs in South Central Guelph until 2030, providing an incremental supply capacity of approximately 100 MW to the South Central Guelph area. This limit is based on thermal overloading of the section between Cedar and Hanlon on B6G following the loss of B5G.

Figure F6-1: South-Central Guelph 115 kV Subsystem - Pre-Contingency (2029)

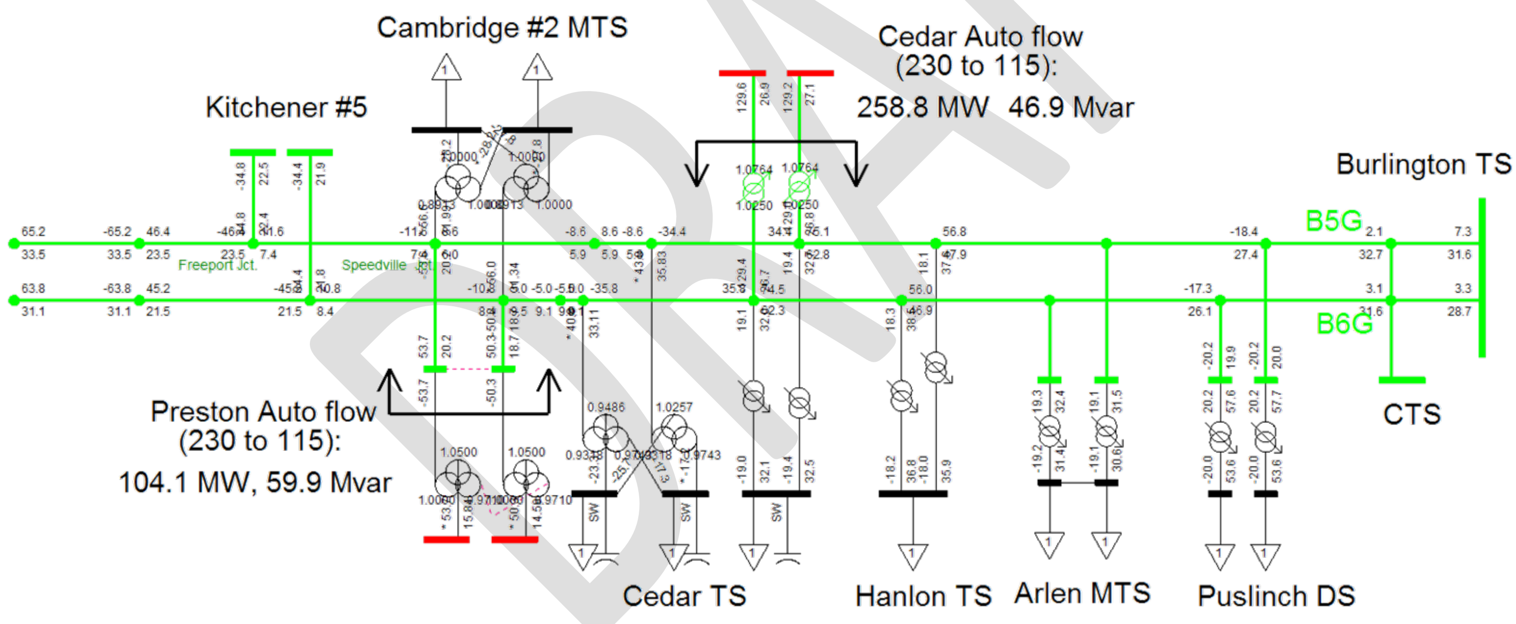
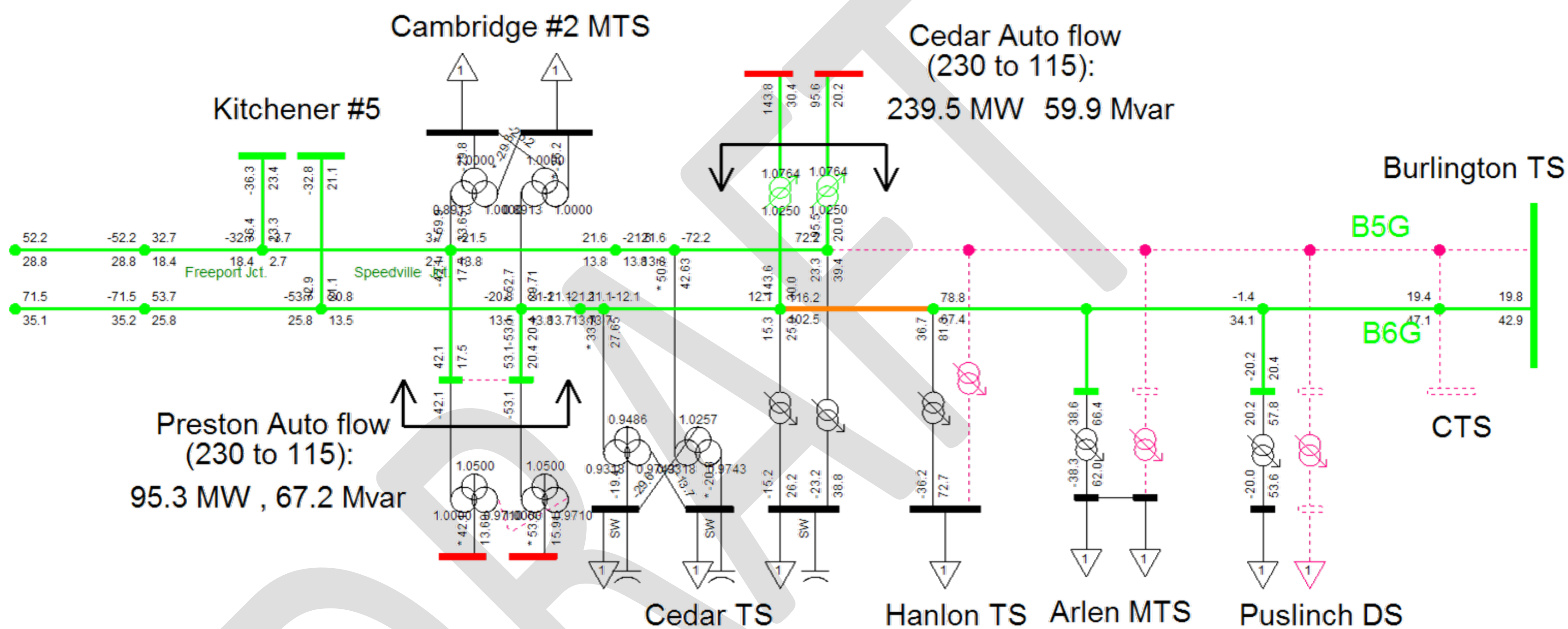


Figure F6-2: South-Central Guelph 115 kV Subsystem - Post-Contingency (2029) – Loss of B5G



Kitchener-Guelph 115 kV Subsystem

The near-term reinforcements will provide sufficient capacity to meet the needs in Kitchener-Guelph 115kV subsystem beyond the study period (Beyond 2030), providing an incremental supply capacity of at least 30 MW to the Kitchener-Guelph 115kV Subsystem. With the near-term reinforcements, no violation of the ORTAC criteria is observed on the Kitchener-Guelph 115kV subsystem within the study period

Figure F6-3: South-Central Guelph 115 kV Subsystem - Pre-Contingency (2030)

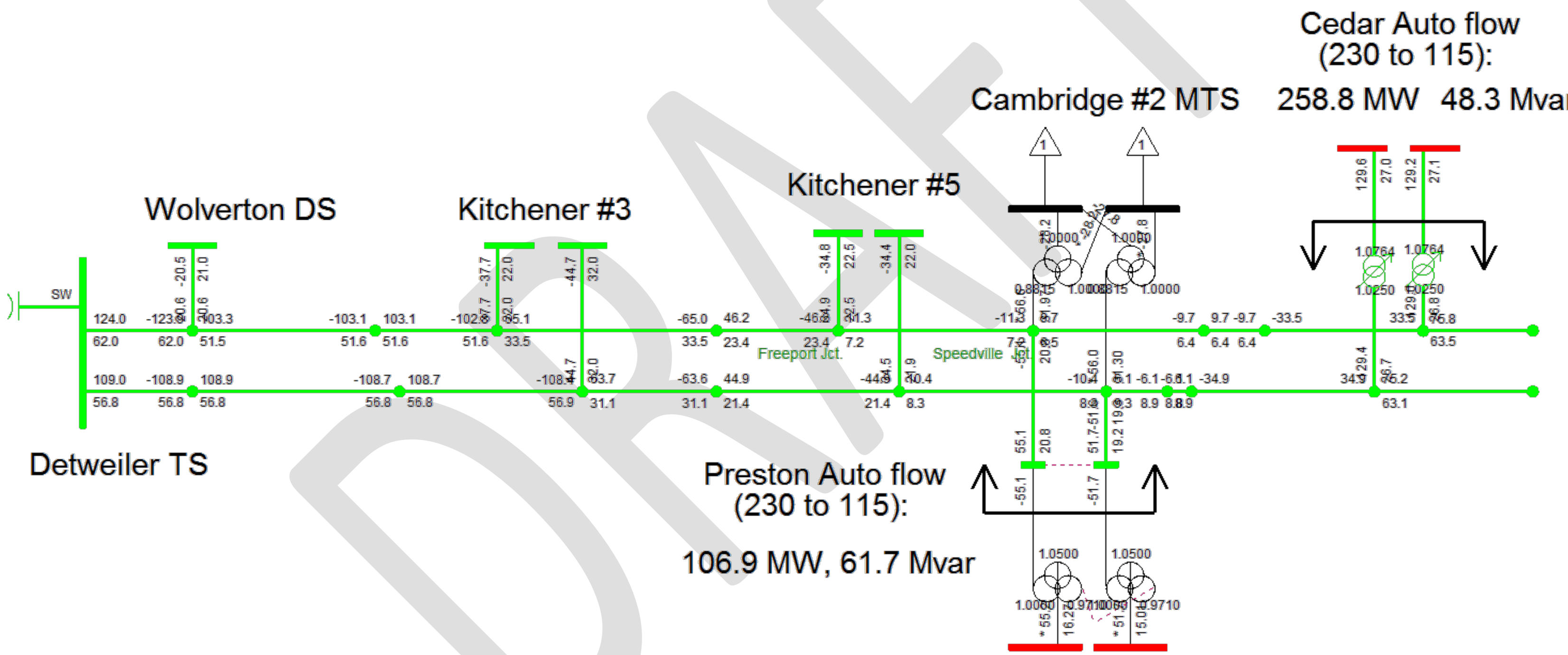
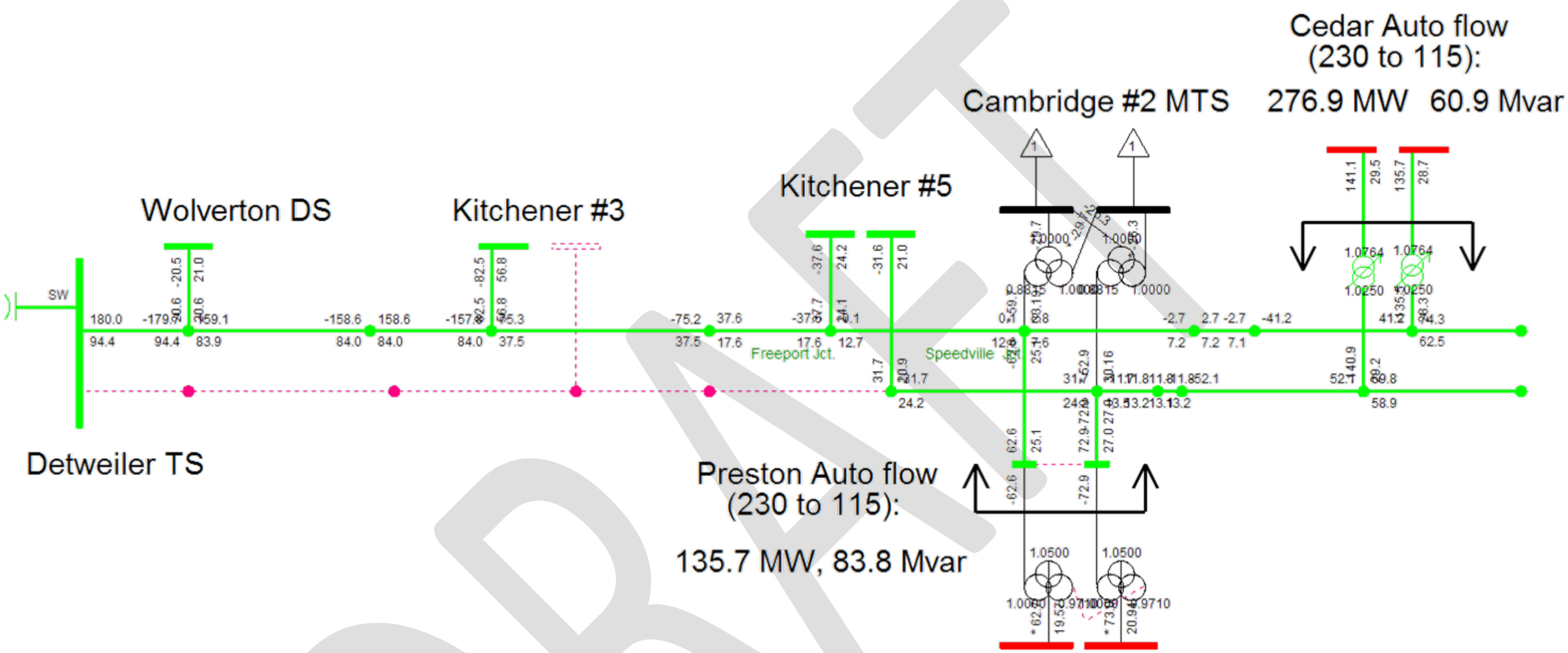


Figure F6-4: South-Central Guelph 115 kV Subsystem - Post-Contingency (2030) – Loss of D9F



Cambridge 230 kV Subsystem – Cambridge MTS 2 Connection on 115kV

The near-term reinforcements will allow Cambridge Hydro to connect the next transformer station onto the Kitchener-Guelph 115kV system and will provide sufficient capacity to meet the needs in Cambridge until 2025. In other words, the near-term reinforcement will provide an incremental supply capacity of 125 MW to the Cambridge area. Beyond 2025, additional reinforcements to the transmission may be required depending on the load growth in the area. This limit is based on thermal overloading of the section between Galt Jct and Preston Jct on M21D following the loss of M20D. At the time of this report, the detailed engineering work related to the second autotransformer at Preston TS and associated switching and reactive support is still in-progress. As such, the planned capacity available to serve load in the Cambridge 230 kV subsystem will need to be confirmed upon the completion of Hydro One's Regional Infrastructure Planning (RIP) process for the second autotransformer at Preston TS and associated switching and reactive support.

Figure F6-5: Cambridge 230 kV Subsystem with Cambridge MTS 2 Connection on Kitchener-Guelph 115kV—Pre-Contingency (2024)

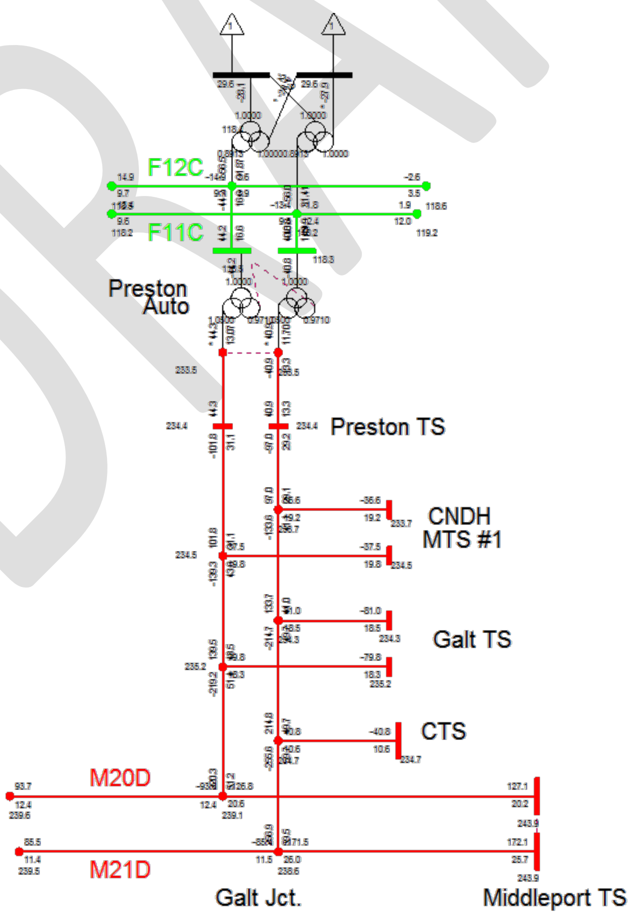
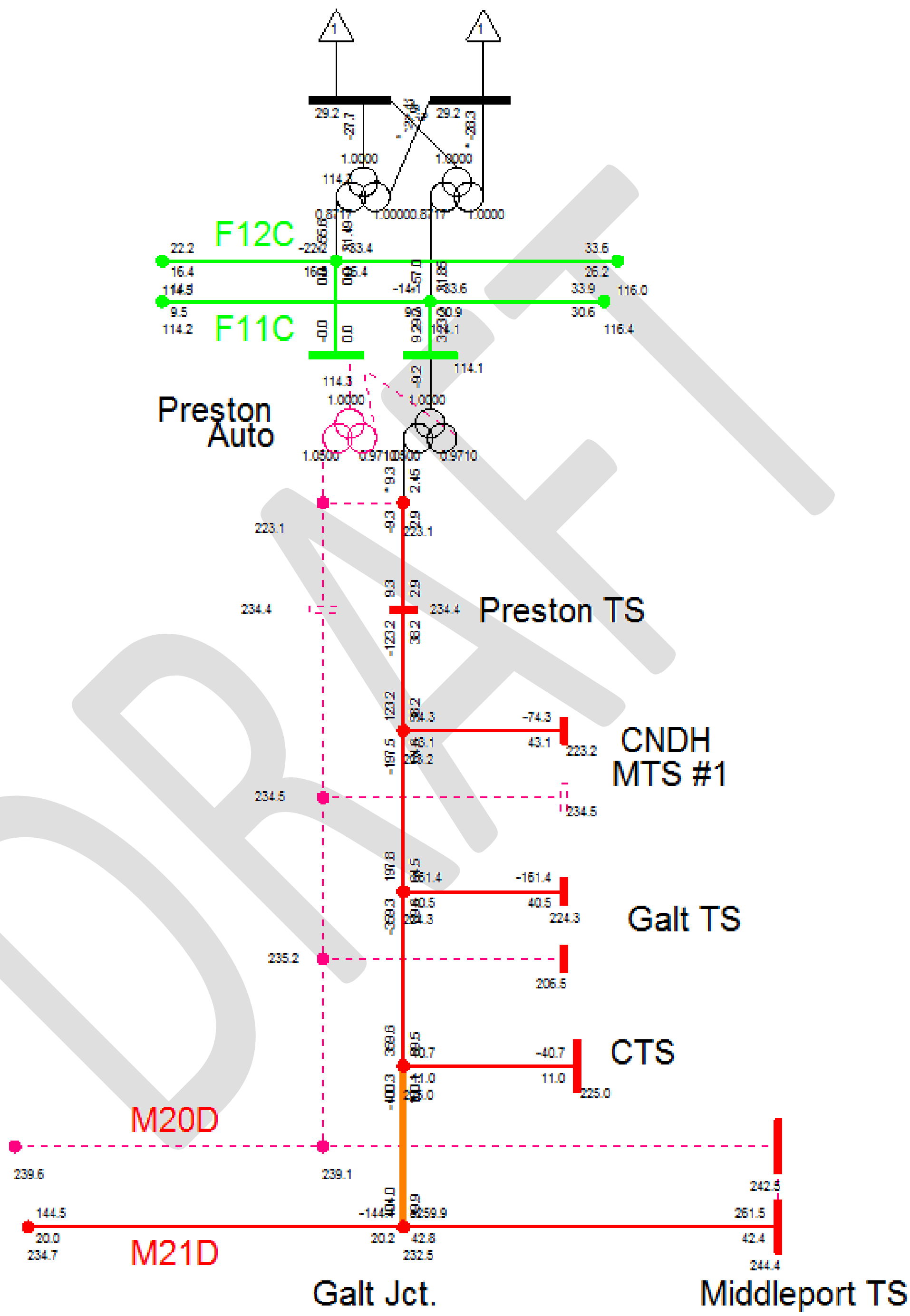


Figure F6-6: Cambridge 230 kV Subsystem with Cambridge MTS 2 Connection on Kitchener-Guelph 115kV – Post-Contingency (2024) – Loss of M20D



The near-term reinforcements will minimize the impact of potential supply interruptions on M20D/M21D. Given that Cambridge MTS #2 is connected on the Kitchener-Guelph 115kV subsystem, the loading on M20D/21D does not exceed 600 MW during the study period. With the near-term reinforcement, the system is able to restore 210 MW (2015) and 110 MW (2030) at Preston TS following the loss of M20D+ M21D [2]. Additionally, since the two preferred near-term projects enable the connection of the future Cambridge MTS #2 to the Kitchener-Guelph 115 kV system in 2018, customers supplied by the future Cambridge MTS #2 (up to 100 MW) will no longer be interrupted following the loss of the M20D/M21D circuits. At the time of this report, detailed engineering work related to the second autotransformer at Preston TS and associated switching and reactive support is still in-progress. As such, the restoration capability of the Cambridge 230 kV subsystem will need to be confirmed upon the completion of Hydro One's Regional Infrastructure Planning (RIP) process for the second autotransformer at Preston TS and associated switching and reactive support.

[2] The analysis assumes that during the 30-minute re-preparation period the voltage is expected to be restored to at least the minimum continuous voltage of 220kV and assumes that additional voltage supporting devices are installed at Preston TS as part of the near term project.

Figure F6-7: Cambridge 230 kV Subsystem with Cambridge MTS 2 Connection on Kitchener-Guelph 115kV – Post-Contingency (2015) – Loss of M20D + M21D

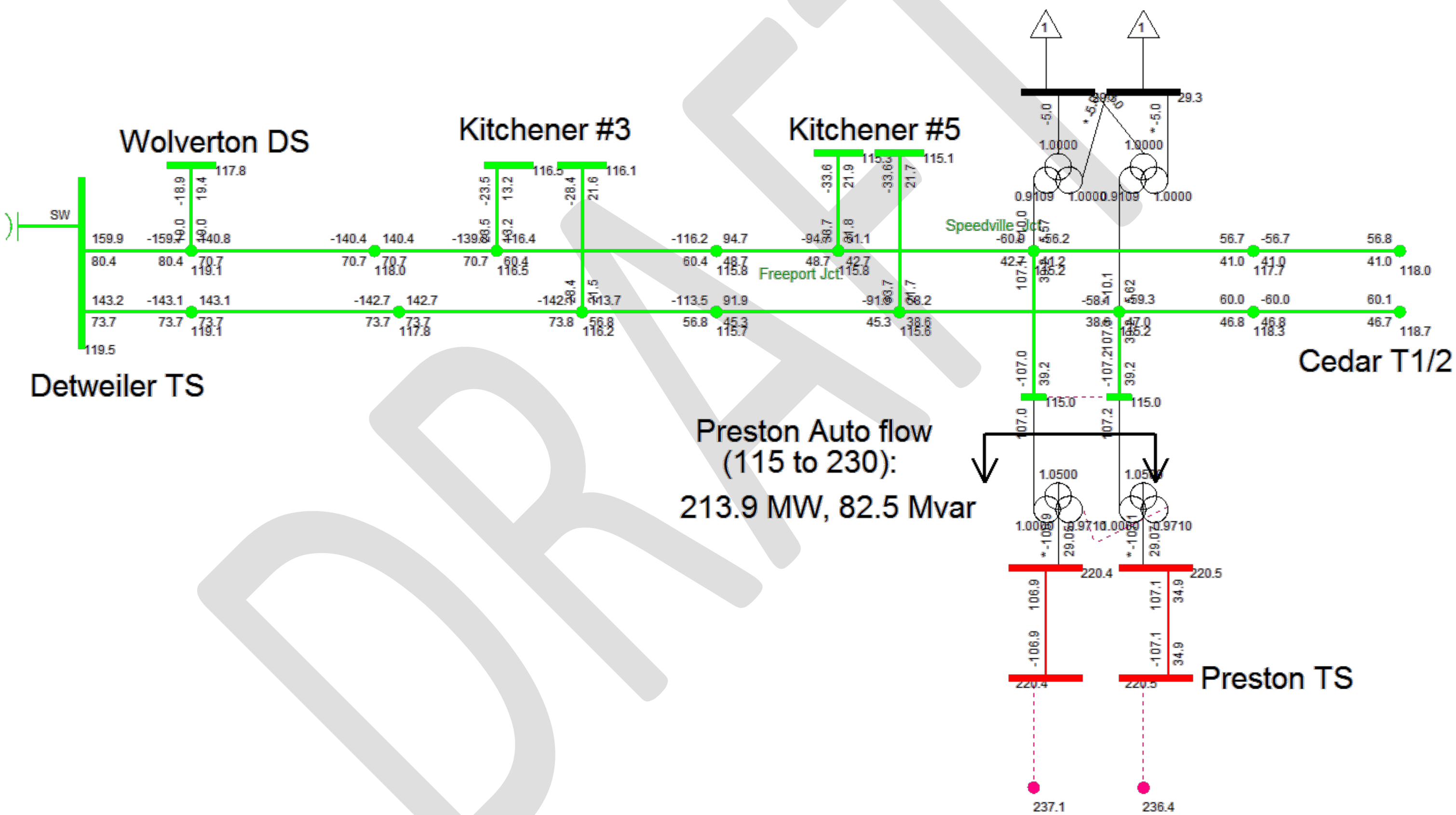


Figure F6-8: Cambridge 230 kV Subsystem with Cambridge MTS 2 Connection on Kitchener-Guelph 115kV – Post-Contingency (2030) – Loss of M20D + M21D