EXHIBIT LIST

A – ADMINISTRATIVE

Exhibit	Tab	Schedule	Contents
A	1	1	Exhibit List
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B – EVIDENCE

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C – SETTLEMENT AGREEMENT

Exhibit	Tab	Schedule	Contents
C	1	1	Settlement Agreement

D – APPENDICES

Exhibit	Tab	Schedule	Contents
D	1	1	Index of Appendices
		2	Appendix A – Minutes of Consultative Group Meeting on August 13, 2009, including Appendices
			Appendix B – Minutes of Consultative Group meeting on October 16, 2009, including Appendices
			Appendix C – Minutes of Working Group Meeting on November 20, 2009, including Appendices
			Appendix D – Minutes of Working Group Meeting on January 21, 2010, including Appendices

D – APPENDICES

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

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving a system reliability Settlement Agreement.

APPLICATION

1. The Applicant, Enbridge Gas Distribution Inc. ("Enbridge") is an Ontario corporation with its head office in the City of Toronto. It carries on the business of selling, distributing, transmitting and storing natural gas in Ontario.

2. Enbridge hereby applies to the Ontario Energy Board (the "Board"), pursuant to section 36 of the *Ontario Energy Board Act, 1998*, as amended, for an Order or Orders approving a system reliability Settlement Agreement and approving changes to rates in order to give effect to the provisions of the Settlement Agreement.

3. In its Decision and Order in Phase 2 of EB-2008-0219 released on July 14, 2009, the Board addressed a system reliability issue and it directed Enbridge to file an application with the intention of having a long term resolution of the issue to be implemented for the 2010/2011 winter season. The Board also stated its expectation that the application would include evidence of stakeholder consultation.

4. In accordance with the Board's directions in the EB-2008-0219 Decision, Enbridge proceeded with a stakeholder consultation on system reliability. Ultimately, the participants in this consultative process agreed on the provisions of a Settlement

Agreement that sets out a long term resolution of the system reliability issue (referred to in the Settlement Agreement as the Long Term Resolution). Enbridge therefore applies to the Board for approval of the system reliability Settlement Agreement and for such final, interim or other Orders as may be necessary or appropriate to give effect to the Settlement Agreement.

5. The Settlement Agreement reflects the efforts of the parties to achieve a settlement that can be implemented for the 2010/2011 winter season, as contemplated in the EB-2008-0219 Decision. Enbridge respectfully requests that the Board proceed with consideration of the Settlement Agreement as quickly as possible so that, if the Settlement Agreement is approved by the Board, the Long Term Resolution can be implemented for the 2010/2011 winter season. Enbridge anticipates that approval granted prior to September 1, 2010 would allow implementation for the upcoming winter.

6. All of the intervenors in the EB-2008-0219 proceeding were given an opportunity to participate in the consultative process and there were over 20 members of the consultative group, representing a wide range of different interests. Each stakeholder has been consulted with respect to its position on the provisions of the Settlement Agreement and no stakeholder has indicated that it is opposed to the Agreement. Given the extent of stakeholder involvement in the consultation process, and because this application arises directly from consideration of system reliability matters in Enbridge's 2009 rate adjustment proceeding (EB-2008-0219), Enbridge proposes that the intervenors in this application be deemed to be the intervenors in EB-2008-0219 and in Enbridge's subsequent 2010 rate adjustment proceeding, EB-2009-0172.

7. Further, Enbridge requests that the Board consider a process for consideration of the Settlement Agreement that does not include interrogatories or a technical

conference. More specifically, in the event that no parties seek to comment on the Settlement Agreement other than those which have already given their positions on the Agreement, Enbridge respectfully proposes that the primary elements of the process for consideration of the Agreement be the presentation of the Agreement to the Board and an opportunity for the Board's questions, if any, to be addressed.

8. Enbridge therefore applies to the Board pursuant to the provisions of the Act and the Board's *Rules of Practice and Procedure* for such final, interim or other Orders and directions as may be appropriate in relation to the proper conduct of this proceeding, given that the application arises from the EB-2008-0219 Decision and the successful consultative process that followed the Decision.

9. Enbridge requests that a copy of every document filed with the Board in this proceeding be served on the Applicant and the Applicant's counsel, as follows:

The Applicant:

Mr. Norm Ryckman
Director, Regulatory Affairs
Enbridge Gas Distribution Inc.

Address for personal service:	500 Consumers Road Willowdale, Ontario M2J 1P8
Mailing address:	P. O. Box 650 Scarborough, Ontario M1K 5E3
Telephone:	416-753-6280
Fax:	416-495-6072
Email:	EGDRegulatoryProceedings@enbridge.com

The Applicant's counsel:

Mr. Fred D. Cass
Aird & Berlis LLP

Address for personal service and mailing address	Brookfield Place, P.O. Box 754 Suite 1800, 181 Bay Street Toronto, Ontario M5J 2T9
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Email:	fcass@airdberlis.com

DATED July 15, 2010, at Toronto, Ontario.

ENBRIDGE GAS DISTRIBUTION INC.

Per: Robert Bourke

OVERVIEW AND SUMMARY OF APPLICATION

1. In this proceeding, Enbridge Gas Distribution Inc. (Enbridge) is applying to the Ontario Energy Board (the "Board") pursuant to section 36 of the *Ontario Energy Board Act, 1998*, as amended, for an Order or Orders approving a system reliability Settlement Proposal and approving changes to rates in order to give effect to the provisions of the Settlement Agreement.

2. In its Decision and Order in Phase 2 of EB-2008-0219 released on July 14, 2009, the Board addressed a system reliability issue and it directed Enbridge to file an application with the intention of having a long term resolution of the issue to be implemented for the 2010/2011 winter season. The Board also stated its expectation that the application would include evidence of stakeholder consultation.

3. In accordance with the Board's directions in the EB-2008-0219 Decision, Enbridge proceeded with a stakeholder consultation on system reliability. Ultimately, the consultation process resulted in a Settlement Agreement setting out the terms of a long term resolution of the system reliability issue. The terms of the Settlement Agreement provide for a multi-faceted approach that works together as a package and is based on the following elements:

- Assignment of 50,000 GJ/day of short haul transportation capacity and replacement of that capacity with Short Term Firm Transportation ("STFT")
- Replacement of peaking supplies. Enbridge will reduce the amount of peaking supplies in its gas supply portfolio by 200,000 GJ/day and will replace those supplies with STFT
- Changes to the terms of service for large volume customers in order to enhance the effectiveness and reliability of gas supply planning

- Revisions to the curtailment rules and practices in order to increase the effectiveness and reliability of curtailment
- Turnback provisions will be changed to place restrictions and administrative requirements for the turnback of firm transportation capacity

The specific details of the elements illustrated above are included in the attached Settlement Agreement.

4. The consultative process that was utilized occurred over a number of months beginning in the summer of 2009 and concluded with settlement discussion in early summer, 2010.

5. The first consultative meeting was held on August 13, 2009. At this meeting, the participants discussed the consultation process and timetable. In addition to a representative from the Board and representatives from Enbridge, the participants in the meeting were as follows:

Access Gas Services Inc. (Access)
Aegent Energy Advisors Inc. (Aegent)
Association of Power Producers of Ontario (APPrO)
Building Owners and Managers Association of Greater Toronto (BOMA)
BP Canada (BP)
Consumers Council of Canada (CCC)
Canadian Manufacturers & Exporters (CME)
Direct Energy Marketing Limited (Direct)
E2 Energy Inc. (E2)
ECNG Energy L.P. (ECNG)
Energy Probe Research Foundation (Energy Probe)
Industrial Gas Users Association (IGUA)
Jason Stacey
Ontario Association of Physical Plant Administrators (OAPPA)
Ontario Energy Savings Corporation (now Just Energy)
Shell Energy North American (Canada) Inc. (Shell Canada)
Superior Energy Management Gas L.P. (Superior)
TransAlta Cogeneration Limited Partnership (TransAlta)
TransCanada Pipelines Limited (TCPL)

6. The second consultative meeting took place on October 16, 2009. There were two additional participants in this meeting which were not present at the August 13th meeting, namely, Union Gas Limited (Union) and School Energy Coalition (SEC). The consensus of the participants in the consultative was that a smaller Working Group should be created to continue discussions about a long term resolution of the system reliability issue and that the Working Group should report back to the broader group of participants. CCC indicated its willingness to contact the Vulnerable Energy Consumers Coalition (VECC) about participation in the Working Group and the following were chosen as members of the Working Group:

Aegent
CCC/VECC
CME
Direct
Enbridge
IGUA
Shell
TCPL
Union

7. The Working Group held a number of meetings and its discussions advanced to the point where the members of the Working Group agreed that it would be of value to hold a settlement meeting to consider whether the Working Group could agree on a long term resolution of the system reliability issue. This settlement meeting began in the afternoon of May 17, 2010 and continued on May 18th. By the conclusion of the settlement meeting on May 18th, the Working Group had agreed on the components of a proposal for the long term resolution of the system reliability issue.

8. The proposed settlement was discussed with the broader Consultative Group on June 15, 2010 and again on June 23rd. The outcome of the process was a Settlement Agreement that sets out a Long Term Resolution of the system reliability issue and is found at Exhibit C, Tab 1, Schedule 1.

9. Minutes were kept of meetings of the Working Group and of the broader consultative group that did not involve confidential settlement discussions. Settlement discussions proceeded on a confidential basis and no minutes were kept of meetings at which settlement was discussed. In addition to the discussions that occurred at meetings of the Working Group and the broader Consultative Group, all stakeholders participated in the exchange of certain information outside of the meetings. The record of the consultative process is included in the Appendices that accompany this evidence, as set out in Table 1, below.

TABLE 1

Consultative Meeting Notes	August 13, 2009	Appendix	A
	October 16, 2009		B
	November 20, 2009		C
	January 21, 2010		D
	February 25, 2010		E
	April 8, 2010		F
	April 30, 2010		G
	May 17, 2010		H
Miscellaneous Information Requests	Various Dates	Exhibit	D-2-1
Settlement Discussions	May & June, 2010		N/A

10. The Long Term Resolution of the system reliability issue was reached after an inclusive, thorough and comprehensive consultative process. The rationale for the Long Term Resolution is set out in Appendix A to the Settlement Agreement and is supported by the record of the consultative process, as summarized in Table 1. Appendix A also addresses the impacts of the Long Term Resolution. The other options identified and considered during the consultative process, including a “vertical slice” methodology, can be seen in the meeting notes, such as the minutes of the Consultative Group meeting on October 16, 2009 (at pages 4 and 5 and Appendix D).

SETTLEMENT AGREEMENT

ENBRIDGE GAS DISTRIBUTION INC.

SYSTEM RELIABILITY

JULY 15, 2010

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I. BACKGROUND AND CONTEXT

In its EB-2008-0219 Phase 2 Decision and Order issued on July 14, 2009, the Ontario Energy Board (the "Board") addressed a "system reliability issue"[1] raised by Enbridge Gas Distribution Inc. ("Enbridge"). The Decision set out an interim resolution of the issue that would be in place for the upcoming winter of 2009/2010 and that would remain in place until a long term resolution has been approved by the Board.

In the Decision, the Board went on to state its view that a long term resolution of the system reliability issue is needed. The Board directed Enbridge to bring forward an application with the intention of having the long term resolution implemented for the winter of 2010/2011. The Board also stated its expectation that, for the hearing of the long term resolution, evidence of stakeholder consultation would be brought forward. In order to fulfill the Board's expectation, Enbridge initiated a consultation process with stakeholders to consider a long term solution to the system reliability issue.

The initial meeting of the consultative was held on August 13, 2009. The consensus of the participants in this consultative meeting was that a smaller group (the "Working Group") should be created to continue discussions about a long term resolution of the system reliability issue and that the Working Group should report back to the broader group of participants (the "Consultative Group"). At a second meeting of the consultative on October 16, 2009, the following were chosen as members of the Working Group:

Canadian Manufacturers & Exporters (CME)
Industrial Gas Users Association (IGUA)
Union Gas Limited (Union)
TransCanada PipeLines Limited (TCPL)
Shell Energy North America (Canada) Inc.
Aegent Energy Advisors Inc. (Aegent)
Consumers Council of Canada/Vulnerable Energy Consumers Coalition (CCC/VECC)
Direct Energy Marketing Limited (Direct)
Enbridge.

[1] In this Background and Context section of the Settlement Agreement, the words "system reliability issue" are quoted from the EB-2008-0219 Phase 2 Decision and Order.

The Working Group met on November 20, 2009, January 21, 2010, February 25, 2010, April 8, 2010 and April 30, 2010 to discuss the system reliability issue. Discussions on the issue advanced to the point where the members of the Working Group agreed that it would be of value to hold a settlement meeting to consider whether the Working Group could agree on a long term resolution. A further consultative meeting of the Working Group was held during the morning of May 17, 2010. The settlement meeting of the Working Group began in the afternoon of May 17th and continued on May 18th.

By the conclusion of the settlement meeting on May 18th, the Working Group had agreed on the components of a proposal for a long term resolution to the system reliability issue (referred to in the following provisions of this agreement as the "Long Term Resolution") to be presented to the Consultative Group. The Working Group reported back to the Consultative Group with regard to this proposal on June 15, 2010 and a further meeting of the Consultative Group took place on June 23, 2010. In addition to the members of the Working Group, the participants in the Consultative Group are as follows:

Access Gas Services Inc. (Access)
Association of Power Producers of Ontario (APPrO)
Building Owners and Managers Association of Greater Toronto (BOMA)
BP Canada (BP)
E2 Energy Inc. (E2)
ECNG Energy L.P. (ECNG)
Energy Probe Research Foundation (Energy Probe)
Federation of Rental-Housing Providers of Ontario (FRPO)[2]
Jason F. Stacey
Just Energy Ontario L.P. (Just Energy)
Ontario Association of Physical Plant Administrators (OAPPA)
Superior Energy Management Gas L.P. (Superior)

[2] By letter dated May 27, 2010, the Board granted late intervention status to FRPO.

II. SETTLEMENT PREAMBLE

As a result of the consultative process, the Consultative Group has reached agreement on all aspects of the Long Term Resolution of the system reliability issue. Board Staff has attended meetings during the consultative process, but it is not a party to this Settlement Agreement. Certain members of the Consultative Group are of the view that Enbridge has been unable to establish to their satisfaction that it does, in fact, have a system reliability problem by reason of the level of firm upstream transportation arrangements to its franchise areas. Nevertheless, these parties recognize that the Board has acknowledged Enbridge's system reliability concern, and accept that the Long Term Resolution addresses Enbridge's concerns, and should address any concerns of the Board, in a manner that is minimally intrusive of the market and that minimizes ratepayer costs.

The facts supporting this Settlement Agreement are found in the record of information exchanged and discussed at, or in conjunction with, the meetings of the Consultative Group and of the Working Group. The parties are of the view not only that this record supports the Settlement Agreement but also that the quality and detail of the record, together with the corresponding rationale set out in Appendix A to this agreement, will allow the Board to accept the Long Term Resolution.

The parties to the settlement all agree that this Settlement Agreement is a package: the individual aspects of this agreement are inextricably linked to one another and none of the parts of this settlement are severable. As such, there is no agreement among the parties to settle any aspect of the issues addressed in this Settlement Agreement in isolation from the balance of the issues addressed herein. The parties agree, therefore, that in the event that the Board does not accept this Settlement Agreement in its entirety, then there is no agreement. If the Board does not accept the Settlement Agreement, Enbridge will file an application seeking approval of a proposal for a long term resolution of the system reliability issue and the parties to this Settlement Agreement will be at liberty to take such positions as they see fit in respect of that application. More specifically, the efforts of the parties to reach a settlement of the system reliability issue will not in any way prejudice the positions that they may take in the event that the Settlement Agreement is rejected by the Board.

Further, the agreement by the parties on the Long Term Resolution in this case will not in any way prejudice the positions that they may take in future proceedings, particularly if issues relating to Enbridge's system reliability are reconsidered.

While the consultative process under which this settlement was reached was not formally initiated by the Board under Rule 31 of the *Ontario Energy Board Rules of Practice and Procedure*, the parties agree that it is appropriate that Rules 31.09, 31.10 and 32 apply to the settlement process and this Settlement Agreement.

Enbridge is not seeking recovery of any administrative, system, and internal process change costs that may be over and above what is provided for in the existing IR framework unless expressly set out in this Agreement.

III. TERMS OF SETTLEMENT

The Long Term Resolution of the system reliability issue agreed to by the Consultative Group consists of the following terms.

1. Assignment of Short Haul Capacity

Enbridge has contracted with TCPL for short haul firm transportation capacity from Dawn, Ontario to TCPL's Enbridge Central Delivery Area ("CDA"). Subject to the Annual Review described below, Enbridge will assign[3] 50,000 GJ/day of this short haul firm transportation capacity to agents for mass market customers[4] that meet the definition of "Agent" below and Enbridge will replace the assigned capacity with an equivalent volume of TCPL Short Term Firm Transportation ("STFT") capacity from Empress, Alberta that it will secure annually, or if economic, equivalent firm transportation.[5] The cost consequences of this component of the Long Term Resolution will be recovered from sales and Western-T service customers allocated by volume, pursuant to the Board-approved cost allocation and rate design methodology.

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[3] Each such assignment of short haul firm transportation capacity will be a "temporary assignment", as that term is used by TCPL.

[4] Mass market customers are those in the general service rate classes, which currently are Rate 1, Rate 6 and Rate 9.

[5] Should Enbridge contract for any such equivalent firm transportation as part of the Long Term Resolution, it will include a note in its QRAM filing to that effect.

The customer bill impacts of this component of the Long Term Resolution are set out at page 11 of Appendix A.

For the purpose of the temporary assignment of short haul firm transportation capacity, an agent is defined to be an agent for mass market customers that has signed a Master Services Agreement with Enbridge and that more particularly meets all of the following criteria:

(i) the agent has created a pool of non-affiliated customers, such that the agent does not own a controlling interest (50% or more) of all of the entities served at the gas delivery locations included within the pool;
(ii) the agent has on file for presentment executed Agency Appointment Letters for all customers included in the pool; and
(iii) the agent has a total mass market Ontario T-service ("OTS") Mean Daily Volume ("MDV") delivery obligation of 1,500 GJ/day or more.

An agent within the meaning of this definition will be referred to as an "Agent' in the following provisions of this Settlement Agreement.

The temporary assignment of short haul firm transportation capacity to an Agent by Enbridge will be mandatory and will be made on the following terms:

(i) each assignment will be for a one year period (the "Assignment Year") and will commence on November 1st, starting with November 1, 2010;
(ii) the amount of transportation capacity assigned to each Agent for each Assignment Year will be determined using an allocation methodology (the "Allocation Methodology") on a date in the immediately preceding year (the "Allocation Date") that accommodates the procurement of STFT by Enbridge when first offered by TCPL for the winter season of the Assignment Year;
(iii) the steps in the Allocation Methodology are as follows:

(a) for each Agent, calculate the total of all mass market account MDV's within the Agent's OTS pools (excluding any large volume account MDVs);

(b) calculate the total of all mass market OTS MDV's (excluding any large volume account MDVs) for all Agents ("Total Mass Market OTS Volumes"); and

(c) for each Agent, divide the total derived from step (a) by the Total Mass Market OTS Volumes derived from step (b) and multiply this amount by 50,000 GJ/day, or such other amount as is determined under the Annual Review described below, to arrive at the amount of short haul firm transportation capacity that will be assigned to the Agent.

(iv) prior to the end of the term of each group of one-year assignments, the transportation capacity to be assigned to each Agent for the next Assignment Year will be determined on the Allocation Date using the Allocation Methodology; and

(v) the total amount of short haul firm transportation capacity to be assigned to Agents by Enbridge will be reviewed annually as of the Allocation Date (the "Annual Review") and the capacity to be assigned for each Assignment Year will be determined in the following manner:

(a) the total amount of short haul firm transportation capacity to be assigned to Agents for the Assignment Year beginning November 1, 2010 is 50,000 GJ/day;

(b) as of each subsequent Allocation Date, the ratio of 50,000 GJ/day to Total Mass Market OTS Volumes will be determined;

(c) if the ratio calculated under (b), above, is such that 50,000 GJ/day represents no more than 40% of Total Mass Market OTS Volumes, then the total amount of short haul firm transportation capacity to be allocated to Agents for the following Assignment Year will be 50,000 GJ/day;

(d) if the ratio calculated under (b) above, is such that 50,000 GJ/day represents more than 40% of Total Mass Market OTS Volumes, then the total amount of short haul firm transportation capacity to be allocated to Agents for the following Assignment Year will be adjusted (that is, decreased below 50,000 GJ/day) to a level that represents 40% of Total Mass Market OTS Volumes; and

(e) in no event will there be an adjustment resulting from the Annual Review under this provision of the Settlement Agreement that increases the total capacity of short haul firm transportation to be assigned above 50,000 GJ/day.

The 50,000 GJ/day of STFT capacity contracted for annually by Enbridge will be for the months of November, December, January, February and March and this STFT service, or the equivalent firm transportation capacity referred to above, will be acquired throughout the term of the Long Term Resolution, unless otherwise agreed to by the parties or ordered by the Board.

2. Replacement of Peaking Supplies

As part of its gas supply portfolio, Enbridge contracts for peaking supplies that are utilized in peak and near-peak conditions. Peaking supplies are pre-contracted arrangements for delivered supply to Enbridge's franchise area that it can call upon, typically on at least ten days during the winter season.

Enbridge will reduce the amount of peaking supplies held under contract as part of its gas supply portfolio by 200,000 GJ/day and it will replace these peaking supplies with an equivalent volume (200,000 GJ/day) of TCPL STFT service from Empress that it will secure annually, or, if economic, equivalent firm transportation.[6] The 200,000 GJ/day of STFT service contracted for annually by Enbridge will be for a period of three months (not limited to calendar months) over the winter throughout the term of the Long Term Resolution, unless otherwise agreed to by the parties or ordered by the Board. The STFT service will be utilized in lieu of an equivalent amount of peaking supplies in peak

[6] Should Enbridge contract for any such equivalent firm transportation as part of the Long Term Resolution, it will include a note in its QRAM filing to that effect.

and near-peak conditions. In addition, STFT service will be used to displace other winter purchases, when it is economic and operationally appropriate to do so. The cost consequences of this component of the Long Term Resolution will be recovered from all customers using the deliverability allocator (that is, rate class demand in excess of its average winter demand) under the Board approved cost allocation and rate design methodology and the benefits associated with displacement of other winter purchases will be allocated by volume to sales and Western-T service customers. The customer bill impacts of this component of the Long Term Resolution are set out at page 14 of Appendix A.

3. Terms of Service for Large Volume Customers

The terms of service for Large Volume customers will be changed in order to enhance the effectiveness and reliability of gas supply planning. These changes will require revisions to Enbridge's Rate Handbook, as set out in Appendix B to this Settlement Agreement. The changes to the terms of service are as follows:

(i) Currently, the Rate Handbook is silent with regard to the notice that must be given by large volume customers to Enbridge in order to suspend deliveries.[1] The Rate Handbook will be revised to state that a large volume customer must deliver its MDV to Enbridge, but that the customer may suspend delivery, fully or partially, of its MDV without authorization from Enbridge, provided that the customer gives notice to Enbridge of the suspension, and of the customer's intent to decrease consumption in tandem with the suspension, at least two full business days before the suspension will commence. Notices of suspension must be given in accordance with Enbridge's Business Transaction Rules.

(ii) Failure to provide proper notice will result in Unauthorized Supply Overrun Gas calculated as the difference between Daily Delivered Volume and the Mean Daily Volume.

(iii) Currently, the contracts for service to large volume customers contain provisions regarding Enbridge's rights in the event of non-compliance by a customer, but these provisions require additional clarity, particularly with respect to Enbridge's right to suspend gas distribution services. The provisions of these contracts will be revised to state that Enbridge may suspend service to a customer taking Unauthorized Supply Overrun Gas or to a customer that has failed to deliver its MDV to Enbridge and that has not given notice that meets the requirements set out in paragraph 3(i), above. Enbridge will amend the wording of its Large Volume Distribution Contract to put into effect this element of the Settlement Agreement, including changes to Part 4.1, Unauthorized Overrun Gas, and Part 6.2, Suspension of Company's Obligations.

[1] Such suspension is distinct from requests by customers to suspend deliveries for purposes of balancing their banked gas account(s) ("BGA"). These BGA balancing suspensions are pre-authorized by Enbridge through EnTRAC. Enbridge is changing its EnTRAC Business Transaction Rules for pre-authorized suspension and make-up requests to reduce the minimum notice period from five business days to two business days. Two business days is the minimum notice that the Company can accommodate based on current operational and system constraints.

4. Curtailment

Enbridge relies on curtailment of interruptible customers in order to meet peak demands on its system. As part of the Long Term Resolution, steps will be taken to increase the effectiveness and reliability of curtailment, which in turn will increase the effectiveness and reliability of Enbridge's gas supply planning. These steps will require revisions to Enbridge's Rate Handbook, as set out in Appendix B to this Settlement Agreement. The steps to increase the effectiveness of curtailment are as follows:

(i) Enbridge's Rate Handbook provides, in respect of interruptible service under Rate 145, that service shall be subject to curtailment upon the Company issuing a notice not less than 72 hours prior to the time at which curtailment is to commence, and that the customer may, by contract, agree to a shorter notice period. The curtailment credit rates are based on a 16 hour notice period and a 72 hour notice period. Curtailment of service that requires a notice period of 72 hours is no longer an effective part of Enbridge's gas supply planning. Interruptible service on 72 hours notice under Rate 145 will therefore be eliminated. This will require changes to the Rate Handbook that include changing the reference to 72 hours notice under "Character of Service" to 16 hours and removing the curtailment credit for interruptible service with a 72 hour notice period.

(ii) The provisions of the Rate Handbook currently provide that a customer that has taken Unauthorized Supply Overrun Gas is deemed to have purchased such volume of gas at 150% of the average price on each day on which an overrun occurred for the calendar month as published by the Gas Daily for the Niagara and Iroquois export points for the CDA and the EDA delivery areas respectively. The current provisions of the Rate Handbook also state that the third instance of an interruptible customer taking Unauthorized Overrun Gas may result in the customer forfeiting the right to be served under the interruptible rate schedule. The effectiveness of curtailment will be improved by establishing more appropriate penalties that will apply in the event that a customer fails to comply with a curtailment notice. The wording of the Rate Handbook will be changed to state that, when a customer takes Unauthorized Supply Overrun Gas, the customer shall purchase gas at 150% of the highest price on each day on which an overrun occurred (rather than 150% of the average price). The wording will also be changed to state that, when a customer takes a material volume of Unauthorized Supply Overrun Gas during a period of ordered curtailment, the customer will forfeit its curtailment credits for the respective winter season of December through March inclusive. Finally, the wording which now states that the third instance in a contract year when a customer takes Unauthorized Overrun Gas may result in the customer forfeiting the right to be served under an interruptible rate will be changed to say that any instance when a customer takes a material volume of Unauthorized Supply Overrun Gas during a period of ordered curtailment may result in the customer forfeiting the right to receive interruptible service.

(iii) The Rate Handbook does not currently contain an explicit requirement that customers receiving service under an interruptible rate have a demonstrable ability to curtail their consumption. The effectiveness of curtailment will be improved by ensuring that customers who receive service under an interruptible rate do indeed have the ability to curtail upon receipt of the prescribed notice from Enbridge, rather than relying solely on Curtailment Delivered Supply.[2] This will be accomplished by changes to the wording in the Rate Handbook for Rates 145 and 170 to state that service under these Rates is available only to customers who have a demonstrated capability to cease or reduce operations, or to utilize a backup fuel, in order to curtail their consumption of natural gas in accordance with a curtailment notice.

Enbridge will report on curtailment compliance in its application filed with the Board for 2013 rates.

5. Turnback

Rider A, Transportation Service Rider, in the Rate Handbook contains provisions with respect to TCPL Firm Transportation (FT) capacity turnback. These provisions are applicable to Ontario T-Service customers who have been or will be assigned TCPL capacity by Enbridge. Rider A states that Enbridge will accommodate TCPL capacity turnback to the extent that it is allowed to turnback FT capacity to TCPL and in a manner that minimizes stranded and other transitional costs. Rider A also states that

[2] Curtailment Delivered Supply ("CDS") refers to additional supply that a customer plans to deliver to the Enbridge franchise area in order to be able to continue consuming in the face of a request for curtailment

Enbridge is committed to maintaining the integrity of its distribution system and the sanctity of all contracts. Rider A currently is silent with respect to turnback for Western-T Service customers, but in the past Enbridge has accommodated a level of turnback for these customers.

These provisions will be changed to place restrictions on the turnback of FT capacity, in view of Enbridge's concern about firm transportation arrangements to its franchise areas and because FT capacity turnback affects Enbridge's operational ability to meet winter demand using TCPL's Storage and Transportation Service (STS), as such STS entitlement is available based on contracted long haul FT capacity. The turnback changes will require revisions to Enbridge's Rate Handbook, as set out in Appendix B to this Settlement Agreement. The changes to the turnback provisions of Rider A are as follows:

(i) The "Applicability" provision will be changed to include both Ontario T-service customers and Western T-service customers;

(ii) Paragraphs 1, 3 to 7 inclusive and 9 of the "Terms and Conditions of Service" will be removed and replaced with the new paragraph 1 that follows below. The remaining paragraphs of the Terms and Conditions of Service will be re-numbered accordingly. The new paragraph 1 of the Terms and Conditions of Service is:

1. The Company will accommodate TCPL FT capacity turnback requests from customers, but only if it can do so in accordance with the following considerations:

i. The TCPL FT capacity to be turned back must be replaced with alternative, contracted firm transportation (primary capacity or assignment) of equivalent quality to the TCPL FT capacity;

ii The amount of TCPL turnback capacity that Enbridge otherwise may accommodate may be reduced to address the impact of stranded costs, other transitional costs or incremental gas costs arising from any turnback request that reduces flexibility to meet winter demand using TCPL STS; and iii Enbridge will act in a manner that maintains the integrity and reliability of the gas distribution system and that respects the sanctity of contracts.

The new paragraph 2 is "Request for TCPL Turnback must be made in writing to the attention of Enbridge's Direct Purchase Group". This paragraph has been restated to reflect the new administrative process resulting from the Turnback changes listed above in Section V.

These new provisions of Rider A will not apply to any existing turnback arrangements or pending turnback requests that have been accepted by Enbridge prior to the final adoption of the new turnback wording in the Rate Handbook.

IV. MATERIAL CHANGE IN CIRCUMSTANCES

In the event of a change in circumstances that affects security of supply to Enbridge's franchise area and/or the Long Term Resolution in any material way ("Material Change"), Enbridge will review the implications of the change and, within a reasonable period of time after the change has become known, will report to the parties to this Settlement Agreement regarding the implications of the change on system reliability and/or the Long Term Resolution. For this purpose, a Material Change will include, but not be limited to, the following:

~ construction of new facilities that increase the availability of short haul firm transportation service to Enbridge's franchise area

~ a material change in the availability of TCPL discretionary services

~ the conclusion from any future Board process that addresses matters relevant to Enbridge's system reliability.

While Enbridge will be responsible to monitor market or regulatory developments for a Material Change, nothing in this agreement precludes any party from bringing its concerns regarding a Material Change to the Board for consideration of any impact on the Long Term Resolution.

V. AGREEMENT OF THE PARTIES

TCPL and Union do not oppose, but take no position on, the settlement set out in this Settlement Agreement. VECC does not oppose, but takes no position on, part 1 of the Terms of Settlement (Assignment of Short Haul Capacity), and the resulting cost consequences; VECC agrees with the remainder of the settlement. FRPO does not oppose, but takes no position on, part 2 of the Terms of Settlement (Replacement of Peaking Services); FRPO agrees with the remainder of the settlement. All other members of the Working Group or the Consultative Group agree with the settlement set out in this Settlement Agreement.

DATED at Toronto, Ontario July 15, 2010.

Filed: 2010-07-19
EB-2010-0231
Exhibit C
Tab 1
Schedule 1
Appendix A

ENBRIDGE

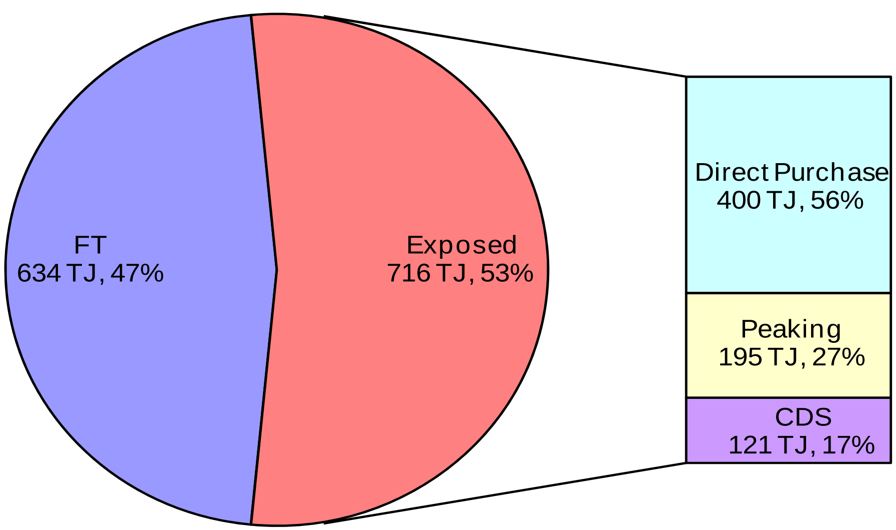
EGD Presentation to Stakeholders on System Reliability Issue

June 15, 2010

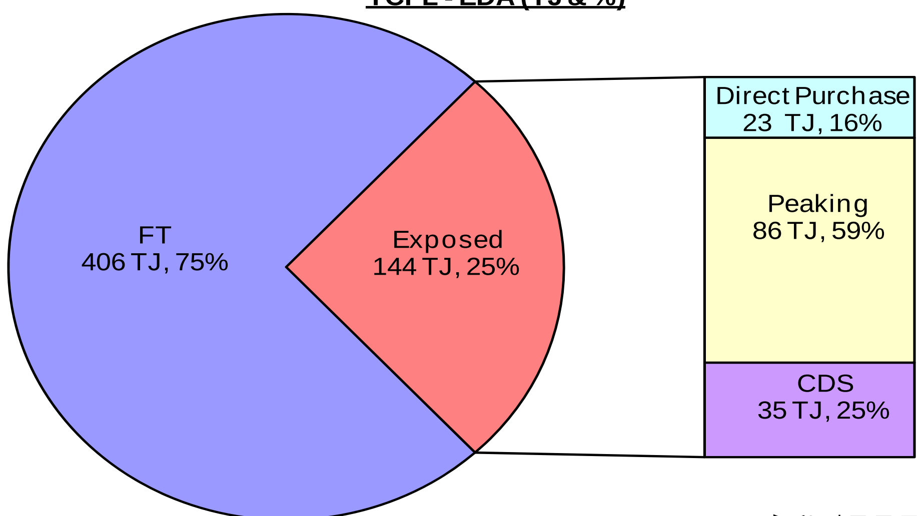
System Reliability Issue as identified by Enbridge

- Extensive use of TCPL's discretionary (non-FT) services to meet firm service commitments to end use customers creates a system reliability concern on peak day
- Use of discretionary transport exceeds 50% and 20% of TCPL deliveries in the CDA and EDA respectively on peak day
- With the exception of pre-contracted STFT, other discretionary services are less reliable in respect of terms of service under extreme weather and pipeline outage situations
- Upstream pipeline outages are often correlated with extreme weather events particularly in low utilization situations
- A supply shortfall in the franchise could result in loss of service to end use customers

TCPL - CDA (TJ & %)



TCPL - EDA (TJ & %)



Description of TCPL Discretionary Services

- Not all discretionary services are of the same quality
- Pre-contracted STFT is closest in quality to FT

	Pros	**Cons**
STFT	High priority High availability if pre-contracted	Lower availability in event of extreme weather or outages if not pre-contracted Not renewable
Upstream Diversion	High priority	Requires deal with FT holder
Downstream Diversion		Low priority
IT		Lowest priority

Recent Outages and Potential Impact on EGD Customers

- In 2009 TCPL had two outages
  - In Jan 2009, TCPL had a capacity reduction of 600 TJ due to loss of compression. Supply shortfall at the timely window was confirmed at subsequent intra day windows
  - In Sept 2009, TCPL had a capacity reduction of ~1770 TJ due to line break. Given the prevailing demand conditions, there was no impact on supply

- Assuming no discretionary services were successfully acquired to serve EGD's franchise, the table below shows the maximum potential supply shortfall of these events on peak day
  - A residential customer consumes 1 GJ on peak day. The supply shortfall below could result in an equivalent number of residential customers losing service
  - An outage to 100,000 residential customers could take up to 2 weeks to restore

Upstream Pipeline Capacity Outage Scenario (GJ)	**600,000** Jan 2009	**1,770,000** Sep 2009
EGD potential GJ shortfall/equivalent residential customer impact	176,000	860,000

ENBRIDGE

How can EGD's System Reliability Concerns be Addressed in the Longer Term? (In Response to the Board's Direction)

- Firm Transport
  - Ensure that a significant proportion of peak day requirements are met through FT and pre-contracted winter period STFT
- Load Shedding
  - Ensure that Large Volume customers who fail to deliver cease consumption
  - Verify that interruptible customers are truly able to cease consumption or switch to an alternate fuel rather than rely solely on curtailment delivered supplies
- Changes to Turnback Policy
  - Turnback capacity must be replaced with alternative contracted firm transportation of equivalent quality to TCPL FT capacity
  - EGD may reduce FT Turnback volume if it reduces flexibility to meet winter demand using TCPL's Storage Transportation Service (STS)

System Reliability Working Committee Presentation to Stakeholders

June 15, 2010

AGENDA

1. Description of EGD Proposal

2. Description of Components, Rationale and Customer Impacts of EGD Proposal

3. Proposal Matrix – Impact on System Reliability, Ratepayer Costs and Implementation

4. Impact of the Proposal on System Reliability

5. Conclusion

EGD – Original Proposal

EGD Objectives

- Address system reliability at reasonable cost
- Minimize impact on competitive market
- Establish longer term resolution

EGD Proposal to Working Committee

✓ Mass Market retailers receive a temporary assignment of 50,000 GJ/d of short haul capacity to CDA. EGD replaces assignment with STFT for five months for sales customers

✓ EGD replaces 200,000 GJ/d of peaking supplies with STFT for three months

X *Acquire 80,000 GJ/d of STFT for Three Months to Provide a Reserve Margin*

✓ Rate Handbook & Contract Changes to LV Firm Service

✓ Increase Effectiveness of Curtailment

✓ Changes to Turnback Policy

1. Assignment of Shorthaul Component

- EGD will provide a temporary assignment (Nov 1) to mass market retailers of 50,000 GJ/d of short haul capacity from Dawn to CDA

- EGD will replace the assignment with STFT (Nov to March) from Empress, AB to EGD CDA or, if economic, equivalent firm transportation

- Assignment criteria
  - Mandatory for agents with General Service Ontario T MDV delivery obligations of 1500 GJ/d or more
  - ~30% of MDV obligation based on current profile
  - Capped at 50,000 Gj/d
  - Reviewed prior to Nov 1 each year to reflect customer migration
    - *Assignment remains at 50,000 GJ/d, or*
    - *Assignment adjusted downward such that assigned short haul capacity represents no more than 40% of total mass market OTS volumes*

1. Shorthaul Component and Rationale

Underlying Rationale

- Increase in firm transport utilization by mass market direct purchase customers
- Increased access to competitive Dawn supplies for mass market direct purchase customers under the proposal would better match the currently diversified portfolio for Sales and Western T customers
- Increased security of supply for all customers

Customer Impact

- Incremental gas costs of $5.4M based on current tolls and basis differentials
- Sales and Western T customers incur an increase in their transportation costs but benefit from increased security of supply for all customers
- Ontario T mass market retailers/customers receive access to lower cost firm transport assuming currently prevailing tolls and basis differentials

1. Shorthaul Component - Customer Impact*

TYPICAL CUSTOMER VOLUME PROFILES	Annual Volume	Unit Rate ($/m3)	Annual Bill Impact $	Burner Tip Annual Bill	Impact
GENERAL SERVICE	m^3	Sales & Western T		$	%
RATE 1 RESIDENTIAL					
Htg. & Wtr.Htg.	3,064	0.0009	3	1,201	0.2%
RATE 6 COMMERCIAL					
Heating & Other Uses	22,606	0.0009	20	7,671	0.3%
Medium Customer	169,563	0.0009	149	50,234	0.3%
CONTRACT SERVICE					
RATE 100					
Commercial - small size	339,188	0.0009	298	103,577	0.3%
RATE 145					
Commercial - small size	339,188	0.0009	313	94,289	0.3%
RATE 110					
Industrial - small size, 50% LF	598,568	0.0010	602	166,913	0.4%
RATE 115					
Industrial - avg. size	4,299,152	0.0010	4,435	1,120,056	0.4%
RATE 135					
Industrial - Seasonal Firm	598,567	0.0010	625	151,625	0.4%
RATE 170					
Industrial - avg. size, 50% LF	9,976,121	0.0010	9,746	2,421,577	0.4%

- Assumes EB-2010-0048 rates
- Assumes current TCPL tolls, analysis reflects current basis spreads between AECO, Chicago and Dawn. Impacts are subject to change based on market conditions at the time of implementation

2. Firming of Peaking Supply Component

- EGD replaces 200,000 GJ/d of peaking supplies with STFT for three winter months from Empress, or equivalent firm transportation, if economic
  - Represents ~75% of design day peaking requirements for 2009 & 2010
- Utilized in lieu of equivalent amount of peaking supplies in peak and near-peak conditions
- When economic, STFT will be used to displace other winter purchases

2. Peaking Rationale and Customer Impact

Underlying Rationale

- EGD has determined that its delivered peaking supplies have been less than firm in extreme weather/system outage situations
- Increase system reliability by reducing reliance on peaking supplies delivered through lower priority discretionary services

Customer Impact

- Incremental gas costs of $17.8M based on current tolls and basis differentials
- Cost impact of firming up peaking supplies borne mostly by heat sensitive sales and direct purchase customers
- Benefits associated with displacement of other winter purchases allocated by volume to sales and Western-T service customers
- Costs and benefits will be allocated to customers using the Board approved cost allocation and rate design methodology

2. Peaking Supply Component Customer Impact*

TYPICAL CUSTOMER VOLUME PROFILES	Annual Volume	Unit Rate $/m³		Annual Bill Impact $		Burner Tip %	
GENERAL SERVICE	m^3	Sales & Western T	Ontario T	Sales & Western T	Ontario T	Sales & Western T	Ontario T
RATE 1 RESIDENTIAL							
Htg. & Wtr.Htg.	3,064	0.0017	0.0029	5	9	0.4%	0.7%
RATE 6 COMMERCIAL							
Heating & Other Uses	22,606	0.0015	0.0026	34	60	0.4%	0.8%
Medium Customer	169,563	0.0015	0.0026	256	447	0.5%	0.9%
CONTRACT SERVICE							
RATE 100							
Commercial - small size	339,188	0.0015	0.0026	511	894	0.5%	0.9%
RATE 145							
Commercial - small size	339,188	(0.0011)	0.0000	(382)	0	-0.4%	0.0%
RATE 110							
Industrial - small size, 50% LF	598,568	(0.0008)	0.0003	(484)	191	-0.3%	0.1%
RATE 115							
Industrial - avg. size	4,299,152	(0.0010)	0.0001	(4,307)	541	-0.4%	0.0%
RATE 135							
Industrial - Seasonal Firm	598,567	(0.0011)	0.0000	(675)	0	-0.4%	0.0%
RATE 170							
Industrial - avg. size, 50% LF	9,976,121	(0.0011)	0.0000	(11,249)	0	-0.5%	0.0%

- Assumes EB-2010-0048 rates
- Assumes current TCPL tolls, analysis reflects current basis spreads between AECO, Chicago and Dawn. Impacts are subject to change based on market conditions at the time of implementation.

3. Reserve Margin Component (not included in Settlement)

- Acquire 80,000 GJ/d of STFT for three months to provide a Reserve Margin
- Reserve margin would have been used for coverage in different scenarios, such as
  - one DD over current design day of 39.5 DD
  - higher than average wind conditions on current design day
  - failure to deliver (>300,000 GJ/d of direct shipper gas uses discretionary services)
- Total costs of $11.5 million based on current tolls and basis differentials
- Costs would have been allocated to all customers to match benefits to all customers through increased security of supply
- EGD agreed to withdraw this component for purposes of settlement

3. Reserve Margin - Customer Impact*

TYPICAL CUSTOMER VOLUME PROFILES	Annual Volume	Unit Rate $/m³	Annual Bill Impact $	Burner Tip %
GENERAL SERVICE	m³	All Customers	All Customers	All Customers
RATE 1 RESIDENTIAL				
Htg. & Wtr.Htg.	3,064	0.0010	3	0.3%
RATE 6 COMMERCIAL				
Heating & Other Uses	22,606	0.0010	24	0.3%
Medium Customer	169,563	0.0010	177	0.4%
CONTRACT SERVICE				
RATE 100				
Commercial - small size	339,188	0.0010	354	0.3%
RATE 145				
Commercial - small size	339,188	0.0010	354	0.4%
RATE 110				
Industrial - small size, 50% LF	598,568	0.0010	624	0.4%
RATE 115				
Industrial - avg. size	4,299,152	0.0010	4,485	0.4%
RATE 135				
Industrial - Seasonal Firm	598,567	0.0010	624	0.4%
RATE 170				
Industrial - avg. size, 50% LF	9,976,121	0.0010	10,407	0.4%

- Assumes EB-2010-0048 rates
- Assumes current TCPL tolls, analysis reflects current basis spreads between AECO, Chicago and Dawn. Impacts are subject to change based on market conditions at the time of implementation.

4. LV Component and Rationale

- Rate Handbook Changes
  - Large Volume customers obligated to deliver Mean Daily Volume
  - Large Volume customers have to provide 2 business days notice of suspension of deliveries
    - *Shortfall in delivered volume without adequate notice will be treated as Unauthorized Supply Overrun Volume*
    - *Consumption of Unauthorized Supply Overrun Volume could result in cessation of service*

- Contract Changes
  - EGD will ensure contractual ability to suspend service to large volume customers in an Unauthorized Supply Overrun situation

Underlying Rationale

- Provides EGD with the contractual ability to shed load, targeted to customers who fail to deliver
  - Provides Gas Control timely information in forecasting demand and planning supply
  - Requires large volume customers to accept the consequences of their gas supply and transportation contracting practices

5. Curtailment Component and Rationale

- Customer must demonstrate ability to curtail or use backup fuel rather than relying solely on Curtailment Delivered Supply (CDS)

- Changes to remedies should a customer fail to deliver/curtail during curtailment and takes Unauthorized Supply Overrun Gas
  - Customer pays 150% of highest price on each day applied to unauthorized volume
  - Customer forfeits curtailment credits for the respective winter season (December to March inclusive)
  - Customer taking a material volume of Unauthorized Supply Overrun Gas may forfeit the right to receive service under an interruptible rate

- Elimination of 72 hour curtailment notice service under Rate 145
  - No impact on credits for other interruptible customers

Underlying Rationale

- Provides Gas Control more effective ability to rely on curtailment under peak conditions
  - Strengthen obligations to deliver/curtail under this service
  - Curtailment of customers with 72 hours notice no longer provides benefit under peak day conditions

6. Turnback Component

- Applicability of turnback policy in the Rate Handbook will include Ontario T and Western T service

- Provisions of Rider A* that have become effective on a date will not apply retroactively to turnback requests that have been accepted

- EGD will accommodate turnback of TCPL long haul capacity, only if it can do so in accordance with the following circumstances
  - Turnback is replaced with alternative contracted firm capacity (primary or assigned) of equivalent quality to TCPL FT
  - Turnback volume may be reduced to address the impact of stranded costs, other transitional or incremental gas costs arising from reduced flexibility to meet winter demand using TCPL's STS service
  - EGD maintains the integrity and reliability of the gas distribution system while respecting the sanctity of contracts

<u>Background</u>

- EGD has offered turnback of TCPL FT capacity over the last decade**
- The direct purchase community has subscribed to turnback in large quantities
- Ontario T assignments as of November 2010 equal ~30,000 GJ
- Western T assignments as of November 1, 2010 equal ~141,000 GJ
  - 91% of Western-T capacity is held on behalf of mass market customers

* Rider A Transportation Service Rider EGD Rate Handbook
**Except in April 2009

6. Turnback Rationale

- A change to current Turnback Policy is required to support the long term resolution
- Further turnback of TCPL FT long haul capacity will impact EGD's operational ability to meet winter demand using TCPL's STS
- EGD will accommodate requests if FT turnback capacity is replaced with alternative, contracted firm transportation (primary capacity or assignment) of equivalent quality to TCPL FT capacity (Note: dependent upon operational considerations stated in bullet #2 above)

4. Combined Shorthaul & Peaking Supply Components - Customer Impact

TYPICAL CUSTOMER VOLUME PROFILES	Annual Volume	Unit Rate $/m³		Annual Bill Impact $		Burner Tip %	
GENERAL SERVICE	m³	Sales & Western T	Ontario T	Sales & Western T	Ontario T	Sales & Western T	Ontario T
RATE 1 RESIDENTIAL							
Htg. & Wtr.Htg.	3,064	0.0026	0.0029	8	9	0.7%	0.7%
RATE 6 COMMERCIAL							
Heating & Other Uses	22,606	0.0024	0.0026	54	60	0.7%	0.8%
Medium Customer	169,563	0.0024	0.0026	405	447	0.8%	0.9%
CONTRACT SERVICE							
RATE 100							
Commercial - small size	339,188	0.0024	0.0026	809	894	0.8%	0.9%
RATE 145							
Commercial - small size	339,188	(0.0002)	0.0000	(69)	0	-0.1%	0.0%
RATE 110							
Industrial - small size, 50% LF	598,568	0.0002	0.0003	118	191	0.1%	0.1%
RATE 115							
Industrial - avg. size	4,299,152	0.0000	0.0001	129	541	0.0%	0.0%
RATE 135							
Industrial - Seasonal Firm	598,567	(0.0001)	0.0000	(50)	0	0.0%	0.0%
RATE 170							
Industrial - avg. size, 50% LF	9,976,121	(0.0002)	0.0000	(1,503)	0	-0.1%	0.0%

- Assumes EB-2010-0048 rates
- Assumes current TCPL tolls, analysis reflects current basis spreads between AECO, Chicago and Dawn. Impacts are subject to change based on market conditions at the time of implementation.

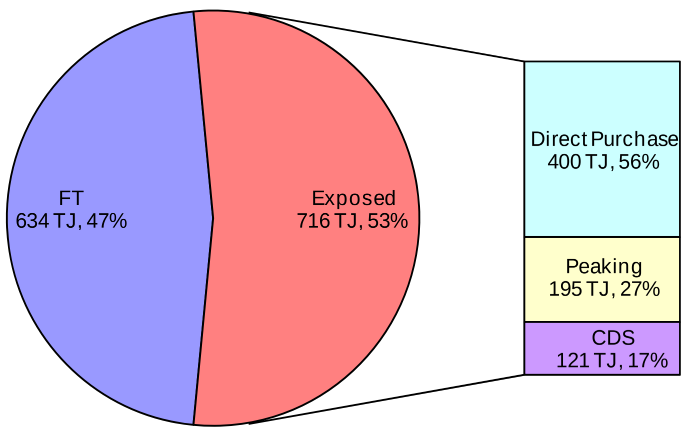
Proposal Matrix

Impact of Proposal	System Reliability		Ratepayer Costs	Implementation
Component	**Firm Transport**	**Load Shedding**	**Ratepayer Costs**	**Implementation**
1. Dawn-CDA Short Haul FT Capacity - Assign 50,000 GJ/d SH FT to Mass Market - EGD contracts STFT 5 months	Positive		Borne by sales and western T customers. Mass market direct purchase customers benefit	Nov 1, 2010
2. Peaking replacement (partial) - Replace 200,000 of peaking with STFT for 3 Mths	Positive		Borne by heat sensitive sales and direct purchase customers. Partial offset for sales and western T customers	Nov 1, 2010
3. Contract changes to LV Firm Service		Positive	Tightening of contract terms	Jan 1, 2011 or earlier
4. Increase Curtailment Effectiveness		Positive	Tightening of contract terms	Jan 1, 2011 or earlier
5. Turnback Policy Changes	Positive		Tightening of contract terms	April 2011

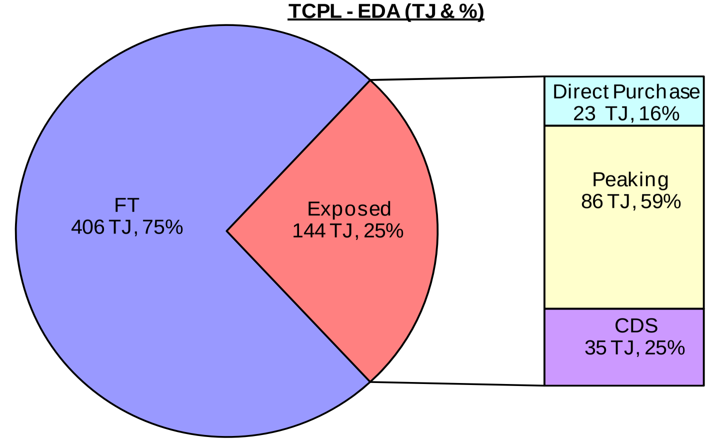
Impact of the Proposal on System Reliability

- The long term resolution will significantly reduce reliance on “less assured” forms of discretionary services in the current market environment

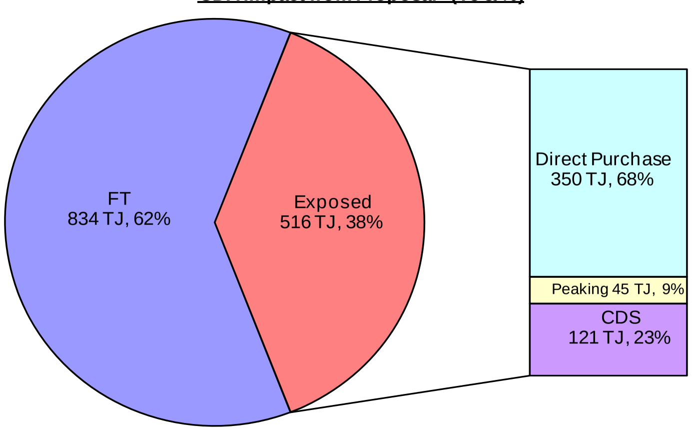
TCPL - CDA (TJ & %)



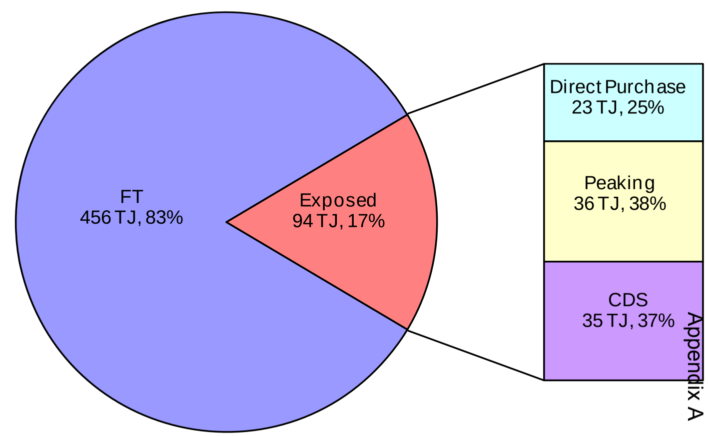
TCPL - EDA (TJ & %)



CDA Impact from Proposal - (TJ & %)



EDA Impact from Proposal - (TJ & %)



Note : Winter season STFT is treated as Firm. Exposure quantities does not reflect benefits from changes to large volume firm and interruptible rates/contracts

Conclusion

- The Proposal, if approved, will
  - Replace the Board approved interim resolution
  - Result in manageable cost impacts
  - Minimize competitive impacts
  - Provide a long term resolution in current upstream market environment
- Proposal will be reviewed if there is a material change in market circumstances
  - Construction of new facilities that increase the availability of short haul FT to EGD’s franchise area
  - Material change in the availability of TCPL discretionary services
  - Conclusions from future Board process that addresses matters relevant to Enbridge's system reliability

Discussion, Q&A, and follow up …

- The afternoon of June 15 is scheduled for an extended discussion and Q&A session of the proposed settlement

- Any questions that remain unanswered at the end of day can be submitted by June 18 (?) for a response to be provided by June 22 (?)

- A follow-up session with the Broader Group can be provided for, if required, on June 23 (?)

- At the completion of these proposed steps, parties will be canvassed to indicate whether or not they are in support of the settlement agreement

Next Steps - Process

- Enbridge will apply to the Board for approval of a settlement that results from the consultative process

- Enbridge will propose that the Board give such notice as the Board deems appropriate and that the process for approval be expedited in light of the agreement reached by the consultative

- Enbridge's filing in support of the request for approval will include a description of the consultative process, to which will be attached
  - Meeting minutes and presentations; and
  - Where appropriate, material exchanged as part of the consultative process that sheds light on the discussions and presentations at the meetings

RATE HANDBOOK

ENBRIDGE GAS DISTRIBUTION

HANDBOOK OF RATES AND DISTRIBUTION SERVICES

INDEX

Part I

GLOSSARY OF TERMS

In this Handbook of Rates and Distribution Services, each term set out below shall have the meaning set out opposite it:

Annual Turnover Volume ("ATV"): The sum of the contracted volumes injected into and withdrawn from storage by an applicant within a contract year.

Annual Volume Deficiency: The difference between the Minimum Annual Volume and the volume actually taken in a contract year, if such volume is less than the Minimum Annual Volume.

Applicant: The party who makes application to the Company for one or more of the services of the Company and such term includes any party receiving one or more of the services of the Company.

Authorized Volume: In regards to Sales Service Agreements, the Contract Demand.

In regards to Bundled Transportation Service arrangements, the Contract Demand (CD) less the amount by which the Applicant's Mean Daily Volume (MDV) exceeds the Daily Delivered Volume (Delivery) and less the volume by which the Applicant has been ordered to curtail or discontinue the use of gas (Curtailment Volume) or otherwise represented as:

CD – (MDV – Delivery) – Curtailment Volume

Back-stopping: A service whereby alternative supplies of gas may be available in the event that an Applicant's supply of gas is not available for delivery to the Company.

Banked Gas Account: A record of the amount of gas delivered by the Applicant to the Company in respect of a Terminal Location (credits) and of volume of gas taken by the Applicant at the Terminal Location (debits)

Billing Contract Demand: Applicable only to new customers who take Dedicated Service under Rate 125. The Company and the Applicant shall determine a Billing Contract Demand which would result in annual revenues over the term of the contract that would enable the Company to recover the invested capital, return on capital, and O&M costs of the Dedicated Service in accordance with its system expansion policies.

Billing Month: A period of approximately thirty (30) days following which the Company renders a bill to an applicant. The billing month is determined by the Company's monthly Reading and Billing Schedule. With respect to rate 135 LVDC's, there are eight summer months and four winter months.

Board: Ontario Energy Board. (OEB)

Bundled Service: A service in which the demand for natural gas at a Terminal Location is met by the Company utilizing Load balancing resources.

Buy/Sell Arrangement: An arrangement, the terms of which are provided for in one or more agreements to which one or more of an end user of gas (being a party that buys from the Company gas delivered to a Terminal Location), an affiliate of an end user and a marketer, broker or agent of an end user is a party and the Company is a party, and pursuant to which the Company agrees to buy from the end user or its affiliate a supply of gas and to sell to the end user gas delivered to a Terminal Location served from the gas distribution network. The Company will not enter into any new buy/sell agreement after April 1, 1999.

Buy/Sell Price: The Price per cubic meter which the Company would pay for gas purchased pursuant to a Buy/Sell Arrangement in which the purchase takes place in Ontario.

Commodity Charge: A charge per unit volume of gas actually taken by the Applicant, as distinguished from a demand charge which is based on the maximum daily volume an Applicant has the right to take.

Company: Enbridge Gas Distribution Inc.

Contract Demand: A contractually specified volume of gas applicable to service under a particular Rate Schedule for each Terminal Location which is the maximum volume of gas the Company is required to deliver on a daily basis under a Large Volume Distribution Contract.

Cubic Metre ("m^3"): That volume of gas which at a temperature of 15 degrees Celsius and at an absolute pressure of 101.325 kilopascals ("kPa") occupies one cubic metre. "10^3m^3" means 1,000 cubic metres.

Curtailment: An interruption in an Applicant's gas supply at a Terminal Location resulting from compliance with a request or an order by the Company to discontinue or curtail the use of gas.

Curtailment Credit: A credit available to interruptible customers to recognize the benefits they provide to the system during the winter months.

Curtailment Delivered Supply (CDS): An additional volume of gas, in excess of the Applicant's Mean Daily Volume and determined by mutual agreement between the Applicant and the Company, which is Nominated and delivered by or on behalf of the Applicant to a point of interconnection with the Company's distribution system on a day of Curtailment.

Customer Charge: A monthly fixed charge that reflects being connected to the gas distribution system.

Daily Consumption VS Gas Quantity: The volume of natural gas taken on a day at a Terminal Location as measured by daily metering equipment or, where the Company does not own and maintain daily metering equipment at a Terminal Location, the volume of gas taken within a billing period divided by the number of days in the billing period.

Daily Delivered Volume: The volume of gas accepted by the Company as having been delivered by an Applicant to the Company on a day.

Dedicated Service: An Unbundled Service provided through a gas distribution pipeline that is initially constructed to serve a single customer, and for which the volume of gas is measured through a billing meter that is directly connected to a third party transporter or other third party facility, when service commences.

Delivery Charge: A component of the Rate Schedule through which the Company recovers its operating costs.

Demand Charge: A fixed monthly charge which is applied to the Contract Demand specified in a Service Contract.

Demand Overrun: The amount of gas taken at a Terminal Location exceeding the Contract Demand.

Direct Purchase: Natural gas supply purchase arrangements transacted directly between the Applicant and one or more parties, including the Company.

Disconnect and Reconnect Charges: The charges levied by the Company for disconnecting or reconnecting an Applicant from or to the Company's distribution system.

Diversion: Delivery of gas on a day to a delivery point different from the normal delivery point specified in a Service Contract.

Firm Service: A service for a continuous delivery of gas without curtailment, except under extraordinary circumstances.

Firm Transportation ("FT"): Firm Transportation service offered by upstream pipelines to move gas from a receipt point to a delivery point, as defined by the pipeline.

Force Majeure: Any cause not reasonably within the control of the Company and which the Company cannot prevent or overcome with reasonable due diligence, including:

(a) physical events such as an act of God, landslide, earthquake, storm or storm warning such as a hurricane which results in evacuation of an affected area, flood, washout, explosion, breakage or accident to machinery or equipment or lines of pipe used to transport gas, the necessity for making repairs to or alterations of such machinery or equipment or lines of pipe or inability to obtain materials, supplies (including a supply of services) or permits required by the Company to provide service;

(b) interruption and/or curtailment of firm transportation by a gas transporter for the Company;

(c) acts of others such as strike, lockout or other industrial disturbance, civil disturbance, blockade, act of a public enemy, terrorism, riot, sabotage, insurrections or war, as well as physical damage resulting from the negligence of others;

(d) in relation to Load Balancing, failure or malfunction of any storage equipment or facilities of the Company; and

(e) governmental actions, such as necessity for compliance with any applicable laws.

Gas: Natural Gas.

Gas Delivery Agreement: A written agreement pursuant to which the Company agrees to transport gas on the Applicant's behalf to a specified Terminal Location.

Gas Distribution Network: The physical facilities owned by the Company and utilized to contain, move and measure natural gas.

Gas Sale Contract: A written agreement pursuant to which the Company agrees to supply and deliver gas to a specified Terminal Location.

Gas Supply Charge: A charge for the gas commodity purchased by the applicant.

Gas Supply Load Balancing Charge: A charge in the Rate Schedules where the Company recovers the cost of ensuring gas supply matches consumption on a daily basis.

General Service Rates: The Rate Schedules applicable to those Bundled Services for which a specific contract between the Company and the Applicant is not generally required. The General Service Rates include Rates 1, 6, and 9 of the Company.

Gigajoule ("GJ"): See Joule.

Hourly Demand: A contractually specified volume of gas applicable to service under a particular Rate Schedule which is the maximum volume of gas the Company is required to deliver to an Applicant on a hourly basis under a Service Contract.

Imperial Conversion Factors:

Volume:

1,000 cubic feet (cf)	=	1 Mcf
	=	28.32784 cubic metres (m^3)
1 billion cubic feet (cf)	=	28.32784 $10^6 m^3$

Pressure:

1 pound force per square inch (p.s.i.)	=	6.894757 kilopascals (kPa)
1 inch Water Column (in W.C.) (60°F)	=	0.249 kPa (15.5°C)
1 standard atmosphere	=	101.325 kPa

Energy:

1 million British thermal units	=	1 MMBtu
	=	1.055056 gigajoules (GJ)
948,213.3 Btu	=	1 GJ

Monetary Value:

$1 per Mcf	=	$0.03530096 per m^3
$1 per MMBtu	=	$0.9482133 per GJ

Interruptible Service: Gas service which is subject to curtailment for either capacity and/or supply reasons, at the option of the Company.

Intra-Alberta Service: Firm transportation service on the Nova pipeline system under which volumes are delivered to an Intra-Alberta point of acceptance.

Joule ("J"): The amount of work done when the point of application of a force of one newton is displaced a distance of one metre in the direction of the force. One megajoule ("MJ") means 1,000,000 joules; one gigajoule ("GJ") means 1,000,000,000 joules.

Large Volume Distribution Contract: (LVDC): A written agreement pursuant to which the Company agrees to supply and deliver gas to a specified Terminal Location.

Large Volume Distribution Contract Rates: The Rate Schedules applicable for annual consumption exceeding 340,000 cubic metres of gas per year and for which a specific contract between the Company and the Applicant is required.

Load-Balancing: The balancing of the gas supply to meet demand. Storage and other peak supply sources, curtailment of interruptible services, and diversions from one delivery point to another may be used by the Company.

Make-up Volume: A volume of gas nominated and delivered, pursuant to mutually agreed arrangements, by an Applicant to the Company for the purpose of reducing or eliminating a net debit balance in the Applicant's Banked Gas Account.

Mean Daily Volume (MDV): The volume of gas which an Applicant who delivers gas to the Company, under a T-Service arrangement, agrees to deliver to the Company each day in the term of the arrangement.

Metric Conversion Factors:

Volume:		
1 cubic metre (m^3)	=	35.30096 cubic feet (cf)
1,000 cubic metres	=	10^3m^3
	=	35,300.96 cf
	=	35.30096 Mcf
28.32784 m^3	=	1 Mcf
Pressure:		
1 kilopascal (kPa)	=	1,000 pascals
	=	0.145 pounds per square inch (p.s.i.)
101.325 kPa	=	one standard atmosphere
Energy:		
1 megajoule (MJ)	=	1,000,000 joules
	=	948.2133 British thermal units (Btu)
1 gigajoule (GJ)	=	948,213.3 Btu
1.055056 GJ	=	1 MMBtu
Monetary Value:		
$1 per 10^3m^3	=	$0.02832784 per Mcf
$1 per gigajoule	=	$1.055056 per MMBtu

Minimum Annual Volume: The minimum annual volume as stated in the customer's contract, also Section E.

Natural Gas: Natural and/or residue gas comprised primarily of methane.

Nominated Volume: The volume of gas which an Applicant has advised the Company it will deliver to the Company in a day.

Nominate, Nomination: The procedure of advising the Company of the volume which the Applicant expects to deliver to the Company in a day.

Ontario Energy Board: An agency of the Ontario Government which, amongst other things, approves the Company's Rate Schedules (Part V of this HANDBOOK) and the matters described in Parts III and IV of this HANDBOOK.

Point of Acceptance: The point at which the Company accepts delivery of a supply of natural gas for transportation to, or purchase from, the Applicant.

Rate Schedule: A numbered rate of the Company as fixed or approved by the OEB. that specifies rates, applicability, character of service, terms and conditions of service and the effective date.

Seasonal Credit: A credit applicable to Rate 135 customers to recognize the benefits they provide to the storage operations during the winter period.

Service Contract: An agreement between the Company and the Applicant which describes the responsibilities of each party in respect to the arrangements for the Company to provide Sales Service or Transportation Service to one or more Terminal Locations.

System Sales Service: A service of the Company in which the Company acquires and sells to the Applicant the Applicant's natural gas requirements.

T-Service: Transportation Service.

Terminal Location: The building or other facility of the Applicant at or in which natural gas will be used by the Applicant.

Transportation Service: A service in which the Company agrees to transport gas on the Applicant's behalf to a specified Terminal Location.

Unbundled Service: A service in which the demand for natural gas at a Terminal Location is met by the Applicant contracting for separate services (upstream transportation, load balancing/storage, transportation on the Company's distribution system) of which only Transportation Service is mandatory with the Company.

Western Canada Buy Price: The price per cubic metre which the Company would pay for gas pursuant to a Buy/Sell Agreement in which the purchase takes place in Western Canada.

PART II

RATES AND SERVICES AVAILABLE

The provisions of this PART II are intended to provide a general description of services offered by the Company and certain matters relating thereto. Such provisions are not definitive or comprehensive as to their subject matter and may be changed by the Company at any time without notice.

SECTION A - INTRODUCTION

1. In Franchise Services

Enbridge Gas Distribution provides in franchise services for the transportation of natural gas from the point of its delivery to Enbridge Gas Distribution to the Terminal Location at which the gas will be used. The natural gas to be transported may be owned by the Applicant for service or by the Company. In the latter case, it will be sold to the customer at the outlet of the meter located at the Terminal Location.

Applicants may elect to have the Company provide all-inclusively the services which are mutually agreed to be required or they may select (from the 300 series of rates, and Rate 125) only the amounts of those services which they consider they need.

The all-inclusive services are provided pursuant to Rates 1, 6 and 9, ("the General Service Rates") and Rates 100, 110, 115, 135, 145, and 170 ("the Large Volume Service Rates"). Individual services are available under Rates 125, 300, 315, and 316 ("the Unbundled Service Rates").

Service to residential locations is provided pursuant to Rate 1.

Service which may be interrupted at the option of the Company is available, at rates lower than would apply for equivalent service under a firm rate schedule, pursuant to Rates 145, 170. Under all other rate schedules, service is provided upon demand by the Applicant, i.e., on a firm service basis.

2. Ex-Franchise Services

Enbridge Gas Distribution provides ex-franchise services for the transportation of natural gas through its distribution system to a point of interconnection with the distribution system of other distributors of natural gas. Such service is provided pursuant to Rate 200 and provides for the bundled transportation of gas owned by the Company, owned by customers of that distributor, or owned by that distributor.

For the purposes of interpreting the terms and conditions contained in this Handbook of Rates and Distribution Services the ex - franchise distributor shall be considered to be the applicant for the transportation of its customer owned gas and shall assume all the obligations of transportation as if it owned the gas.

Nominations for transportation service must specify whether the volume to be transported is to displace firm or interruptible demand or general service.

In addition, the Company provides Compression, Storage, and Transmission services on its Tecumseh system under Rates 325, 330 and 331.

SECTION B - DIRECT PURCHASE ARRANGEMENTS

Applicants who purchase their natural gas requirements directly from someone other than the Company or who are brokers or agents for an end user, may arrange to transport gas on the Company's distribution network in conjunction with a Western Buy/Sell Arrangement or pursuant to an Ontario Delivery Transportation Service Arrangement, whether Bundled or Unbundled, or a Western Bundled Transportation Service Arrangement.

B. Western Canada

Buy/Sell in a Western Canada Buy/Sell Arrangement the Applicant delivers gas to a point in Western Canada which connects with the transmission pipeline of TransCanada PipeLines Limited. At that point, the Company purchases the gas from the Applicant at a price specified in Rider 'B' of the rate schedules less the costs for transmission of the gas from the point of purchase to a point in Ontario at which the Company's gas distribution network connects with a transmission pipeline system. The Company will not be entering into any new Western Canada buy/sell arrangements after April 1, 1999.

C. Ontario Delivery T-Service Arrangements

In an Ontario Delivery T-Service Arrangement the Applicant delivers gas, to a contractually agreed-upon point of acceptance in Ontario.

Delivery from the point of direct interconnection with the Company's gas distribution network to a Terminal Location served from the Company's gas distribution network may be obtained by the Applicant either under the Bundled Service Rate Schedules or under the Unbundled Service Rate Schedules.

(i) Bundled T-Service

Bundled T-Service is so called because all of the services required by the Applicant (delivery and load balancing) are provided for the prices specified in the applicable Rate Schedule. In a Bundled T-Service arrangement the Applicant contracts to deliver each day to the Company a Mean Daily Volume of gas. Fluctuations in the demand for gas at the Terminal Location are balanced by the Company.

(ii) Unbundled T-Service

The Unbundled Service Rates allow an Applicant to contract for only such kinds of service as the Applicant chooses. The potential advantage to an Applicant is that the chosen amounts of service may be less than the amounts required by an average customer represented in the applicable Rate Schedule, in which case the Applicant may be able to reduce the costs otherwise payable under Bundled T-Service.

D. Western Delivery T-Service Arrangement

In a Western Delivery T-Service Arrangement the Applicant contracts to deliver each day to a point on the TransCanada PipeLines Ltd. transmission system in Western Canada a Mean Daily Volume of gas plus fuel gas. Delivery from that point to the Terminal Location is carried out by the Company using its contracted capacity on the TransCanada PipeLines Limited. system and its gas distribution network. Unbundled T-Service in Ontario is not available with the Western Delivery Option.

An Applicant desiring to receive Transportation Service or to establish a Buy/Sell Agreement must first enter into the applicable written agreements with the Company.

PART III

TERMS AND CONDITIONS APPLICABLE TO ALL SERVICES

The provisions of this PART III are applicable to, and only to, Sales Service and Transportation Service.

SECTION A - AVAILABILITY

Unless otherwise stated in a Rate Schedule, the Company's rates and services are available throughout the entire franchised area serviced by the Company. Transportation service and/or sales service will be provided subject to the Company having the capacity in its gas distribution network to provide the service requested. When the Company is requested to supply the natural gas to be delivered, service shall be available subject to the Company having available to it a supply of gas adequate to meet the requirement without jeopardizing the supply to its existing customers.

Service shall be made available after acceptance by the Company of an application for service to a Terminal Location at which the natural gas will be used.

SECTION B - ENERGY CONTENT

The price of natural gas sold at a Terminal Location is based on the assumption that each cubic metre of such natural gas contains a certain number of megajoules of energy which number is specified in the Rate Schedules. Variations in cost resulting from the energy content of the gas actually delivered to the Company by its supplier(s) differing from the assumed energy content will be recorded and used to adjust future bills. Such adjustments shall be made in accordance with practices approved from time to time by the Ontario Energy Board.

SECTION C - SUBSTITUTION PROVISION

The Company may deliver gas from any standby equipment provided that the gas so delivered shall be reasonably equivalent to the natural gas normally delivered.

SECTION D - BILLS

Bills will be mailed or delivered monthly or at such other time period as set out in the Service Contract. Gas consumption to which the Company's rates apply will be determined by the Company either by meter reading or by the Company's estimate of consumption where meter reading has not occurred. The rates and charges applicable to a billing month shall be those applicable to the calendar month which includes the last day of the billing month.

SECTION E - MINIMUM BILLS

The minimum bill per month applicable to service under any particular Rate Schedule shall be the Customer Charge plus any applicable Contract Demand Charges for Delivery, Gas Supply Load Balancing, and Gas Supply and any applicable Direct Purchase Administration Charge, all as provided for in the applicable Rate Schedule.

In addition, for service under each of the Large Volume Distribution Contact Rates, if in a contract year a volume of gas equal to or greater than the product of the Contract Demand multiplied by a contractually specified multiple of the Contract Demand ("Minimum Annual Volume") is not taken at the Terminal Location the Applicant shall pay, in addition to the minimum monthly bills, the amount obtained when the difference between the Minimum Annual Volume and the volume taken in the contract year (such difference being the Annual Volume Deficiency) is multiplied by the applicable Minimum Bill Charge(s) as provided for in the applicable Rate Schedule. Notwithstanding the foregoing, the Minimum Annual Volume shall be the greater of the Minimum Annual Volume as determined above and 340,000 m^3.

If gas deliveries to the Terminal Location have been ordered to be curtailed or discontinued in a contract year at the request of the Company and have been curtailed or discontinued as ordered, the Minimum Annual Volume shall be reduced for each day of curtailment or discontinuance by the excess of the Contract Demand over the volume delivered to the Terminal Location on such day.

SECTION F - PAYMENT CONDITIONS

Enbridge Gas Distribution charges are due when the bill is received, which is considered to be three days after the date the bill is rendered, or within such other time period as set out in the Service Contract. A late payment charge of 1.5% per month (19.56% effectively per annum) of all of the unpaid Enbridge Gas Distribution charges, including all applicable federal and provincial taxes, is applied to the account on the seventeenth (17th) day following the date the bill is due.

SECTION G - TERM OF ARRANGEMENT

When gas service is provided and there is no written agreement in effect relating to the provision of such service, the term for which such service is to continue shall be one year. The term shall automatically be extended for a further year immediately following the expiry of any initial one year term or one year extension unless reasonable notice to terminate service is given to the Company, in a manner acceptable to the Company, prior to the expiry of the term. An Applicant receiving such service who temporarily discontinues service in the initial one year term or any one year extension and does not pay all the minimum bills for the period of such temporary discontinuance of service shall, upon the continuance of service, be liable to pay an amount equal to the unpaid minimum bills for such period. When a written agreement is in effect relating to the provision of gas service, the term for which such service is to continue shall be as provided for in the agreement.

SECTION H - RESALE PROHIBITION

Gas taken at a Terminal Location shall not be resold other than in accordance with all applicable laws and regulations and orders of any governmental authority or OEB having jurisdiction.

SECTION I - MEASUREMENT

The Company will install, operate and maintain at a Terminal Location such measurement equipment of suitable capacity and design as is required to measure the volume of gas delivered. Any special conditions for measurement are contained in the General Terms and Conditions which form part of each Large Volume Distribution Contract.

SECTION J - RATES IN CONTRACTS

Notwithstanding any rates for service specified in any Service Contract, the rates and charges provided for in an applicable Rate Schedule shall apply for service rendered on and after the effective date stated in such Rate Schedule until such Rate Schedule ceases to be applicable.

SECTION K - ADVICE RE: CURTAILMENT

The Company, if requested, will advise Applicants taking interruptible service of its estimate of service curtailment for the forthcoming winter. Such estimate will be provided as guidance to the Applicant in arranging for alternate fuel supply requirements. Abnormal weather and/or other unforeseen events may cause greater or lesser curtailment of service than expected.

SECTION L - DAILY DELIVERED VOLUMES

For purposes including that of calculating daily overrun gas volumes, the Company will recognize as having been delivered to it on a given day the sum of:

a) the volume of gas delivered under Intra-Alberta transportation arrangements, if any, plus;

b) the volume of gas delivered under FT transportation arrangements, if any, plus;

SECTION M - AUTHORIZED OVERRUN GAS

If an Applicant requests permission to exceed the Authorized Volume for a day, and such authorization is granted, such gas shall constitute Authorized Overrun Gas. Such gas shall either be sold by the Company to the Applicant pursuant to the provisions of Rate 320 applicable on such day, or, at the Company's sole discretion, under the Rate Schedule the customer is purchasing prior to such request. If the Applicant is supplying their own gas requirements and if the Applicant request and at the Company's sole discretion, such Overrun Gas will be debited to the Applicant's Baked gas Account.

SECTION N - UNAUTHORIZED SUPPLY OVERRUN GAS

If an Applicant for Transportation Service pursuant to the General Service Rates on any day delivers to the Company a Daily Delivered Volume which is less than the Mean Daily Volume, the volume of gas by which the Mean Daily Volume applicable to such day exceeds the Daily Delivered Volume delivered by the Applicant to the Company on such day shall constitute Unauthorized Supply Overrun Gas and shall be deemed to have been taken and purchased on such day. The rate applicable to such volume shall be 150% of the ~~average~~ highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and the EDA delivery areas respectively.

Unauthorized Supply Overrun Gas for a day applicable to a Service Contract with an Applicant for service under the Large Volume Distribution Contract Rates is:

(a) the volume of gas by which the Daily Gas Quantity under the Service Contract on such day exceeds the Authorized Volume for such day, if any

plus

(b) if the day is in the months of December to March inclusive for an Applicant taking service on Rate 135 under Option a) or if the day is in the month of December under Option b), or if the day is a day on or in respect of which the Applicant has been requested in accordance with the Service Contract to curtail or discontinue the use of gas and the Service Contract is in whole or in part for interruptible Transportation Service, the volume of gas, if any, by which

(i) the Mean Daily Volume set out in the Service Contract and is applicable to such day exceeds

(ii) the Daily Delivered Volume delivered by the Applicant to the Company on such day, which excess volume of gas shall be deemed to have been taken and purchased by the Applicant on such day.

The Applicant shall pay the Company for Unauthorized Supply Overrun Gas at the rate applicable to Unauthorized Supply Overrun Gas as provided for in the Rate Schedule(s) applicable to the Service Contract.

An Applicant taking service pursuant to a Gas Delivery Agreement and a Large Volume Distribution Contract Rate must provide two business days notice to the Company of the Applicant's intention to deliver a Daily Delivered Volume which is less than the Mean Daily Volume for a specified time period. Failure to provide proper notice will result in Unauthorized Supply Overrun Gas calculated as the difference between Daily Delivered Volume and the Mean Daily Volume.

Unauthorized Supply Overrun Gas for a day applicable to a Service Contract with an Applicant for service under Rate 125 or Rate 300 shall be determined from the provisions of the applicable Rate Schedule. The Applicant shall pay the Company for Unauthorized Supply Overrun Gas at the rate applicable to Unauthorized Supply Overrun Gas as provided for in the Rate Schedule(s) applicable to the Service Contract.

SECTION O – COMPANY RESPONSIBILTY AND LIABILITY

This Section O applies only to gas distribution service under Rates 1, 6 and 9, and does not replace or supercede the terms in any applicable Service Contract.
The Company shall make reasonable efforts to maintain, but does not guarantee, continuity of gas service to its customers. The Company may, in its sole discretion, terminate or interrupt gas service to customers;

to maintain safety and reliability on, or to facilitate construction, installation, maintenance, repair, replacement or inspection of the Company's facilities; or

for any reason related to dangerous or hazardous circumstances, emergencies or Force Majeure.

The Company shall not be liable for any loss, injury, damage, expense, charge, cost or liability of any kind, whether direct, indirect, special or consequential in nature, (excepting only direct physical loss, injury or damage to a customer or a customer's property, resulting from the negligent acts or omissions of the Company, its employees or agents) arising from or connected with any failure, defect, fluctuation or interruption in the provision of gas service by the Company to its customers.

PART IV

TERMS AND CONDITIONS – DIRECT PURCHASE ARRANGEMENTS

Any Applicant, at the time of applying for service, may elect, in and for the term of any Service Contract, to deliver its own natural gas requirements to the Company and the Company shall deliver gas to a Terminal Location as required by the Applicant, subject to the terms and conditions contained in the applicable Rate Schedule and in the Service Contract. For Buy/Sell Arrangements and Bundled T-Service the deliveries by the Applicant to the Company shall be at the Applicant's estimated mean daily rate of consumption.

Backstopping of an Applicant's natural gas supply for Transportation Service arrangements will be available pursuant to Rate 320 subject to the Company's ability to do so using reasonable commercial efforts. Gas Purchase Agreements in respect to Buy/Sell Arrangements shall specify terms and conditions available to the Company to alleviate certain consequences of the Applicant's failure to deliver the required volume of gas.

The following Terms and Conditions shall apply to, and only to, Transportation Service and/or Gas Purchase Agreements.

SECTION A - NOMINATIONS

An Applicant delivering gas to the Company pursuant to a contract is responsible for advising the Company, by means of a contractually specified Nomination procedure, of the daily volume of gas to be delivered to the Company by or on behalf of the Applicant.

An initial daily volume must be Nominated by a contractually specified time before the first day on which gas is to be delivered to the Company. Any Nomination, once accepted by the Company, shall be considered as a standing nomination applicable to each subsequent day in a contract term unless specifically varied by written notice to the Company.

A contract may specify certain contractual provisions that are applicable in the event that an Applicant either fails to advise of a revised daily nomination or fails to deliver the daily volume so nominated.

A Nominated Volume in excess of the Applicant's Maximum Daily Volume as specified in the Service Contract will not be accepted except as specifically provided for in any contract.

SECTION B - OBLIGATION TO DELIVER

During any period of curtailment or discontinuance of Bundled interruptible Transportation Service as ordered by the Company, any Applicant supplying its own gas requirements must, on such day, deliver to the Company the Mean Daily Volume of gas specified in any Service Contract.

Each Applicant taking service pursuant to a Gas Delivery Agreement and a Large Volume Distribution Contract Rate is obligated to deliver the Mean Daily Volume of gas as specified in any Service Contract, unless the Applicant provides two business days notice to the Company of the Applicant's intention to deliver a Daily Delivered Volume which is less than the Mean daily Volume for a specified time period.

An Applicant taking service on Rate 135 under Option a) must deliver to the Company the Mean Daily Volume of gas specified in the Service Contract in the months of December to March, inclusive.

An Applicant taking service on Rate 135 under Option b) must deliver to the Company the Modified Mean Daily Volume of gas specified in the Service Contract in the month of December.

Applicants taking service on General Service rates pursuant to a Direct Purchase Agreement must, on each day in the term of such agreement, deliver to the Company the Mean Daily Volume of gas specified in such agreement.

SECTION C - DIVERSION RIGHTS

Subject to compliance with the Terms and Conditions of all Required Orders, an Applicant who has entered into a Transportation Service Agreement or Agreements which provide(s) for deliveries to the Company for more than one Terminal Location shall have the right, on such terms and only on such terms as are specified in the applicable Transportation Service Agreement, to divert deliveries from one or more contractually specified Terminal Locations to other contractually specified Terminal Locations.

SECTION D - BANKED GAS ACCOUNT (BGA)

For T-Service Applicants, the Company shall keep a record ("Banked Gas Account") of the volume of gas delivered by the Applicant to the Company in respect of a Terminal Location (credits) and of the volume of gas taken by the Applicant at the Terminal Location (debits). (Any volume of gas sold by the Company to the Applicant in respect to the Terminal Location shall not be debited to the Banked Gas Account). The Company shall periodically report to the Applicant the net balance in the Applicant's Banked Gas Account.

SECTION E - DISPOSITION OF BANKED GAS ACCOUNT (BGA) BALANCES

A. The following Terms and Conditions shall apply to Bundled T-Service:

(a) At the end of each contract year, disposition of any net debit balance in the Banked Gas Account (BGA) shall be made as follows:

The Applicant, by written notice to the Company within thirty (30) days of the end of the contract year, may elect to return to the Company, in kind, during the one hundred and eighty (180) days following the end of the contract year, that portion of any debit balance in the Banked Gas Account as at the end of the contract year not exceeding a volume of twenty times the Applicant's Mean Daily Volume by the Applicant delivering to the Company on days agreed upon by the Company and the Applicant a volume of gas greater than the Mean Daily Volume, if any, applicable to such day under a Service Contract. Any volume of gas returned to the Company as aforesaid shall not be credited to the Banked Gas Account in the subsequent contract year. Any debit balance in the Banked Gas Account as at the end of the contract year which is not both elected to be returned, and actually returned, to the Company as aforesaid shall be deemed to have been sold to the Applicant and the Applicant shall pay for such gas within ten (10) days of the rendering of a bill therefor. The rate applicable to such gas shall be:

(1) for *Bundled Western T-Service*, 120% of the average price over the contracted year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs.

(2) for *Bundled Ontario T-Service*, 120% of the average price over the contracted year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, plus the Company's average transportation cost to its franchise area over the contract year.

(b) A credit balance in the Banked Gas Account as at the end of the contract year must be eliminated in one or more of the following manners, namely:

(i) Subject to clause (ii), if the Applicant continues to take service from the Company under a contract pursuant to which the Applicant delivers gas to the Company and the Applicant so elects (by written notice to the Company within thirty (30) days of the end of the contract year), that portion of such balance which the Applicant stipulates in such written notice and which does not exceed twenty times the Applicant's Mean Daily Volume may be carried forward as a credit to the Banked Gas Account for the next succeeding contract year. Any volume duly elected to be carried forward under this clause shall, and may only, be reduced within the period of one hundred and

Deleted: Unless otherwise authorized by the Company in writing, each Applicant taking service pursuant to an OTS-ABC Gas Delivery Agreement shall meet its obligation to deliver gas to the Company by underpinning a minimum percentage and volume of their gas deliveries with firm transport (which in this section is both Firm Transportation and Short Term Firm Transportation) for the winter period commencing January 1 and ending March 31 (the "winter period"). ¶

Deleted: The minimum amounts to be underpinned by firm transport shall be expressed in both volumetric and percentage terms. For the percentage amount, each Applicant shall calculate the annual percentage of gas deliveries to the Company for each of the immediate past three winter periods which were underpinned by firm transport, and taking the average of these three years' percentages, add ten percentage(1) points to the average to establish the minimal amount of gas deliveries that must be underpinned by firm transport for the winter period (e.g., if the average of the past three years is 50% then the addition of ten points will yield 60%(2)). ¶
¶
No later than November 1 of each year and beginning November 1, 2009, each Applicant shall provide written confirmation to the Company of their gas delivery plans for the winter period, including the amounts to be underpinned by firm transport (expressed in both volumetric and percentage terms) as calculated above.¶

Deleted: (1) If a direct shipper had no deliveries for a given year, then the calculation should exclude that year; if a direct shipper has less than three winter periods, the calculation will be the average of the periods in which deliveries occurred. ¶
(2) The amount shall not exceed 100%. ¶

eighty (180) days ("Adjustment Period") immediately following the contract year, by the Applicant delivering to the Company, on days in the Adjustment Period agreed upon by the Company and the Applicant ("Adjustment Days"), a volume of gas less than the Mean Daily Volume applicable to such day under a Service Contract. Subject to the foregoing, the credit balance in the Banked Gas Account shall be deemed to be reduced on each Adjustment Day by the volume ("Daily Reduction Volume") by which the Mean Daily Volume applicable to such day exceeds the greater of the volume of gas delivered by the Applicant on such day and the Nominated Volume for such day which was accepted by the Company.

(ii) Any portion of a credit balance in the Banked Gas Account which is not eligible to be eliminated in accordance with clause (i), or which the Applicant elects (by written notice to the Company within thirty (30) days of the end of the contract year) to sell under this clause, shall be deemed to have been tendered for sale to the Company and the Company shall purchase such portion at:

(1) for *Bundled Western T*-Service, a price per cubic metre of eighty percent (80%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, less the Company's average transportation cost to its franchise area over the contract year.

(2) for *Bundled Ontario T-Service*, a price per cubic metre of eighty percent (80%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs.

Any volume of gas deemed to have been so tendered for sale shall be deemed to have been eliminated from the credit balance of the Banked Gas Account.

During the Adjustment Period the Company shall use reasonable efforts to accept the Applicant's reduced gas deliveries. Any credit balance in the Banked Gas Account not eliminated as aforesaid in the Adjustment Period shall be forfeited to, and be the property of, the Company, and such volume of gas shall be debited to the Banked Gas Account as at the end of the Adjustment Period.

Subject to its ability to do so, the Company will attempt to accommodate arrangements which would permit adjustments to Banked Gas Account balances at times and in a manner which are mutually agreed upon by the Applicant and the Company.

B. The following Terms and Conditions shall apply to Unbundled Service:

The Terms and Conditions for disposition of Cumulative Imbalance Account balances shall be as specified in the applicable Service Contracts.

RATE NUMBER: 100	FIRM CONTRACT SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of a specified annual volume of natural gas of not less than 340,000 cubic metres to be delivered at a specified maximum daily rate.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$121.52**
Delivery Charge	
Per cubic metre of Contract Demand	**8.1900 ¢/m³**
For the first 14,000 m³ per month	**5.1674 ¢/m³**
For the next 28,000 m³ per month	**3.8084 ¢/m³**
For all over 42,000 m³ per month	**3.2494 ¢/m³**
Gas Supply Load Balancing Charge	**0.4858 ¢/m³**
Transportation Charge per cubic metre	**4.6549 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**21.0876 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the ~~average~~ highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

RATE NUMBER: **100**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

10.2535 ¢/m³

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after April 1, 2010 under Sales Service and Transportation Service. This rate schedule is effective April 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, April 1, 2010 and that indicates as the Board Order, EB-2009-0172, effective January 1, 2010.

RATE NUMBER: **110**	**LARGE VOLUME LOAD FACTOR SERVICE**

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 183 times a specified maximum daily volume of not less than 1,865 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$585.00**
Delivery Charge	
Per cubic metre of Contract Demand	**22.9100 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.6267 ¢/m³**
For all over 1,000,000 m³ per month	**0.4767 ¢/m³**
Gas Supply Load Balancing Charge	**0.1346 ¢/m³**
Transportation Charge per cubic metre	**4.6549 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**21.0244 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the ~~average~~ highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

RATE NUMBER:	**110**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

5.3615 ¢/m³

In determining the Annual Volume Deficiency, the minimum bill multiplier shall not be less than 183.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after April 1, 2010 under Sales Service and Transportation Service. This rate schedule is effective April 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, April 1, 2010 and that indicates as the Board Order, EB-2009-0172, effective January 1, 2010.

RATE NUMBER: **115**	**LARGE VOLUME LOAD FACTOR SERVICE**

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 292 times a specified maximum daily volume of not less than 1,165 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$620.86**
Delivery Charge	
Per cubic metre of Contract Demand	**24.3600 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.3616 ¢/m³**
For all over 1,000,000 m³ per month	**0.2616 ¢/m³**
Gas Supply Load Balancing Charge	**0.0452 ¢/m³**
Transportation Charge per cubic metre	**4.6549 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**21.0244 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the ~~average~~ highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

RATE NUMBER:	115

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

5.0070 ¢/m³

In determining the Annual Volume Deficiency the minimum bill multiplier shall not be less than 292.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after April 1, 2010 under Sales Service and Transportation Service. This rate schedule is effective April 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, April 1, 2010 and that indicates as the Board Order, EB-2009-0172, effective January 1, 2010.

RATE NUMBER: **135**	**SEASONAL FIRM SERVICE**

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 340,000 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure. A maximum of five percent of the contracted annual volume may be taken by the Applicant in a single month during the months of December to March inclusively.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month	
	December to March	**April to November**
Monthly Customer Charge	**$114.82**	**$114.82**
Delivery Charge		
For the first 14,000 m³ per month	**6.7929 ¢/m³**	**2.0929 ¢/m³**
For the next 28,000 m³ per month	**5.5929 ¢/m³**	**1.3929 ¢/m³**
For all over 42,000 m³ per month	**5.1929 ¢/m³**	**1.1929 ¢/m³**
Gas Supply Load Balancing Charge	**0.0000 ¢/m³**	**0.0000 ¢/m³**
Transportation Charge per cubic metre	**4.6549 ¢/m³**	**4.6549 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**21.0869 ¢/m³**	**21.0869 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

The applicant has the option of delivering either Option a) a Mean Daily Volume ("MDV") based on 12 months, or Option b) a Modified Mean Daily Volume ("MMDV") based on nine months of deliveries. Authorized Volumes for the months of January, February and March would be zero under option b).

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the ~~average~~ highest price on each day on which an overrun occurred for the calendar month as published in t Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Failure to deliver a volume of gas equal to the Mean Daily Volume under Option a) set out in the Service Contract during the months of December to March inclusive may result in the Applicant not being eligible for service under this rate in a subsequent contract period, at the Company's sole discretion.

Failure to deliver a volume of gas equal to the Modified Mean Daily Volume under Option b) set out in the Service Contract during the month of December may result in the Applicant not being eligible for service under this rate in a subsequent contract period, at the Company's sole discretion.

EFFECTIVE DATE:	IMPLEMENTATION DATE:	BOARD ORDER:	REPLACING RATE EFFECTIVE:	
April 1, 2010	April 1, 2010	EB-2010-0048	January 1, 2010	Page 1 of 2 Handbook 25

ENBRIDGE

RATE NUMBER: **135**

SEASONAL CREDIT:

Rate per cubic metre of Mean Daily Volume from December to March	$	**0.77 /m³**
Rate per cubic metre of Modified Mean Daily Volume for December	$	**0.77 /m³**

SEASONAL OVERRUN CHARGE:

During the months of December through March inclusively, any volume of gas taken in a single month in excess of five percent of the annual contract volume (Seasonal Overrun Monthly Volume) will be subject to Seasonal Overrun Charges in place of both the Delivery and Gas Supply Load Balancing Charges. The Seasonal Overrun Charge applicable for the months of December and March shall be calculated as 2.0 times the sum of the Gas Supply Load Balancing Charge, Transportation Charge and the maximum Delivery Charge. The Seasonal Overrun Charge applicable for the months of January and February shall be calculated as 5.0 times the sum of the Load Balancing Charge, Transportation Charge and the maximum Delivery Charge.

Seasonal Overrun Charges:

December and March	**22.8956 ¢/m³**
January and February	**57.2390 ¢/m³**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **8.2598 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after April 1, 2010 under Sales Service and Transportation Service. This rate schedule is effective April 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, April 1, 2010 and that indicates as the Board Order, EB-2009-0172, effective January 1, 2010.

RATE NUMBER: **145**	**INTERRUPTIBLE SERVICE**

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service as ordered by the Company exercising its sole discretion. The Company reserves the right to satisfy itself that the customer can accommodate the interruption of gas through either a shutdown of operations or a demonstrated ability and readiness to switch to an alternative fuel source.
Any Applicant for service under this rate schedule must agree to transport a minimum annual volume of 340,000 cubic metres.

CHARACTER OF SERVICE:

In addition to events as specified in the Service Contract including force majeure, service shall be subject to curtailment or discontinuance upon the Company issuing a notice not less than ~~72~~ 16 hours prior to the time at which such curtailment or discontinuance is to commence. An Applicant may, by contract, agree to accept a shorter notice period.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month
	January to December
Monthly Customer Charge	**$122.73**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**8.2300 ¢/m³**
For the first 14,000 m³ per month	**2.8750 ¢/m³**
For the next 28,000 m³ per month	**1.5160 ¢/m³**
For all over 42,000 m³ per month	**0.9570 ¢/m³**
Gas Supply Load Balancing Charge	**0.3639 ¢/m³**
Transportation Charge per cubic metre	**4.6549 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**21.2033 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 16 hours of notice per cubic metre of Mean Daily Volume from December to March	**$**	**0.50 /m³**
~~Rate for 72 hours of notice per cubic metre of Mean Daily Volume from December to March~~	~~**$**~~	~~**0.11 /m³**~~

RATE NUMBER: **145**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the ~~average~~ highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Any material instance of failure to curtail ~~The third instance of such failure~~ in any contract year may result in the Applic forfeiting the right to be served under this rate schedule.

In such case, service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

Any Applicant taking a material volume of Unauthorized Supply Overrun Gas, during a period of ordered curtailment, may forfeit its curtailment credits for the respective winter season, December through March inclusive.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**7.8391 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after April 1, 2010 under Sales Service and Transportation Service. This rate schedule is effective April 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, April 1, 2010 and that indicates as the Board Order, EB-2009-0172, effective January 1, 2010.

RATE NUMBER 170	LARGE INTERRUPTIBLE SERVICE

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas of not less than 30,000 cubic metres and a minimum annual volume of 5,000,000 cubic metres to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service when required by the Company.
The Company reserves the right to satisfy itself that the customer can accommodate the interruption of gas through either a shutdown of operations or a demonstrated ability and readiness to switch to an alternative fuel source.
The Company, exercising its sole discretion, may order interruption of gas service upon not less than four (4) hours notice.

CHARACTER OF SERVICE:

In addition to events as specified in the Service Contract including force majeure, service shall be subject to curtailment or discontinuance upon the Company issuing a notice not less than 4 hours prior to the time at which such curtailment or discontinuance is to commence.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month
	January to December
Monthly Customer Charge	**$278.27**
Delivery Charge	
Per cubic metre of Contract Demand	**4.0900 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.5583 ¢/m³**
For all over 1,000,000 m³ per month	**0.3583 ¢/m³**
Gas Supply Load Balancing Charge	**0.2040 ¢/m³**
Transportation Charge per cubic metre	**4.6549 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**21.0244 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 4 hours of notice per cubic metre of Mean Daily Volume from December to March **$ 1.10 /m³**

RATE NUMBER **170**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the ~~average~~ highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Any material instance of failure to curtail ~~The third instance of such failure~~ in any contract year may result in the Applic forfeiting the right to be served under this rate schedule.

In such case, service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

Any Applicant taking a material volume of Unauthorized Supply Overrun Gas, during a period of ordered curtailment, may forfeit its curtailment credits for the respective winter season, December through March inclusive.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **5.3625 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after April 1, 2010 under Sales Service and Transportation Service. This rate schedule is effective April 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, April 1, 2010 and that indicates as the Board Order, EB-2009-0172, effective January 1, 2010.

RATE NUMBER: **200**	**WHOLESALE SERVICE**

APPLICABILITY:

To any Distributor who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of an annual supply of natural gas to customers outside of the Company's franchise area.

CHARACTER OF SERVICE:

Service shall be continuous (firm), except for events as specified in the Service Contract including force majeure, up to the contracted firm daily demand and subject to curtailment or discontinuance, of demand in excess of the firm contract demand, upon the Company issuing a notice not less than 4 hours prior to the time at which such curtailment or discontinuance is to commence.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	
The monthly customer charge shall be negotiated with the applicant and shall not exceed:	**$2,000.00**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**14.7000 ¢/m³**
Per cubic metre of gas delivered	**1.1667 ¢/m³**
Gas Supply Load Balancing Charge	**0.5236 ¢/m³**
Transportation Charge per cubic metre	**4.6549 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**21.0244 ¢/m³**
Buy/Sell Sales Gas Supply Charge per cubic metre (If applicable)	**21.0020 ¢/m³**

The rates quoted above shall be subject to the Gas Inventory Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". Also, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable to volumes of natural gas purchased from the Company. The volumes purchased shall be the volumes delivered at the Point of Delivery less any volumes, which the Company does not own and are received at the Point of Acceptance for delivery to the Applicant at the Point of Delivery.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 4 hours of notice per cubic metre of Mean Daily Volume from December to March **$ 1.10 /m³**

RATE NUMBER: **200**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the ~~average~~ highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

The third instance of such failure in any contract year may result in the Applicant orfeiting the right to be served under this Rate Schedule. In such case, service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**6.2905 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after April 1, 2010 under Sales Service including Buy/Sell Arrangements and Transportation Service. This rate schedule is effective April 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, April 1, 2010 and that indicates as the Board Order, EB-2009-0172, effective January1, 2010.

RIDER: A	TRANSPORTATION SERVICE RIDER

APPLICABILITY:

This rider is applicable to any Applicant who enters into Gas Transportation Agreement with the Company under any rate other than Rates 125 and 300.

MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:

Fixed Charge	$75.00 per month
Account Charge	$0.21 per month per account

AVERAGE COST OF TRANSPORTATION:

The average cost of transportation effective January 1, 2010:

Point of Acceptance	**Firm Transportation (FT)**
CDA, EDA	4.6549 ¢/m³

TCPL FT CAPACITY TURNBACK:

APPLICABILITY:

To Ontario T-Service and Western T-Service customers who have been or will be assigned TCPL capacity by the Company.

TERMS AND CONDITIONS OF SERVICE:

~~1. The Company will accommodate TCPL FT capacity turnback from customers to the extent that the Company is allowed to turnback FT capacity to TCPL.~~

~~2. The Company will accommodate all TCPL FT capacity turnback requests in a manner that minimizes stranded and other transitional costs. The Company is committed to maintaining the integrity of its distribution system and the sanctity of all contracts.~~

1. The Company will accommodate TCPL FT capacity turnback requests from customers, but only if it can do so in accordance with the following considerations:
   i. The FT capacity to be turned back must be replaced with alternative, contracted firm transportation (primary capacity or assignment) of equivalent quality to the TCPL FT capacity;

   ii. The amount of turnback capacity that Enbridge otherwise may accommodate may be reduced to address the impact of stranded costs, other transitional costs or incremental gas costs resulting from the loss of STS capacity arising from any turnback request; and

   iii. Enbridge must act in a manner that maintains the integrity and reliability of the gas distribution system and that respects the sanctity of contracts.

~~3. The Company may amend any contracts to accommodate a customer's request to turnback capacity.~~

~~4. Notice of TCPL FT turnback capacity will be accepted on Enbridge's Election for Enbridge Firm Transportation Assignment form or other authorized written notice.~~

2. Requests for TCPL FT turnback must be made in writing to the attention of Enbridge's Direct Purchase group.

~~5. The daily contractual right to receive natural gas would still be subject to the delivery, on a firm basis, of the full Mean Daily Volume into the Company's Central Delivery Area (CDA) and/or Eastern Delivery Area (EDA). The delivery area must match the area in which consumption will occur.~~

RIDER:	A

~~6.~~ ~~The proportion of TCPL FT capacity that an eligible customer may request to be turned back each year ("percentage turnback") shall not exceed the proportion of the TCPL capacity that Enbridge is entitled to turn back that year. This percentage turnback will be applied to calculate the customer's turnback capacity limit based on the renewal volume of the direct purchase agreement.~~

~~7.~~ ~~If the Company is unable to accommodate all or a portion of an eligible customer's request to turnback TCPL FT capacity in the month requested by the customer, the Company will indicate the month(s) when such customer request can be fully satisfied and the costs, if any, associated with accommodating this request. The customer may then advise the Company as to whether or not they wish to proceed with the TCPL FT capacity turnback request.~~

~~8.~~ 3. All TCPL FT capacity turnback requests will be treated on an equitable basis.

~~9.~~ ~~Customers may withdraw their original election given they provide notice to the Company a minimum of one week prior to the deadline specified in the TransCanada tariff for FT contract extension.~~

~~10.~~ 4. The percentage turnback of TCPL FT capacity will be applied at the Direct Purchase Agreement level.

~~11.~~ 5. Written notice to turnback capacity must be received by the Company the earlier of:

(a) Sixty days prior to the expiry date of the current contract.

or

(b) A minimum of one week prior to the deadline specified in TransCanada tariff for FT contract extension.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after April 1, 2010. This rate schedule is effective April 1, 2010 and replaces the identically numbered rate schedule that specifies implementation date, April 1, 2010 and that indicates as the Board Order, EB-2009-0172, effective January 1, 2010.

Index of Appendices

No.	Description
Appendix A	Minutes of Consultative Group Meeting on August 13, 2009, including Appendices
Appendix B	Minutes of Consultative Group Meeting on October 16, 2009, including Appendices
Appendix C	Minutes of Consultative Group Meeting on November 20, 2009, including Appendices
Appendix D	Minutes of Consultative Group Meeting on January 21, 2010, including Appendices
Appendix E	Minutes of Consultative Group Meeting on February 25, 2010, including Appendices
Appendix F	Minutes of Consultative Group Meeting on April 8, 2010, including Appendices
Appendix G	Minutes of Consultative Group Meeting on April 30, 2010, including Appendices
Appendix H	Minutes of Consultative Group Meeting on May 17, 2010 (morning session), including Appendices

Meeting Notes

Enbridge Gas Distribution Inc.
Stakeholder Conference 1
On
Firm Upstream Transportation

August 13, 2009
Ontario Energy Board
North Hearing Room
Toronto, Ontario

Prepared By:
Bob Betts, P.Eng.
Regulatory Support Services
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Enbridge Gas Distribution Inc.
Stakeholder Conference 1
On
Firm Upstream Transportation

1. Opening and Introductory Remarks

Presented by Bob Betts, Facilitator

The meeting was called to order at 1:30 p.m. Bob Betts welcomed all those in attendance and solicited the names of any participants that had joined the group over the lunch break.

He indicated that this afternoon session would face a short interruption when Enbridge Gas Distribution Inc. ("Enbridge" or "EGD") finalizes the Process Plan that was the outcome of the morning meeting. Enbridge was planning on distributing it in this session.

After asking for any questions or comments from participants, Bob turned the next portion of the session over to the presenters.

2. Firm Upstream Transportation Decision Overview

Presented by Ian Macpherson, Manager, Direct Purchase
(A copy of the presentation is included as Appendix C)

Ian first presented a summary of the key points in the Board's EB-2008-0219 Decision and Order for Phase 2 issued on July 14, 2009, which have guided his presentation and the structure of this consultation process. They were:

- System reliability requires EGD to plan for sufficient capacity to meet design day requirements;
- System planning need not be reactive to a system failure, but should seek to prevent such a failure
- Concern for reliability was valid and should be addressed now
- The Board sought to balance the interest of EGD and stakeholders by finding common ground for an interim solution
- The Board expects EGD to have a thorough consultation with stakeholders.
- Enbridge shall file a long term resolution with the OEB following consultation with stakeholders in time for the 2010/2011 winter season
- Enbridge shall resume the TCPL FT Capacity Turnback process and will file an application to the Board should any changes be required

Then he summarized the following significant points about the Board's Interim Resolution:

- The Interim Resolution has been included in to the Rate Handbook
- Rate Handbook amendment highlights include:

  - Minimum amount of gas deliveries for the winter period, defined to be from January 1st to March 31st, to be underpinned with Firm Transportation ("FT") and/or Short Term Firm Transportation ("STFT"), i.e. firm transportation
  - Applicant to calculate the minimum amount of gas deliveries via firm transportation as follows;
    - average the level of firm deliveries over the months of January-March for the prior three years;
    - Plus ten percentage points to that average
  - Applicant to provide written confirmation of gas delivery plans using firm transportation for the winter period to Enbridge prior to November 1, 2009 (both volumetric and percentage deliveries represented in the delivery plans).
- He added the Board's finding that the Interim Resolution would remain in effect until a Long Term Resolution was approved and implemented.

3. Interim Resolution Implementation

Presented by Ian Macpherson, Manager, Direct Purchase

Ian now focused on how Enbridge would implement Board's Interim Resolution. The primary components of EGD's Interim Resolution plan are as follows:

1. Applicants will calculate the minimum amount of gas deliveries that are to be underpinned by firm transportation for each OTS-ABC Pool
2. Applicants will populate the Firm Transportation Template (included as the 8th slide in the presentation and otherwise available from Enbridge) for each OTS-ABC Pool
3. Applicant will submit the completed Firm Transportation Template and Officer's Certificate (a copy was included as the 7th slide in the presentation) to firm.transportation.reporting@enbridge.com on a confidential basis for system planning use no later than November 1, 2009
4. Enbridge will incorporate underpinning Firm Transportation into gas supply planning
5. Enbridge will make available any information required by the Board

In response to a question from CCC, Mr. Macpherson confirmed that references on this slide to Firm Transportation refer also to Short Term Firm Transportation ("STFT").

Ian went on to discuss the example calculations included in the Firm Transportation Template, describing the principles applied and derivation of the inputs. This sparked some questions and led into the Q&A period.

4. Review of FAQ's and Other Questions about the Interim Resolution

Presented by Ian Macpherson, Manager, Direct Purchases

4.1. Question: Why is pool-by-pool detail required?

DE requested confirmation that the underpinning requirement is not done on a pool-by-pool basis, but is done on a composite basis. After that was confirmed by Ian, DE asked: Why then is it necessary to report details on a pool-by-pool basis?

Answer:

Ian responded by saying that it will assist EGD to validate information and it also ensures that all parties will use the same calculation process.

4.2. FAQ 1: Does this apply to agents or customers?

FAQ: Does the Firm Upstream Transportation requirements apply to OTS-ABC Agents, Customers, or both?

Answer:

Applicants that have executed “Customer” type direct purchase agreements will be exempt. As a result, only Applicants with “Agent” type direct purchase agreements would be affected.

4.3. Question: Is an Association an “Agent”??

Shell then asked if an Association was considered an Agent?

Answer:

Ian replied saying that if the association has signed a contract that is an agent type contract, then yes, otherwise no. For further clarification, he gave that example: A chain of outlets that has signed an agreement for several of its locations would not be an agent. This requirement applies to Agent Type OTS contract, and not customer type OTS contracts.

4.4. FAQ 2: Are firm purchase agreements considered to underpin firm transportation?

FAQ: If I have a firm agreement to purchase delivered gas in the distribution area with a third party, would my deliveries be considered underpinned by firm transportation?

Answer:

No. Applicants must hold Firm Transportation, and/or Short Term Firm Transportation with TCPL in their own name to qualify as underpinned firm transportation. *[NOTE added by B. Betts: This answer will be reviewed based upon discussions that took place later in the meeting.]*

4.5. FAQ 3: Is it necessary to unwind a portion of past firm purchase agreements to contract for the required Firm Transportation?

FAQ: Over the last 3 years, I have had a firm agreement to purchase delivered gas in the distribution area with a third party. Does that mean I must unwind at least 10% of my deliveries and contract that amount with Firm Transportation or Short Term Firm Transportation with TCPL?

Answer:

Each OTS-ABC Applicant must determine how they will manage their transportation portfolio. But, an incremental 10 percentage points of your deliveries over the average of the last three years must be underpinned by firm transportation.

4.6. FAQ 4: What specific information must I provide to Enbridge?

FAQ: What specific information must I provide to Enbridge?

Answer:

To ensure that information is provided to Enbridge in a consistent manner, we will be distributing a Firm Transportation Template that will be supported by an Officer's Certificate. The template will include pool level information such as Pool ID, Pool MDV, and Underpinned Firm Transportation that will be aggregated to the MSA level (see attached).

4.7. FAQ 5: Do pools terminated in the winter period need to be included?

FAQ: Do I need to include Pools that are terminated during the winter period (for example, a Pool that terminates on January 31, 2010)?

Answer:

Yes. OTS-ABC Pools that will be active during all or any portion of, the period from January 1, 2010 to March 31, 2010 must be included.

4.8. FAQ 6: Will Capacity Turnback be available for November 1, 2009?

FAQ: Will TCPL FT Capacity Turnback be available for November 1, 2009?

Answer:

No. Enbridge cannot facilitate TCPL FT Capacity Turnback at this time without incurring stranded capacity or other transitional costs. TCPL FT Capacity Turnback will be made available as per Rider A of the Rate Handbook. The earliest EGD can reinstate Capacity Turnback will be November 1st, 2010.

4.9. Question: What if a customer renews part way through the winter period?

Shell enquired on the process for a customer whose contract renews on February 1, and particularly one who may not know the MDV for the upcoming contract year.

Answer:

Ian indicated that a customer would have the responsibility of forecasting their demand for the upcoming contract year but that EGD would assist if necessary. The Mean Daily Volume ("MDV") would require a sign-off from the customer. .

4.10. Question: What if an Association cannot satisfy TCPL's credit requirements?

Shell, with a follow-up question by CME, also discussed the issue of credit requirements for an association, in that some associations may not be able to comply with TCPL's credit requirements resulting in a difficult situation to work through.

Answer:

M. Giridhar first acknowledged that STFT is not an assignable service. She then responded directly to the question by outlining two possible scenarios. In the first case, if it was FT that they chose, they could come to EGD for an assignment and EGD would try to accommodate that. Secondly, she described a possible solution which EGD will be considering further, and that is that a company like Shell Energy with available transportation may be able to work out an arrangement with the customer, which could provide the customer with the assurance they need to certify firm transportation to EGD.

Shell added that while that sounds reasonable and flexible, it is contrary to the Answer to FAQ2, on Slide 9. Malini agreed and indicated that EGD needs to think this through, and welcomes further discussion on the idea.

4.11. Question: Can the transportation be acquired by a third party and assigned to the customer?

As a further follow-up, BP enquired if the agent was not able to acquire transport and if the supplier is willing to take on the transport and assigned that capacity to the customer, would that be consider underpinned by FT?

Answer:

Malini Giridhar once again stated that ultimately, the certifying officer of the customer company must be confident that the firm transportation contracted on their behalf by a supplier underpins their firm requirements.

4.12. Question: Is it necessary for a customer to show a signed contract or just state the transportation plans by November 1st?

Is it necessary for a customer to show a signed contract by November 1st or just state the plans to contract for transportation?

Answer:

Ian stated the customer is required to confirm their transportation plan to EGD by November 1st.

4.13. Question: Are customer type OTS-ABC contracts subject to this arrangement?

TCPL asked why are customer type OTS-ABC arrangements not subject to this arrangement, while agent OTS-ABCs are??

Answer:

Ian indicated that the Board's Decision did not expressly stipulate that customer type OTS-ABC contracts were excluded from the Interim Resolution, but since EGD had only asked for agent type OTS-ABCs to be ordered to comply with greater FT, EGD will hold to its original request and apply it only to agent type arrangements.

4.14. Question: Will EGD change the answer to FAQ 2 on Slide 9 to reflect the position it has expressed today?

DE started by asking for confirmation of his understanding that both the Officer's Certificate and the Firm Transportation Template were required to be filed with Enbridge on or before November 1st, but that it was not necessary to have signed FT contracts at that time, Ian Macpherson confirmed those points. Next DE asked about the answer to FAQ 2 on slide 9 which states: "Applicants must hold Firm Transportation, and/or Short Term Firm Transportation with TCPL in their own name to qualify as underpinned firm transportation". His question was: Will EGD be considering changing that, since they have stated here today that as long as the customer can certify that FT underpins their capacities EGD will be satisfied, in other words that the FT could be provided by third parties?

Answer:

Ian responded by saying yes, they will reconsider the answer to FAQ 2.

4.15. Question of clarification regarding Slide 6, Item 1

ECNG asked if it would not be more appropriate to change the statement "Applicants will calculate the minimum amount of gas deliveries that are to be underpinned by firm transportation for each OTS-ABC Pool" appearing as bullet 1 on Slide 6 to read, "Applicants will calculate the minimum amount of gas deliveries that are to be underpinned by firm transportation for each agency type OTS-ABC Pool", based upon today's discussion.

Answer:

Malini Giridhar agreed that clarification would be appropriate.

4.16. Question: Clarification was requested that deliveries would only be expected to be met at the aggregate level, not the pool-by-pool level?

DE asked if EGD would add wording to the Template stating that deliveries would only be expected to be met at the aggregate level, not the pool-by-pool level?

Answer:

Ian thought that the wording was in the package somewhere, but that he would ensure that it was made clear.

4.17. Question: What steps are EGD taking to ensure confidential handling of the data?

DE asked EGD to advise what steps were being taken to ensure confidential treatment of the date submitted by parties?

Answer:

Ian responded by saying that a special, restricted web address had been created to receive the data, which will be accessible by only two people, himself and the Manager, Customer Relationships, and that the data will only be shared with personnel in the gas supply planning group for the sole purpose of gas supply planning, and will not distributed to any other parties.

Malini Giridhar added the clarification that the information may need to be shared with the OEB, but if that became necessary it would be done using either the normal confidential guidelines, or by filing the information at an aggregated level only.

There being no further questions at this stage, Malini Giridhar began to describe the proposed process and timelines for this consultation process.

5. Long Term Resolution Process and Timetable

Presented by Malini Giridhar, Director Energy Supply and Policy
Malini directed the group to Slide 11 of the presentation containing the consultation process and the Long Term Resolution Timetable.

She said that the discussion that she participated in this morning informed her that parties wanted to be involved to a greater degree in the formation of any early concepts by EGD, and that she supported that approach. Malini indicated that she could adjust this proposed consultation plan to mirror the Storage Unbundling plan and timeline agreed to earlier today, even to the point of planning meetings on the same day, as was the case for this meeting.

Bob Betts reminded the group that a consultation process plan for Upstream Transportation did not need to be filed with the OEB, as in the case of the Storage Unbundling Process plan, and that EGD therefore would have the opportunity to change the proposed plan and circulate it to stakeholders, together with other clarifications and modifications to the presentation.

5.1. Question: Will a list of issues be prepared for the workshop participants?

CME asked if workshop participants could expect to receive a list of issues similar to that proposed for the Storage Unbundling review?

Answer:

M. Giridhar replied that EGD would put together a list of issues and circulate it to participants for the stakeholders to comment on and add to.

5.2. Question: Which Rate Classes are to be considered in this review process?

CME indicated that it would be very helpful if all participants could understand how open EGD would be to including consideration of other rate classes in the scope of the review, i.e. is the long term solution to be applied to all customers, or to just OTS-ABC customers?

Answer:

Malini replied that she would like that to be discussed by the entire group at the first session.

5.3. Question: Will the Long Term Resolution be filed in time for the 2010/2011 winter period?

TCPL requested that Enbridge walk through for the FT filing for November 1, 2010, with the thought in mind that some potential outcomes from this consultation may not be able to be implemented as proposed in the Board's decision.

Answer:

Malini noted that depending on the solution, such as a vertical slice solution, more time will be required. That kind of information would be filed with the application, identifying both the solution and the timelines. She reminded participants that the OEB had implemented the Interim Resolution such that it would remain in place until a Long Term Resolution is approved and implemented.

5.4. Question: If consensus cannot be reached on a single resolution, will EGD file options for the Board's consideration?

Shell asked if a consensus could not be reached on a single resolution, will EGD file options for the Board's consideration?

Answer:

Malini indicated that while it is her hope that a consensus can be reached, if that failed to happen EGD is committed to report on the discussions occurring within this consultative and if other options were considered, they would become part of that reporting.

5.5. Question: How will all options be evaluated fully?

DE wanted to ensure that all options including DE's were considered by the consultation process?

Answer:

M. Giridhar indicated that her hope is that all options proposed by the group, would be fully evaluated for benefits and impacts to all stakeholders.

5.6. Question: Has EGD considered hiring an outside party to independently evaluate various options?

DE asked if EGD would be considering hiring an outside party to independently evaluate various options?

Answer:

Malini and Norm Ryckman indicated that has not been considered yet.

5.7. Question: Will Enbridge be outlining rules for Intervenor funding?

CCC asked if EGD would be outlining or clarifying rules about intervenor funding for this process?

Answer:

EGD indicated that it would clarify questions around intervenor funding and would consider including it in the letter going to the Board.

6. Conclusion and Closing

Bob Betts thanked the group for their openness and collaborative approach to this consultation, and indicated that he hopes that future sessions will be as positive and productive.

Norm Ryckman thanked participants on behalf of Enbridge Gas Distribution and expressed EGD's commitment to the consultation process. He added his optimism that this would lead successfully to a positive outcome.

7. Next Steps and Action Items

- Notes from this meeting will be circulated ASAP.
- Revise the consultation process plan and timeline, and FAQ answers to circulate to stakeholders
- Stakeholders will be notified of subsequent consultation sessions.
- Enbridge will notify all participants when a Website is created
- EGD will ensure that the scope of the review as discussed in CME's question 5.2 would be an early item on the Agenda of the first workshop session.
- EDGD will consider other venues for meetings, while recognizing that all parties were quite happy with the OEB's North Hearing for the size of group we had.
- Consider having white boards available for working sessions.

Appendix A: Meeting Agenda August 13, 2009

STAKEHOLDER CONFERENCE

THURSDAY, AUGUST 13, 2009

2300 Yonge Street, 25th Floor, North Hearing Room

AGENDA

FIRM UPSTREAM TRANSPORTATION – 1:30 - 3:00

Decision Overview ………………………………………………	Ian Macpherson
Interim Resolution Implementation …………………………….	Ian Macpherson
Interim Resolution FAQ ……………………………………….	Ian Macpherson
Long Term Resolution Timetable ………………………………	Malini Giridhar
Round-table Discussion ……………………………………….	Bob Betts

Appendix B: Participant Listing

Stakeholders

Attendee	Organization
Bill Thompson	Access Gas
Val Young	AEGENT
Randy Aiken (Telephone)	BOMA
Peter Exall	BP Canada
Julie Girvan	CCC
Vincent DeRose	CME
Andrea Gibbs	Direct Energy
Rick Forester	Direct Energy
Brad Janzen (Telephone)	Direct Energy
Nicole Black (Telephone)	Direct Energy
Marcia Kall	E2 Energy Inc.
Bill Killeen	ECNG
David Macintosh	Energy Probe
Fred Hassan	ERA on behalf of APPrO
Ian Mondrow	IGUA
Jason Stacey	Independent
Frank Brennan	OAPPA
Nola Ruzycki	OESC
Colin Schuch	Ontario Energy Board
Paul Dumaresq	Shell Energy
Paul Kerr	Shell Energy
Judy Wasney	Superior Energy
Susannah Robinson	Superior Energy
Laura Jehn, CGA in place of Rob Finlay	TransAlta
Lisa DeAbreu	TransCanada Pipelines
Murray Ross	TransCanada Pipelines

Enbridge Representatives

Attendee	Position
Norm Ryckman	Director, Regulatory Affairs
Anton Kacicnik	Manager, Rate Research & Design
Robert Bourke	Manager, Regulatory Proceedings
Malini Giridhar	Director, Energy Supply & Policy
Ian Macpherson	Manager, Direct Purchase
Bruce Manwaring	Manager, Contract Compliance
Andrew Welburn	Manager, Contract Relationships
Iftikhar Abbasi (Note Taker)	Manager, Rate Research
Keith Irani (Note Taker)	Manager, Energy Supply Services
Fred Cass	Council (Aird & Berlis)

Other

Bob Betts	Facilitator, Regulatory Support Services

Firm Upstream Transportation

August 13, 2009

Appendix C
Firm Upstream Transportation
Presentation by Ian MacPherson

Agenda

- Decision Overview
- Interim Resolution Implementation
- Interim Resolution FAQ
- Long Term Resolution Timetable

Decision Overview

- EB-2008-0219 Decision and Order for Phase 2 published on July 14, 2009
- The Board agreed that system reliability required EGD to plan for sufficient capacity to meet design day requirements
- The Board agreed that system planning need not be reactive to a system failure but should seek to prevent such a failure
- The Board agreed that the concern for reliability was valid and should be addressed now
- The Board sought to balance the interest of EGD and stakeholders by finding common ground for an interim solution
- The Board expects a thorough consultation with stakeholders

ENBRIDGE

Decision Overview

- Interim resolution included an amendment to the Rate Handbook

- Rate Handbook amendment highlights include:

  – Minimum amount of gas deliveries for the winter period to be underpinned with Firm Transportation and/or Short Term Firm Transportation

  – Applicant to calculate the minimum amount of gas deliveries as follows;
    - average the level of firm deliveries over the months of January-March for the prior three years;
    - Plus ten percentage points to that average

  – Applicant to provide written confirmation of gas delivery plans and firm transportation for the winter period to Enbridge prior to November 1, 2009

ENBRIDGE

Decision Overview

- Enbridge required to notify all OTS-ABC customers of interim Rate Handbook amendment
- Enbridge shall file a long term resolution with the OEB following consultation with stakeholders in time for the 2010/2011 winter season
- Enbridge shall resume the TCPL FT Capacity Turnback process and will file an application to the Board should any changes be required

ENBRIDGE

Interim Resolution Process

1. Applicants will calculate the minimum amount of gas deliveries that are to be underpinned by firm transportation for each OTS-ABC Pool

2. Applicants will populate the Firm Transportation Template (to be provided by Enbridge) for each OTS-ABC Pool

3. Applicant will submit the completed Firm Transportation Template and Officer's Certificate to firm.transportion.reporting@enbridge.com on a confidential basis for system planning use no later than November 1, 2009

4. Enbridge will incorporate underpinning Firm Transportation into gas supply planning

5. Enbridge will make available any information required by the Board

ENBRIDGE

Officer's Certificate

[Customer] (the "**Corporation**")

OFFICER'S CERTIFICATE

TO: Enbridge Gas Distribution Inc. ("**Enbridge**")

RE: Implementation of EB-2008-0219 Decision and Order of the Ontario Energy Board, dated July 14, 2009 (the "**Order**")

I, ●, certify in my capacity as a duly appointed officer of the Corporation, and not in my personal capacity, as follows:

1. I am the duly appointed ● of the Corporation and I am familiar with the Order, and how the Order applies to the Corporation in connection with the Corporation's Gas Delivery Agreement(s) with Enbridge.

2. I have made or caused to be made such examinations or investigations as are, in my opinion, necessary to fully inform myself of the matters addressed in this Certificate and to make the statements below, and I have furnished this Certificate and acknowledgement with the intent that it may be relied upon by Enbridge.

3. As of the date of this Certificate, set out below, the Corporation has verified and accurately set out in Schedule "A" attached hereto, all figures, calculations, and other information necessary to determine:

(a) the annual percentage of firm upstream transportation held in the name of the Corporation ("**Firm Transport**") that underpinned gas deliveries by the Corporation to Enbridge for each of the immediate past three (3) winter periods;

(b) and taking the average of these three years' percentages and adding ten percentage points to that average, the minimum percentage and volume of gas contracted with Enbridge for delivery in the 2009/2010 winter season that must be underpinned by Firm Transport, in accordance with the Order.

DATED this ________ day of ____________, 200__.

Name:
Title:

Firm Transportation Template

		2007 Winter Period[1]		2008 Winter Period[1]		2009 Winter Period[1]		Average Winter Period[1]		2010 Winter Period[1]	
MSA ID	Pool ID	MDV (m3)	Underpinned FT/STFT[2] (m3)	MDV (m3)	Underpinned FT/STFT[2] (m3)	MDV (m3)	Underpinned FT/STFT[2] (m3)	MDV (m3)	Underpinned FT/STFT[2] (m3)	Forecasted MDV (m3)	Forecasted Underpinned FT/STFT[2] (m3)
123	111	100	20	100	20	100	20	100	20	50	15
123	222			200	200	300	300	250	250	400	400
123	333					1,100	230	1,100	230	1,000	0
123	444									3,000	2,085
123	555	550	0	550	0	550	0	550	0	550	0
Total Volume								2,000	500	5,000	2,500
Total Percent[3]									25.0%		50.0%
Minimum Percent[4]											35.0%

Notes:

1. Winter Period includes January 1 through to March 31.
2. TransCanada Pipelines Firm Transportation ("FT") and/or Short Term Firm Transportation ("STFT") dedicated to the respective Pool ID.
3. Total Percent based on Underpinned FT/STFT divided by MDV. Applicable to the Average Winter Period and the 2010 Winter Period.
4. Minimum Percent based on Total Percent for the Average Winter Period plus an incremental 10%.
5. Shaded area include lables and formulas that should not be manually adjusted.

Interim Resolution FAQ

1. Does the Firm Upstream Transportation requirements apply to OTS-ABC Agents, Customers, or both?
   – Applicants that have executed “Customer” type direct purchase agreements will be exempt. As a result, only Applicants with “Agent” type direct purchase agreements would be affected.

2. If I have a firm agreement to purchase delivered gas in the distribution area with a third party, would my deliveries be considered underpinned by firm transportation?
   – No. Applicants must hold Firm Transportation, and/or Short Term Firm Transportation with TCPL in their own name to qualify as underpinned firm transportation.

3. Over the last 3 years, I have had a firm agreement to purchase delivered gas in the distribution area with a third party. Does that mean I must unwind at least 10% of my deliveries and contract that amount with Firm Transportation or Short Term Firm Transportation with TCPL?
   – Each OTS-ABC Applicant must determine how they will manage their transportation portfolio. But, an incremental 10 percentage points of your deliveries over the average of the last three years must be underpinned by firm transportation.

Interim Resolution FAQ

4. What specific information must I provide to Enbridge?
   – To ensure that information is provided to Enbridge in a consistent manner, we will be distributing a Firm Transportation Template that will be supported by an Officer's Certificate. The template will include pool level information such as Pool ID, Pool MDV, and Underpinned Firm Transportation that will be aggregated to the MSA level (see attached).

5. Do I need to include Pools that are terminated during the winter period (for example, a Pool that terminates on January 31, 2010)?
   – Yes. OTS-ABC Pools that will be active during all, or any portion of, the period from January 1, 2010 to March 31, 2010 must be included.

6. Will TCPL FT Capacity Turnback be available for November 1, 2009?
   – No. Enbridge can not facilitate TCPL FT Capacity Turnback at this time without incurring stranded capacity or other transitional costs. TCPL FT Capacity Turnback will be made available as per Rider A of the Rate Handbook.

ENBRIDGE

Long Term Resolution Timetable

Action	Task	Participants	Timeline
Consult	Determine process and timelines for long term resolution	EGD/Marketers/ Stakeholders	Aug 13, 2009
Develop	Develop and analyze service options and impacts (consultations as required)	EGD	Q4 - 2009
Consult	Consult and evaluate impact of services	EGD/Marketers/ Stakeholders	Q1 - 2010
Resolution	Finalize and file proposal	EGD/Marketers/ Stakeholders	Q2 - 2010

Appendix C
Firm Upstream Transportation
Presentation by Ian MacPherson

Meeting Notes

Enbridge Gas Distribution Inc.
Stakeholder Conference 2
On
Firm Transportation

October 16, 2009
Ontario Energy Board
North Hearing Room
Toronto, Ontario

Prepared By:
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Table of Contents

Enbridge Gas Distribution Inc.
Stakeholder Conference 2
On
Firm Transportation

1. Opening and Introductory Remarks

Presented by Bob Betts, Facilitator

The meeting was called to order at 1:00 p.m. Bob Betts welcomed all those in attendance and asked for the names of any participants that had joined the group over the lunch break.

He then took a moment to recap activities and events that had occurred since August 13, 2009, the date of Conference 1. The group was reminded of the presentation reviewing the Board's EB-2008-0219 decision which is the genesis of this conference and the presentation outlining the implementation plan for the Board's Interim Resolution. Bob also reminded stakeholders of the agreement that was reached on a consultation process plan that will be used to guide this process.

In the time since the August 13th conference, several steps have been accomplished:

- The agreed upon plan – Long Term Solution Timetable was finalized and distributed to stakeholders and the Board;
- The OEB accepted the proposal for stakeholder funding;
- Enbridge's Interim Resolution implementation plan was modified to reflect input from stakeholders;
- The Information Template and Officer's Certificate have been modified and finalized to reflect stakeholder input, and have since been distributed to affected customers.

He pointed out that Ian Macpherson was in attendance once again to respond to any additional questions regarding Interim Resolution implementation; but no further questions arose from stakeholders.

Bob then reminded parties of the primary objectives of this Firm Transportation Conference 2, which were:

1. Present and discuss alternative approaches to firm transportation
2. Finalize the list of Alternatives, and where possible associated issues for guidance to the Working Committee; and
3. Select the stakeholders who will act as members of the Firm Transportation Working Committee.

After asking for any questions or comments from participants, Bob turned the next portion of the session over to the Enbridge presenter, Malini Giridhar.

Prepared by Regulatory Support Services
(Div of R. J. Betts Enterprises Ltd.)

Aegent comment on process:

Before commencing the presentation, Aegent asked for the opportunity to make a general comment about process, based upon the observation that the objectives for the meeting today focused primarily on alternatives.

Aegent suggested that a first step should be to develop a definition of the issues to be addressed, before the Working Group begins an analysis of the options. It was felt that the Board's Decision would be a good starting point for the determination of issues. That would ensure that the options were weighed in light of the issues to be addressed.

Enbridge agreed and indicated that they assumed that would be the first thing the Working Group would address.

2. Enbridge Update and Presentation of Alternate Solutions and Issues – Malini Giridhar, Director, Energy Supply & Policy

(A copy of the presentation is included as Appendix C)

Malini started by listing the three Options that have been identified by Enbridge, which were circulated prior to this meeting:

1. Vertical slice;
2. Interim Solution (Modified);
3. Backstopping service.

Her slides included a listing of Advantages and Issues associated with each of the three options.

The Description, Advantages and Issues associated with each of these Options are contained on slides 8, 9 and 10 of Appendix C and will not be repeated in these notes. Instead the following captures questions, answers and comments that resulted from the presentation.

Questions, Answers and Comments

Slide 8 – Vertical Slice

- The 3rd bullet point under Advantages – Vertical Slice drew a question from IGUA about the meaning of the phrase "optimize transport". Malini responded by saying that customers taking an assignment of transport receive rights to optimize the use. The assignee has the ability to use the features that are associated with the assigned transport.

- DE asked for clarification on the 2nd bullet point under Description, asking if Enbridge wanted firm contracts for long haul up to 100%, but Malini indicated that it would be proportional for practical reasons, and would be something less than 100%. She gave the example that if they are at 95% long haul for the firm market, then they would apply that percentage to the MDV.

- APPro asked if Vertical Slice would apply to new rate 125 customers, Enbridge answered, “No”.

- OAPPA questioned bullet point 1 under Description, asking if it referred to additional FT, Enbridge replied yes. The question went on to ask whether other paths would be considered, and Enbridge indicated that this concept is indifferent to the source. This applies to other paths, including evolving supply basins.

- BP asked if system reliability is better now as a result of full storage, additional pipelines capacities, and recent open seasons. Enbridge indicated that apart from the question of “where” it is, and who has the contractual rights, these additional capacities would improve reliability. She added that detail like this, is more appropriately considered by the Working Committee.

- OESC asked about bullet 1, under Descriptions and Advantages, and what would happen to a marketer who has always had transport for themselves. Enbridge indicated that this should be considered under the issue of “Grandfathering”.

- DE asked about Enbridge’s earlier answer to APPro’s question and if Enbridge could describe how Rate 125 customers are treated now. Enbridge said that unbundled distribution service customers on Rates 125 and 300 are not required to demonstrate Firm transport, but that Enbridge has a right to terminate service to (i.e. shut off) those customers, if they fail to comply with the provisions of the rate schedule, including the provisions of the limited load balancing service. DE asked if that has happen, and Enbridge said it has not happened to date.

Slide 9 – Interim Solution (Modified)

- IGUA asked about the specific mention of “Empress” in the 2nd bullet under Description and if it would be more appropriate to use the phrase “supply basin”. Enbridge said that “supply basin” would be a more appropriate phrase in that bullet.

- DE offered another solution coming from this discussion that building additional short term capacity could represent another solution for the Working Committee to consider.

Slide 10 – Backstopping Service

- In response to a question from BP, Enbridge indicated that the Back-stopping would be contractual in nature including the use of storage, transport, and peaking supplies. BP asked that the Working Committee consider also other forms of Back Stopping.

Discussion of other Solutions

- IGUA offered another option being some form of expanded curtailment options, and said that this and other solutions should be considered by the Working Committee.

3. Discussion and Finalization of the Alternate Solutions and Issues to be considered by the Working Group - Bob Betts, Facilitator

Bob Betts focused stakeholders on the next task to consider the three solutions proposed by Enbridge and the one proposed by Direct Energy in the morning session, and to add any additional ones that parties could identify. He indicated also that this step, to the extent possible, should consider the issues associated with every solution.

DE clarified that the solution they proposed earlier was basically to adopt the Board's Interim Resolution without modification.

After some discussion the following list of solutions was produced:

Option 1: Vertical Slice

Option 2: Interim Solution (Modified)

Option 3: Backstopping Service

Option 4: The Board's Interim Solution

Option 5: Expanded Curtailment systems

All parties agreed that the Working Committee would have the flexibility to consider additional options as their analysis goes forward.

There was considerable discussion about whether or not the current arrangements (i.e. those existing today, prior to the implementation of the Board's Interim Resolution), should be evaluated as an option.

There were several concerns raised about that including: Enbridge's position that the current arrangements are not satisfactory; the Board decision already ordered an Interim Resolution to change the existing arrangements; and forcing the Working Committee to consider that would be like asking them to rehear the matter as it was decided by the Board.

IGUA suggested that the best way to deal with the controversy over whether any change is needed is to ask all parties to accept, that for the purpose of this working committee, the notion that the Board has already recognized the Enbridge concern about decontracting of transportation, and take the Interim Resolution as a starting point. Ultimately this will lead to a proposal by Enbridge to the Board, and parties can work this way on a without prejudice basis, thereby allowing parties to argue any position they choose before the Board.

This discussion resulted with no parties arguing that the current arrangements, unchanged, should be an option for consideration by the Working Committee.

IGUA offered their assessment that the Board had recognized three factors that ultimately led to their concern and their decision to create an Interim Resolution, those three points were:

- The constraint in short haul transportation;
- Enbridge's limited ability to curtail customers; and
- The continuing decontracting of marketers on TCPL.

IGUA recommended that the working group should adopt these as a starting position.

With respect to the issues associated with the alternate solutions, Bob suggested that the stakeholders accept the issues as presented on Enbridge's slides 8, 9 and 10, and allow the Working Committee to consider the issues associated with the other proposed alternatives.

The group accepted that suggestion.

4. Selection of the "Working Group" members – Stakeholders

The final task was to finalize the membership of the Working Committees for both the Storage Unbundling and the Firm Transportation matters.

A list was placed on the Board that represented the recommendations coming out of the Storage Unbundling session in the morning. It was as follows:

CME
IGUA
Union Gas
TCPL
Shell
Aegent
CCC/VECC
Direct Energy
Enbridge

CCC indicated their willingness to participate and said they would contact VECC to reach an agreement on which of the two would participate.

Aegent and Shell indicated their preference to sit on the Firm Transportation Committee, and not the Storage Unbundling Committee. All others on the list were willing to attend both.

All parties present were asked if anyone else would like to be included on the membership lists, and there was no indication of further interest.

It was suggested that by holding the Firm Transportation working committee meeting first followed by the Storage Unbundling meeting, the two parties only interested in Firm Transportation could leave before the Storage Unbundling meeting began.

With that suggestion, the group settled upon the following makeup for the two Working Committees:

Stakeholder Member	Firm Transportation	Storage Unbundling
CME	√	√
IGUA	√	√
Union Gas	√	√
TCPL	√	√
Shell Energy	√	
Aegent	√	
CCC/VECC	√	√
Direct Energy	√	√
Enbridge	√	√

5. Next Steps and Action Items

- Notes from this meeting will be circulated ASAP.
- Stakeholders will be notified of subsequent consultation sessions.
- For the Working Group:
    - From the August 13th Notes: - EGD will ensure that the scope of the review as discussed in CME's question 5.2 (of the Aug 13th Notes) would be an early item on the Agenda of the first workshop session.
    - From this meeting, the working group needs to first define the issues to be addressed, thus allowing options to be measured against their effectiveness at addressing those issues.
    - The working group needs to determine the issues associated with the added optional solutions.

Adjourn

Bob Betts thanked all parties for their participation and wished everyone a safe trip home.

Appendix A: Meeting Agenda October 16, 2009

Stakeholder Conference 2 on Firm Upstream Transportation
AGENDA
October 16, 2009   (1:30 PM – 4:30 PM)
North Hearing Room, Ontario Energy Board

1:30-1:45 pm **Opening Remarks -** Bob Betts, Facilitator

- Welcome and Housekeeping Items
- Introductions of new arrivals following the morning session
- Review of Previous Meeting, August 13, 2009
- Activities since August 13, 2009
- Objectives and plan for this meeting

1:45 – 2:15 pm **Enbridge Update and Presentation of Alternate Solutions and Issues –** Malini Giridhar, Director, Energy Supply & Policy and Ian Macpherson, Manger, Direct Purchase

- New information and updates for the conference
- Review of proposed solutions and issues proposed by Enbridge

2:15 – 2:45 pm **Stakeholder Presentation of Alternate Solutions and Issues to be considered by the Working Group –** Presenters to be Determined

- Stakeholders present their proposals for alternate Solutions and associated Issues to guide the Working Group activities

2:45 – 3:00 pm **Break**

3:00 – 4:15 pm **Discussion and Finalization of the Alternate Solutions and Issues to be considered by the Working Group -** Bob Betts, Facilitator

- Enbridge and stakeholder discussion of proposed list of possible Solutions and associated Issues to guide the Working Group activities

4:15 – 4:30 pm **Selection of the "Working Group" members -** Stakeholders

- Stakeholders select members for the working group
- Bob Betts, can facilitate, if stakeholders wish

4:30 pm **Adjourn**

Appendix B: Participant Listing

Stakeholders

Attendee	Organization
Val Young	AEGENT
Randy Aiken (Telephone)	BOMA
Peter Exall	BP Canada
Julie Girvan	CCC
Vincent DeRose	CME
Rick Forester	Direct Energy
Tim Ray	Direct Energy
Nicole Black (Telephone)	Direct Energy
Bill Killeen	ECNG
David Macintosh	Energy Probe
John Wolnik	ERA on behalf of APPrO
Ian Mondrow	IGUA
Jason Stacey	Independent
Frank Brennan	OAPPA
Nola Ruzycki	OESC
Colin Schuch	Ontario Energy Board
Lawri Gluck	Ontario Energy Board
Jay Shepherd	SEC
Paul Dumaresq	Shell Energy
Judy Wasney	Superior Energy
Susannah Robinson	Superior Energy
Lisa DeAbreu	TCPL
Don Newbury	Union Gas
Chris Ripley	Union Gas

Enbridge Representatives

Attendee	Position
Malini Giridhar	Director, Energy Supply & Policy
Norm Ryckman	Director, Regulatory Affairs
Anton Kacicnik	Manager, Rate Research & Design
Robert Bourke	Manager, Regulatory Proceedings
Ian Macpherson	Manager, Direct Purchase
Bruce Manwaring	Manager, Contract Compliance
Andrew Welburn	Manager, Contract Relationships
Iftikhar Abbasi (Note Taker)	Manager, Rate Research
Keith Irani (Note Taker)	Manager, Energy Supply Services
Himli Muhammad	Manager, Energy Forecasting
Vivian Krauchek	Manager, Gas Supply & Asset Optimization
Michel Levac	Manager, Gas Supply Projects
Fred Cass	Counsel (Aird & Berlis)

Other

Bob Betts	Facilitator, Regulatory Support Services

Appendix C: Firm Upstream Transportation Presentation by Malini Giridhar

Firm Transportation

Stakeholders Conference 2

October 16, 2009

INTRODUCTION
Bob Betts, Facilitator

- Introductions
- Housekeeping Items
- Recap of previous activities
- Objectives for this Firm Transportation Conference 2
- Questions

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Recap of Previous Activities

- August 13th Conference 1
  - Review of OEB EB-2008-0219 Decision on Firm Transportation
  - Review of Implementation Plan for the OEB Interim Resolution
  - Agreement on the consultation process plan
- The OEB accepted Stakeholder Funding
- Prepared and circulated the "Long Term Solution Timetable" – The plan
- Revised and distributed the Firm Transportation Information Template and the Officer's Certificate

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Objectives for Firm Transportation Conference 2

- Present and discuss alternate solutions
- Provide guidance to the working committee
- Select stakeholders to participate in the Firm Transportation Working Committee

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Questions?

Questions or comments?

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Firm Upstream Transportation Stakeholders Meeting
October 16, 2009

Malini Giridhar

Options Considered by EGD

1. Vertical slice

2. Interim solution

3. Backstopping service

Option 1: Vertical Slice

Description	Advantages	Issues
▪ EGD contracts for FT to the franchise on alternate transportation paths. ▪ Contracted capacity is based on mean daily volume (MDV) requirement for EGD sales and direct purchase customers. ▪ DP market assigned proportional capacity in relation to MDV. ▪ All customers deliver a fixed percentage of MDV to the franchise delivery areas and to Dawn (for transportation paths routed through Dawn). ▪ EGD retains and manages Dawn CDA and EDA transport on behalf of all customers.	▪ EGD as system operator, plans, contracts and allocates capacity to DP market. ▪ DP market not constrained by upstream pipeline credit requirements. ▪ DP market able to optimize transport. ▪ Identical transport portfolios for sales and DP customers resulting in level playing field. ▪ Monthly MDV re-establishment and monthly allocation of capacity. ▪ System reliability.	▪ Vertical slice for all firm customers vs. sales service customers. ▪ EGD assumes contract and credit risk. ▪ Grandfathering existing DP arrangements. ▪ Turn back policy. ▪ Integrated operation of CDA and EDA. ▪ Increased administrative costs (IT, FTE).

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Option 2: Interim Solution (Modified)

Description	Advantages	Issues
▪ EGD contracts for FT to the franchise for sales customers only. ▪ DP market demonstrates firm transportation (FT/STFT) contracts from Empress based on MDV requirement, at a minimum for the period December – March.	▪ Addresses system reliability in the winter. ▪ DP market able to optimize transportation costs.	▪ Assured availability of STFT on TCPL every year. ▪ Barriers to contracting for DP market (meeting pipeline credit requirements). ▪ Grandfathering existing DP arrangements. ▪ Diversity of gas supply in the longer term. - Long term contractual obligations required to develop capacity. ▪ Administrative costs of determining firm transportation requirements and the demonstration of firm transportation allocations.

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Option 3 – Backstopping Service

Description	Advantages	Issues
▪ EGD contracts for FT to the franchise on alternate transportation paths for sales customers. ▪ EGD provides backstopping service to DP market to ensure against failure to deliver. ▪ EGD contracts for contingency transport and storage to provide service.	▪ DP market not required to demonstrate firm transport. ▪ EGD maintains system reliability utilizing contingency arrangements.	▪ Determining contingency requirements, transport and storage and peaking. ▪ EGD will require firm short-notice transport and storage with reservation of capacity to respond to failure to deliver. ▪ Trade-off between duplication of capacity vs. adequacy of contingency arrangements. ▪ Lead time to develop short haul contingency transport. ▪ Cost allocation of backstopping service to DP market. ▪ Diversity of gas supply in the longer term.

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Direct Energy Proposal and Others

Working Committee

Guidance

- Items to be Considered by the Working Committee.

Selection and structure

- 5 stakeholders with delegated authority.

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Adjourn the Firm Transportation Conference 2

Adjourn

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Appendix D: List of Options and Issues for Firm Transportation

Option 1	Issues	
Vertical Slice	Vertical slice for all firm customers vs. sales service customers.	
	EGD assumes contract and credit risk.	
	Grandfathering existing DP arrangements.	
	Turn back policy.	
	Integrated operation of CDA and EDA.	
	Increased administrative costs (IT, FTE).	

Option 2	Issues	
Interim Resolution (Modified)	Assured availability of STFT on TCPL every year.	
	Barriers to contracting for DP market (meeting pipeline credit requirements).	
	Grandfathering existing DP arrangements.	
	Diversity of gas supply in the longer term. - Long term contractual obligations required to develop capacity.	
	Administrative costs of determining firm transportation requirements & the demonstration of FT allocations.	

<u>Option 3</u>	<u>Issues</u>	
Backstopping Service	Determining contingency requirements, transport and storage and peaking.	
	EGD will require firm short-notice transport and storage with reservation of capacity to respond to failure to deliver.	
	Trade-off between duplication of capacity vs. adequacy of contingency arrangements.	
	Lead time to develop short haul contingency transport.	
	Cost allocation of backstopping service to DP market.	
	Diversity of gas supply in the longer term.	

<u>Option 4</u>	<u>Issues</u>	
Board's Interim Solution		

<u>Option 5</u>	<u>Issues</u>	
Expanded Curtailment		

<u>Option 6</u>	<u>Issues</u>	

Appendix E: Members of the Firm Transportation Working Committee

Committee Member	Organization
Val Young	AEGENT
Julie Girvan/Roger Higgins	CCC/VECC
Vincent DeRose	CME
Ian Mondrow	IGUA
Lisa DeAbreu	TCPL
Paul Dumaresq	Shell Energy
Chris Ripley	Union Gas
Rick Forester	Direct Energy
Malini Giridhar, et al	EGD

Colin Schuch	Ontario Energy Board

Working Committee Notes

Enbridge Gas Distribution Inc.
Working Committee Meeting 1
On
System Reliability

(Name Change Explained on Page 2)

November 20, 2009
Spruce Room
Enbridge Gas Distribution
Consumers Road
Toronto, Ontario

Prepared By:
Bob Betts, P.Eng.
Regulatory Support Services
(Division of R.J. Betts Enterprises Ltd.)
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Cambridge, ON
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(519) 249-0256

Putting the Pieces Together

Table of Contents

Enbridge Gas Distribution Inc.
Working Committee Meeting 1
On
System Reliability

1. Opening and Introductory Remarks

Presented by Bob Betts, Facilitator

The meeting was called to order at 9:00 a.m. Bob Betts welcomed all those in attendance.

He acknowledged that all but one of the parties had been present at previous meetings and that introductions around the room were not necessary at this time. The exception was Roger Higgins who had not attended previous meeting and Bob invited Roger to explain to all participants his role here and who he was representing.

Roger explained that VECC and CCC had agreed to work together on this consultation process and share the duties. He said they had agreed to divide the responsibilities and share the information, but that Julie Girvan would be primarily responsible for Firm Transportation and that he would be primarily responsible for Storage Unbundling. On this particular day, Julie could not attend and he would be representing CCC in the morning session on Firm Transportation and VECC in the afternoon meeting on Storage Unbundling.

Bob then took a moment to recap activities and the primary discussion areas from the October 16th meeting. He reminded everyone that Enbridge had presented the 3 options that they felt should be evaluated for firm transportation and the issues that were associated with those options. He indicated that stakeholders at that meeting had come up with 2 additional options, but had left the identification of issues associated with those two options to this working committee to develop.

He reminded the committee that all parties, including Enbridge had agreed that the working committee should be free to add additional options if they identify any, or to consider the 5 listed options in any way they chose.

Bob briefly described the goals for this meeting. He said that there would first be a review to ensure that there is a common level of understanding of the Firm Transportation issue and the associated options, and that the review will include an opportunity to add to or comment on the options and associated issues. Enbridge will be providing new data and information about the options, but added that another important goal was to have all parties consider what additional data or information would be helpful to them, as they go forward with their review and analysis.

Prepared by Regulatory Support Services
(Div of R. J. Betts Enterprises Ltd.)

1.1. Committee Name Changes

Shell asked for the opportunity to make two initial comments and started by suggesting that the committee be renamed to the System Reliability Working Committee, to better represent the primary issue. He indicated that while Firm Transportation is an important consideration, system reliability is the over-arching issue. Enbridge agreed with the name and there were no disagreeing parties.

On a similar note, but relating to the Storage Unbundling Committee, Direct Energy suggested that the matter goes beyond Storage Unbundling and that the committee's name should be changed to the Unbundling working committee.

Enbridge agreed in part, but indicated that they would prefer the name Mass Market Unbundling Committee, and Direct Energy agreed.

All other parties present agreed with both names changes.

Shell's second comment was that they were pleased that the System Reliability and Mass Market Unbundling issues had been kept separate at this time.

Frank Brennan asked to ensure that all parties recognized that he was present representing AEGENT, not OAPPA as he had in the earlier stakeholder sessions.

2. Firm Transportation Working Committee Process – Malini Giridhar, Director, Energy Supply & Policy

(Slides 3 and 4 of the Presentation included in Appendix C)

Malini explained her desire to start off the first day of the working committee with a common understanding of the committee's role, responsibilities and rules.

Working Committee Role (paraphrased from the Board's decision):

- To propose various options for long term resolutions of the system reliability issue for presentation to the larger stakeholder group, and eventually to the OEB.

Responsibilities:

- To be objective and cooperative
- To evaluate impacts on all stakeholders as specified in the Board's decision
- To make reasonable efforts to reach consensus
- Where disagreements cannot be resolved, to clearly define the areas of and reasons for the disagreement.

Working Committee Rules:

- To attend all meetings in person, unless impossible or impractical
- To read and prepare in advance of each meeting to maximize efficiency
- To be open minded in considering various options being reviewed
- In the absence of a consensus, committee members will be free to take whatever positions they choose before the OEB

The roles, responsibilities and rules were received without comment and Malini turned the meeting over to Keith Irani.

3. Upstream Firm Transportation Working Committee – Keith Irani, Manager, Energy Supply Services

(Keith's Presentation starts at Page 5 in Appendix C)

Keith introduced himself and his role at Enbridge.

He pointed out the there were a couple of minor changes to the presentation that was originally circulated but that the packages handed out in this meeting reflect the changes.

One of the changes was with sequencing of the slides 13 and 14. Keith felt that the information flowed best by discussing the "Direct Purchase Large Volume Customer – Delivery Volumes" before the "Comparison of System Operator Functions and Responsibilities". These now appear in the presentation as Slides 13 and 14 respectively. The other change was cosmetic only.

Keith's first slides 6, 7 and 8 reviewed the Board's decision that led to this meeting and the Interim Resolution.

These slides were helpful at generating some very important, fundamental discussions about how members felt the committee should proceed with their task.

3.1. Discussion about the Reliability Issue/Problem Fundamentals

First AEGENT talked about the evolution of the system reliability issue before the Board. He pointed out that the starting point was the status quo. After the application by the Enbridge, the Board made a decision as AEGENT put it, "That there is a reliability issue". That led to the Board issuing an "Interim Resolution" and directing that this group come up with a long term solution.

To undertake this task properly, AEGENT stated that the committee should start from the Board's decision and recognition that there is a reliability problem. That the starting point should not be the Interim Resolution because that might eliminate many other solutions to the reliability issue.

IGUA then made a comment about what they felt would be necessary to properly approach this issue. They felt that they need some form of empirical data to assist in illustrating the existence and the magnitude of the reliability problem as it is today. IGUA felt that might start with some evaluation of what is available on peak days to assist Enbridge with its reliability problem. IGUA stated that this was not an attempt to re-litigate the issue, but only to define the problem to be resolved.

CCC added that unlike the electricity sector there are no current ways of measuring system reliability for natural gas distributors. AEGENT agreed that this was necessary to define the problem to be solved and also to measure the effectiveness of any solutions. Shell agreed with the foregoing comments.

Enbridge stated that the issue is that they are held accountable for reliability of supply to their franchise area, but have lost control over deliveries by direct shippers into that system to underpin the demand.

While that issue was generally recognized by the group, IGUA and others said they still needed to understand the nature of the problem by knowing what other means were available to Enbridge to make up a shortfall in deliveries on a peak day. If there were no other means of making up a shortfall, then that would illustrate the problem and ideally quantify the magnitude of the problem.

Enbridge supported this approach and added that as long as they are held accountable for system reliability, if a potential shortfall is identified, then this committee must either identify ways that the shortfall can be avoided, or alternatively develop a plan for shedding load, that could go right down to the residential customer.

IGUA agreed, but added that we need to quantify those potential shortfalls, as well as what quantities are available from various other means to address that problem. Enbridge added that much of that information will have to come from TCPL.

TCPL provided some input on how difficult it is to provide meaningful information about potential available capacities, because by definition there is no excess capacity.

Shell provided their view that Enbridge's concern breaks down to one of supply not showing up on a peak day.

Enbridge agreed that supply not showing up was a major concern, but went further explaining their position by stating that right now they are held accountable for maintaining reliability in peak days by contracting for firm supply and transport on those peaks days. If the Board decided to change that paradigm to one of designing for the probability of shortfalls, and therefore acknowledging the risk of supply curtailment, then the problem shifts to one of developing a plan for load shedding, and then a plan to address the distribution costs and customer issues associated with widespread outages.

Enbridge indicated that they had an idea of what the group was looking for in terms of data, and said that much of it exists in evidence in previous hearings, and that they would try to bring additional data to the next meeting.

IGUA added that they wanted more than that which has been on the record to date. IGUA explained that they wanted to understand what capacity could reasonably be expected to be available in the system for use in a shortfall scenario, along with an estimate of the probability that that capacity would be available on the peak day. If the OEB was willing to accept the capacity number, along with the probability of it being there or not being there when needed, then that amount could be subtracted the amount of firm capacity being contracted for.

Parties looked to TCPL to provide this kind of date. Enbridge also asked TCPL to try including an analysis of the risks associated with mechanical breakdowns, like compressor failures, in peak load conditions. Enbridge felt that needed to be factored into the analysis of potential capacity and probability of that capacity being available in the peak load scenario,

Direct reiterated CCC's point about the need to define system reliability for gas utilities, whether that is by station pressures or capacity coming in, because that would allow measurement and tracking, and better future planning.

TCPL and Enbridge indicated that they would make an effort to provide the information that has been asked for. TCPL indicated that they were still uncertain about what was required. In basic terms, under peak load conditions, there is no capacity available except on the main line and that uncommitted capacity would go to the first bidder. For example it could go to Wisconsin, other northwestern states and not be available to Enbridge customers.

IGUA and others suggested that if it is very difficult to predict available capacity that at the very least TCPL could describe a worst case scenario. That could be based on the highest degree day that would have to be experienced in multiple locations along the pipeline to completely consume the capacity of the pipeline. That estimate of degree days would qualitatively define how probable that event would be.

TCPL indicated that they did not know if they could do that, but they would try.

IGUA indicated that even a TCPL assessment of the probability of a shortfall in supply in the Enbridge franchise would be helpful. IGUA stated that if the committee has to go to the OEB saying that there is absolutely no way of assessing the risk of whether capacity would be available to Enbridge on a peak day, except by means of contracting for firm capacity, then that would simply require a leap of faith in concluding that a problem exists, thus forcing the need for firm contracts and curtailment. That would be a different and unfortunate scenario versus describing to the Board the kind of circumstances that could create such an event and the probability of that happening.

AEGENT presented an idea of using the maximum flow or pipeline capacity at all major discharge points on the mainline, add in peak day draw for Enbridge and Union, and then add in projection of potential mechanical failure to determine how much, if any additional capacity would exist in the pipeline.

IGUA felt that this would be very helpful in illustrating a system reliability problem, particularly with the addition of a map showing all the points of interest and a prediction of the probability of such an event.

This was later described as the "Maximum Constraint Scenario", and TCPL indicated that they would try to do the analysis.

Enbridge added that transmission is clearly where the system reliability issue is focused because Enbridge's low-pressure distribution could not alleviate a shortfall situation utilizing capacity at Parkway.

Everyone agreed that regardless of what that shows, there remains a question about how that scenario would change in the future.

Bob Betts asked if Enbridge and TCPL could provide all of that requested information well in advance of the next meeting to allow parties to indicate if there was something else that could be added to fulfill the request.

Keith continued with the presentation restarting at bullet point 3 on Slide 6 reviewing the Board's Decision.

On Slide 7, Keith clarified Enbridge's interpretation of the Board's Interim Resolution decision that the shippers' commitment to firm transport would increase by 10% per year, every year until a long term resolution was achieved. Direct Energy indicated that they had a different interpretation of the Board's expectations that the shippers' commitment suggesting that the decision to imply an increase every year. All committee members agreed to proceed with the task based upon Enbridge's interpretation, acknowledging that this would not prevent them for arguing the point at a later time.

Keith returned to slide 8 of his presentation, describing the results to date from the Board's Interim resolution. He indicated that Enbridge had received delivery plans for firm transport volumes of 63,000 Gj's/d for the three month winter period in 2010, representing only about 33.5% of the forecast daily delivery volumes for direct shippers. He stated that Enbridge is following-up with those who have not reported.

In response to a question, Enbridge indicated that responses had been received from approximately 90% of those that should have reported. *NOTE TO READER: Since that time Ian MacPherson has confirmed a 99% response result.*

Further questions arose about what the submitted numbers were truly representing; the concern being how the reported numbers related to the expected peak demand or even the expected winter month demands.

Enbridge confirmed that the information provided does not report those things. The reported volumes simply provide the portion of mean daily volumes by pool, contracted over the past three years, that is to be underpinned by firm transport. It is founded on the mean daily volume multiplied by 365 days, divided by 12 months, multiplied by 3 months.

The purpose is to provide an indication of the minimum deliveries that Enbridge can count on in peak demand scenarios, so that Enbridge knows how much additional volume they need to contract for to ensure system reliability.

After substantial discussion the committee acknowledged that the reported information does not provide any additional information about the amount of potential shortfall on peak days, but only how much volume of firm transport is available for a peak day. Enbridge must then contract to make up the difference.

When asked how Enbridge felt about the 63,000 Gj reported volume, Enbridge said, while it is better that the previous year, it falls well short of the 200,000Gj's they were hoping to firm up.

Prior to breaking, IGUA asked Enbridge to circulate the updated exhibit from the hearing (**HD 1.1 p. 3 of 3)** that broke down the direct purchase volumes versus the amounts secured. Enbridge agreed.

Morning Break

Keith began at slide 9 after the morning break. These slides reviewed the options and the issues discusses at the November 16th meeting.

Slides 9 to 12 layout the four (4) options proposed to date, along with the issues as identified by Enbridge. These were:

1. Vertical Slice
2. Solutions (based upon the Interim Resolution)
    a. Board Interim Resolution
    b. EGD interim solution (Modified)
    c. Direct Energy Interim Solution (Modified)
3. Backstopping
4. Curtailment

Keith reminded everyone at the outset of the review that he was looking to committee members to add any options and issues that they could think of.

He pointed out that Slide 11 lays out the Option 2c proposed by Direct Energy, which was the Interim Resolution with firm commitments frozen at the 2009 levels. All the issues were those identified by Enbridge. No other issues were identified by the group at this time.

In reviewing the Curtailment of firm customers on slide 12, Keith pointed out the issues as identified by Enbridge, these included how quickly EGD would be able to identify the party that failed to deliver; the need to install the infrastructure to enable curtailment; and how would costs of the curtailment system be allocated to customer classes.

Enbridge indicated that they were currently trying to establish the infrastructure costs for installation on Enbridge's largest customers and will report that to the group when it is known.

Enbridge pointed out that curtailment works for very few customers, and that it is not a suitable option for the mass market. Others pointed out that not even all large customers can be curtailed; Enbridge agreed.

When IGUA was asked if the description and issues properly captured the curtailment option, since it was their suggestion, they replied yes but added that the group may want to consider some form of voluntary curtailment. Enbridge replied that a voluntary system exists today, primarily in the form of Interruptible contracts. IGUA clarified that they were suggesting a form of contractual commitment to self-curtail, with penalties to address failures to curtail.

IGUA said this leads to an additional issue for this option which is the dependability of voluntary curtailment as a solution to the firm transportation matter.

The next slide “Direct Purchase Large Volume Customer Delivery Volumes” was prepared to highlight the sizable volume that could be made available by interrupting the top 50 customers to lead the discussion of remote shut-off for the curtailment option. It promoted some discussion and a request that the slide be reproduced for the next meeting showing the breakdown of existing interruptible versus firm customers included in each group.

Keith moved on to the next slide #12 that compared other System Operator Functions to Enbridge’s. The others included in the comparison were: Union Gas South, Union Gas North; and GMi.

There was substantial discussion about this slide mostly focused on the comparisons to Union South’s vertical slice and Union North. The discussion highlighted several differences existing between Union South’s vertical slice and what would be the equivalent vertical slice for Enbridge. Those differences, representing added complexity for Enbridge, were considered important to evaluate, because they could support Enbridge’s expressed concern about system reliability even in a vertical slice option.

To assist with further discussion in this area, IGUA asked to have maps showing the TCPL system in Ontario available for the next meeting. TCPL agreed to provide the maps for the next meeting.

In response to a question, Keith confirmed that 100% of GMi’s mass market is underpinned by firm transportation.

Keith moved to Slide 15 showing a table of Options and evaluation criteria. Asking the committee to provide any input they had on the evaluation criteria included in the spreadsheet. Enbridge indicated that the committee would need to fill this table in to assist in a complete evaluation and comparison of the various options. Committee members agreed to do that as a takeaway.

In a more detailed discussion of the Backstopping option, it was agreed that while backstopping was a more expensive option, it could be used in conjunction with one or more of the other options to optimize the mix of transportation assets, potentially reducing the need for firm transportation.

At this point the group was asked if there was any other information that they needed. CCC asked for more details about how Transactional Services (TS) would be impacted by the various options being considered. It was suggested that this evaluation of the TS influence would need to be added to the Criteria table under Ratepayer Impacts. Enbridge agreed.

DE suggested an additional option being "build" of short haul transport should be considered by this committee, particularly as part of the long term solution.

Enbridge agreed that "Short Haul Build" would be added as another option.

Shell took this opportunity to propose another option. Shell felt that if customers could show that they had a supply contract from a financially sound and credible supplier, that it could be used to offset the need for some firm transportation. IGUA questioned how financial credibility could solve a problem resulting from a lack of firm delivery or capacity, and that this suggestion was based upon providing greater comfort for Enbridge short of demanding firm transportation. Shell said there would need to be two components to the Option: first that the suppliers would satisfy certain minimum financial requirements to establish their credibility; and second that they would have to indicated that they were promising firm delivery to the Enbridge distribution area.

Shell agreed that this would not be a solution if it can be shown that there is a real concern about the system physically being able to supply peak demands in a worst case scenario.

CCC suggested that the committee investigate how the IESO handles "prudentials" with respect to contracted supply.

Shell was asked if it could explain to the committee how it can assure customers of firm supply into a franchise area without contracting for firm transportation. The question was asked to provide greater comfort to the committee that a supplier's commitment to supply a delivery area could be used as a proxy for firm transportation.

Shell said it would consider that request, but was concerned that it might give away some proprietary information.

TCPL tried to stress the point that "there is no shortage of capacity on TCPL mainline". The issue is that Enbridge has insufficient contracted capacity, meaning that if Enbridge's demand for more gas came at a time when others were also asking for more gas, it may not be available for Enbridge customers when needed.

IGUA added to that point of understanding by saying that Enbridge's concern is that they are being held accountable for 100% reliability and the only way they have been able to do that is by having a very high percentage of firm transportation. IGUA suggested that what would be required is that the Ontario Energy Board would have to hear the evidence, and conclude that they do not see a capacity problem, and that they excuse Enbridge from the responsibility of providing gas supply on an uninterrupted basis, 24/7.

The closing discussion on potential issues focused on the question of liabilities associated with a failure of the pipeline system to provide natural gas. While it did not culminate in any specific issue being identified, some parties felt that it was worth considering when the group evaluates options; this would be particularly true if the committee chose an option that put greater reliance on supply controlled by others, as would be the case with the option proposed by Shell.

AEGENT asked for some details about the January 13th through 17th, 2009 example of failure to delivery. There were several detailed questions that neither Enbridge, nor TCPL could answer on the spot, and AEGENT agreed to write those questions out to allow Enbridge and TCPL to answer them for the next meeting.

Parties were asked if there was any other data that anyone thought they needed for the next meeting.

DE asked if TCPL could provide some more detail about the "Build" option to help the committee evaluate that option. TCPL felt they could provide something on that.

There were no further requests.

4. Schedule for the Next Committee Meetings

The final slide proposed the dates for the next three meetings, no one present indicated a problem in attending on those dates; OEB staff indicated a potential conflict with an Enbridge proceeding in February at the Board.

The group agreed to set January 21, 2010 as the firm date for the next meeting, and to hold the dates of February 25, 2010 and March 25, 2010 as the tentative dates for the following meetings subject to confirmation.

Adjourn

The meeting was adjourned at 12:30 PM.

Note to Readers:

Action items arising from this meeting can be found in Appendix D.

Appendix A: Meeting Agenda November 20, 2009

STAKEHOLDER CONFERENCE

Friday, November 20, 2009

500 Consumers Road, Spruce Room (Basement)

Firm Transportation

AGENDA

9:00 - 9:10 am **Opening Remarks -** Bob Betts, Facilitator

- Welcome and Housekeeping Items
- Objectives and plan for this meeting

9:10 - 9:30 am **Working Committee Process -** Malini Giridhar, Director Energy Supply & Policy

- Role and responsibilities of the Working Committee

9:30 - 10:30 am **EGD Firm Transportation Presentation -** M. Giridhar/Keith Irani

- Review of the OEB Decision on Firm Transportation
- Review of options and issues
- Daily delivery by customer type
- Overview of functions and responsibilities of Union Gas and GMi as system operator

10:30 am - 10:45 am **Break**

10:45 am - 12:00 pm **General Discussion on Issues and Takeaway -** Bob Betts, Facilitator

- Determine the next steps in terms of issues, deliverables and responsibilities.
- Finalize dates for Working Committee Meeting for Q1.

LUNCH

Appendix B: Participant Listing

Stakeholders

Attendee	Organization
Frank Brennan	AEGENT
Ric Forester	Direct Energy
Ian Mondrow	IGUA
Colin Schuch	Ontario Energy Board
Paul Dumaresq	Shell Energy
Murray Ross	TCPL
Lisa DeAbreu	TCPL
Chris Ripley	Union Gas
Roger Higgins	VECC & CCC

Enbridge Representatives

Attendee	Position
Malini Giridhar	Director, Energy Supply & Policy
Anton Kacicnik	Manager, Rate Research & Design
Robert Bourke	Manager, Regulatory Proceedings
Ian Macpherson	Manager, Direct Purchase
Keith Irani	Manager, Energy Supply Services
Michel Levac	Manager, Gas Supply Projects
Hilmi Muhammad	Manager, Energy Forecasting and Planning

Other

Bob Betts	Facilitator, Regulatory Support Services

Appendix C: Upstream Firm Transportation Working Committee Presentation by Keith Irani

Upstream Firm Transportation Working Committee

November 20, 2009

Firm Transportation Working Committee Opening Remarks – Bob Betts, Facilitator

- Welcome & Housekeeping Items

- Objectives and Plan for the Meeting
  - Review from previous meetings
  - Presentation and discussion of the options, and associated issues to:
    - Gather additional committee input; and
    - Finalize the list.
  - To determine what additional information is required by the working committee to understand and analyze the options.

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Firm Transportation Working Committee Process – Malini Giridhar

- Working Committee Role:
  - To propose various options for long term resolutions of the system reliability issue for presentation to the larger stakeholder group, and eventually to the OEB.

- Responsibilities:
  - To be objective and cooperative
  - To evaluate impacts on all stakeholders
  - To make reasonable efforts to reach consensus
  - Where disagreements can not be resolved, to clearly define the areas of and reasons for the disagreement

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Firm Transportation Working Committee Process – Malini Giridhar

- Working Committee Rules:
  - To attend all meetings in person, unless impossible or impractical
  - To read and prepare in advance of each meeting to maximize efficiency
  - To be open minded in considering various options being reviewed
  - In the absence of a consensus, committee members will be free to take whatever positions they choose before the OEB

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EGD Firm Transportation Presentation

K. Irani/M. Giridhar

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Review – OEB Decision

- .. the Board must support and encourage competition in the market place, that requirement cannot supersede the need to ensure that all system users will have continuous and reliable access to gas at all times, including peak days. The Board therefore concludes that the system reliability issue raised by Enbridge must be addressed.[1]

- The Board is of the view that a long term resolution of the system reliability issue is needed. While the Board is comfortable that the Board's interim resolution will meet reliability requirements for the coming winter, it is not assured that the appropriate long term resolution has been found.[2]

- The Board therefore directs Enbridge to file an application which puts forward various options for the Board's consideration.[3]

- The application should be brought forward with the intention of having the resolution implemented in time for the 2010/11 winter season.[4]

[1] EB-2008-0219 Decision and Order, Phase 2 July 14, 2009 p.7

[2 3 4] Ibid, p.11

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Review – OEB Decision Interim Resolution

- The Board's interim resolution …. will be in place for the upcoming winter and will remain in place until a permanent resolution has been approved by the Board.[5]

- Direct shippers will be required to confirm to Enbridge their gas delivery plans to Enbridge's CDA and EDA for the winter period of January 1 to March 31 of each year, including the amounts to be underpinned by firm transport, no later than November 1 of each prior year, beginning November 1, 2009.[6]

- In summary, the direct shippers will provide the proportional average of the percentage of the firm transport they have used for the past three winter periods plus ten percentage points.[8]

[5-8] EB-2008-0219 Decision and Order, Phase 2 July 14, 2009 p 9-10

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Board Interim Resolution - Results

- For November 1, 2009, EGD has received notification from direct shippers (OTS-ABC) of their gas delivery plans for firm transport (FT, STFT) of 63,000 Gj’s/d for the period January 1, 2010 to March 31, 2010.

- This volume represents 33.5% of the corresponding forecast daily delivery volumes of the direct shippers.

- EGD is in contact with and is awaiting responses from some direct shipper representatives who have not submitted their gas delivery plans for November 1, as per the Board’s Interim Resolution.

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Review – Options for long term resolution

1	Vertical slice	Issues for discussion
	• EGD contracts for FT to the franchise on alternate transportation paths. • Contracted capacity is based on mean daily volume (MDV) requirement for EGD sales and direct purchase customers. • DP market assigned proportional capacity in relation to MDV. • All customers deliver a fixed percentage of MDV to the franchise delivery areas and to Dawn (for transportation paths routed through Dawn). • EGD retains and manages Dawn CDA and EDA transport on behalf of all customers.	• firm customers vs. sales service customers. • contract and credit risk. • grandfathering existing DP arrangements. • turn back policy. • integrated operation of CDA and EDA. • increased administrative costs (IT, FTE). Additional issues from Working Committee

Review – Options for long term resolution

2	Interim	Issues for discussion
	a. Board interim resolution: • direct shippers (OTS-ABC) calculate annual percentage of firm transport for the past three winter periods (Jan 1 to March 31), • average of the three years' percentages, add ten percentage points.	• appropriate level of demonstration? • STFT availability in future? Availability on other transportation paths. • diversity of gas supply in the longer term. • alternate transportation paths. • barriers to contracting for DP market. • grandfathering existing DP arrangements. Additional issues from Working Committee
	b. EGD interim solution (modified): • EGD contracts FT for sales customers only. •DP market demonstrates firm transportation (FT/STFT) contracts from supply basin based on MDV requirement, at a minimum for the period Dec–Mar.	• same as above • administrative costs determining FT requirements & demonstration of FT allocations. Additional issues from Working Committee

Review – Options for long term resolution

2	Interim	Issues for discussion
	c. Direct Energy ▪ Board interim resolution frozen at 2009/2010 winter levels (no additional % for subsequent years)	• 2009 levels do not address system reliability issue. • Not proposed as a long term solution. Additional issues from Working Committee

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Review – Options for long term resolution

3	**Backstopping service**	**Issues for discussion**
	▪ EGD contracts for FT to the franchise on alternate transportation paths for sales customers. ▪ EGD provides backstopping service to DP market to ensure against failure to deliver. ▪ EGD contracts for contingency transport and storage to provide service.	• determining contingency requirements. • appropriate level of transport and storage & peaking. • EGD will require firm short-notice transport and storage with reservation of capacity to respond to failure to deliver. • trade-off between duplication of capacity vs. adequacy of contingency arrangements. • lead time to develop short haul contingency transport. • cost allocation of backstopping service to DP market. • diversity of gas supply in the longer term. • Additional issues from Working Committee
4	**Curtailment of firm customers**	• targeted curtailment in response to failure to deliver • infrastructure and resources requirement for expanded curtailment. • cost allocation – who pays for incremental infrastructure and resources LV or all customers? LVC amenable to option? • administrative costs. • Additional issues from Working Committee

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Comparison of System Operator Functions and Responsibilities

Function	Union Gas South	Union Gas North	GMi	EGD	Implications for EGD
Degree Day planning	• plans and contracts for 44 heating degree days • SOLR	• plans and contracts for a varied level of heating degree days • SOLR	• GMi plans and contracts for 44 heating degree days • SOLR	• EGD plans and contracts for 39.5 heating degree days • SOLR	• EGD has less contracted capacity than GMi and Union Gas to meet contingency supply
Mass Market requirements (Direct Purchase)	• vertical slice and own transport for delivery to Union	• delivers to Union at Empress, Union manages transport	• delivers to GMi at Empress for delivery to franchise	• most customers deliver to in-franchise using non-FT	• TCPL's restrictions on non-firm service would result in a greater proportional cut to EGD's franchise
Large Volume Customers (Direct Purchase)	• vertical slice, allocation and assignment of upstream transportation portfolio	• assigns firm transportation • effective ability to shut off customers due to small number of LVCs	•assigns firm transportation (has approx. 8 customers) • effective ability to shut off customers due to small number of LVCs	• most customers deliver to in-franchise using non-FT • less effective ability to shut off customers due to large number of LVCs	• lower use of FT and lower ability to effect planned load reductions constrains EGD relative to GMi and Union Gas

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Direct Purchase Large Volume Customer Delivery Volumes

Service	Volumes (Gj)	%
Direct Purchase	188,407	100
- Top 50	122,611	65
- Remaining ~450	65,796	35

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* Average day

Impact of Options

	System Reliability			Competitiveness	Ratepayer/ Stakeholder impacts
Options	Firm Transport	Incremental Supply (backstopping)	Load Reduction (curtailment of firm customers)	Impact on Competitive Market	Ratepayer & Stakeholder Impacts
1. Vertical slice	√	–	–		
2. Interim a. Board interim resolution b. EGD interim solution (modified) c. Direct Energy	√	–	–		
3. Backstopping service	–	√	–		
4. Curtailment of firm customers	–	–	√		

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Next Steps and Action items

- Expectations
- Timelines
- Responsibilities

Future Working Committee Meetings

- January 21, 2010
- February 25, 2010
- March 25, 2010

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Appendix D: Summary of Action Items

Page	Task	Responsibility
3	IGUA then made a comment about what they felt would be necessary to properly approach this issue. They felt that they need some form of empirical data to assist in illustrating the existence and the magnitude of the reliability problem as it is today. IGUA felt that might start with some evaluation of what is available on peak days to assist Enbridge with its reliability problem. IGUA stated that this was not an attempt to re-litigate the issue, but only to define the problem to be resolved.	Enbridge
4	While that issue was generally recognized by the group, IGUA and others said they still needed to understand the nature of the problem by knowing what other means were available to Enbridge to make up a shortfall in deliveries on a peak day. If there were no other means of making up a shortfall, then that would illustrate the problem and ideally quantify the magnitude of the problem.	Enbridge
4	IGUA agreed, but added that we need to quantify those potential shortfalls, as well as what quantities are available from various other means to address that problem. Enbridge added that much of that information will have to come from TCPL.	TCPL & Enbridge
5	Enbridge indicated that they had an idea of what the group was looking for in terms of data, and said that much of it exists in evidence in previous hearings, and that they would try to bring additional data to the next meeting.	Enbridge
5	IGUA explained that they wanted to understand what capacity could reasonably be expected to be available in the system for use in a shortfall scenario, along with an estimate of the probability that that capacity would be available on the peak day.	Enbridge & TCPL
5	Enbridge also asked TCPL to try include an analysis of the risks associated with mechanical breakdowns, like compressor failures, in peak load conditions.	TCPL
5	Direct reiterated CCC's point about the need to define system reliability for gas utilities, whether that is by station pressures or capacity coming in, because that would allow measurement and tracking, and better future planning.	Committee
5	TCPL could describe a worst case scenario. That could be based on the highest degree day that would have to be experienced in multiple locations along the pipeline to completely consume the capacity of the pipeline. That estimate of degree days would qualitatively define how probable that event would be.	TCPL
5	IGUA indicated that even a TCPL assessment of the probability of a shortfall in supply in the Enbridge franchise would be helpful.	TCPL
6	AEGENT presented an idea of using the maximum flow or pipeline capacity at all major discharge points on the mainline, add in peak day draw for Enbridge and Union, and then add in projection of potential mechanical failure to determine how much, if any additional capacity would exist in the pipeline. IGUA felt that this would be very helpful in illustrating a system	TCPL

	reliability problem, particularly with the addition of a map showing all the points of interest and a prediction of the probability of such an event. This was later described as the "Maximum Constraint Scenario", and TCPL indicated that they would try to do the analysis. Enbridge added that transmission is clearly where the system reliability issue is focused because Enbridge's low-pressure distribution could not alleviate a shortfall situation utilizing capacity at Parkway. Everyone agreed that regardless of what the analysis shows, there remains a question about how that scenario would change in the future.	
8	Enbridge indicated that they were currently trying to establish the infrastructure costs for installation on Enbridge's largest customers and will report that to the group when it is known.	Enbridge
8	It promoted some discussion and a request that the slide be reproduced for the next meeting showing the breakdown of existing interruptible versus firm customers included in each group.	Enbridge
8	To assist with further discussion in this area, IGUA asked to have maps showing the TCPL system in Ontario available for the next meeting. TCPL agreed to provide the maps for the next meeting.	TCPL
9	Enbridge indicated that the committee would need to fill this table in to assist in a complete evaluation and comparison of the various options. Committee members agreed to do that as a takeaway.	Committee Members
9	CCC asked for more details about how Transactional Services (TS) would be impacted by the various options being considered. It was suggested that this evaluation of the TS influence would need to be added to the Criteria table under Ratepayer Impacts. Enbridge agreed.	Enbridge
9	Enbridge agreed that "Short Haul Build" would be added as another option.	Enbridge
9	CCC suggested that the committee investigate how the IESO handles "prudentials" with respect to contracted supply.	Committee
10	Shell was asked if it could explain to the committee how it can assure customers of firm supply into a franchise area without contracting for firm transportation. The question was asked to provide greater comfort to the committee that a supplier's commitment to supply a delivery area could be used as a proxy for firm transportation. Shell said it would consider that request, but was concerned that it might give away some proprietary information.	Shell
10	AEGENT asked for some details about the January 13th through 17th, 2009 example of failure to delivery. There were several detailed questions that neither Enbridge, nor TCPL could answer on the spot, and AEGENT agreed to write those questions out to allow Enbridge and TCPL to answer them for the next meeting.	Enbridge
10	DE asked if TCPL could provide some more detail about the "Build" option to help the committee evaluate that option. TCPL felt they could provide something on that.	TCPL

Working Committee Notes

Enbridge Gas Distribution Inc.
Working Committee Meeting 2
On
System Reliability

January 21, 2010
L&L Boardroom
Enbridge Gas Distribution
Consumers Road
Toronto, Ontario

Prepared By:
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Putting the Pieces Together

Table of Contents

Enbridge Gas Distribution Inc.
Working Committee Meeting 2
On
System Reliability

1. Opening and Introductory Remarks

Presented by Bob Betts, Facilitator

The meeting was called to order at 9:20 a.m. Bob Betts welcomed all those in attendance.

He acknowledged that everyone had been present at a previous meeting and that introductions around the room were not necessary at this time. He did mention Julie Girvan, who was attending the meeting on behalf of both CCC and VECC, as Roger Higgin had done the meeting prior.

Bob then took a moment to recap activities that had taken place since the November 20th meeting.

He started by stating that the committee's decision to change the names of both committees had been implemented both on paper and the website. Notes had been circulated and the takeaways by Aegent, TCPL and EGD had been completed to the extent possible. Both TCPL and EGD have found that they need additional time to fully respond to their action Items, but will be reporting back today to the extent that they can.

In that respect, TCPL's abbreviated presentation will be made by Lisa DeAbreu, instead of M. Wallawein and K. Schubert as was indicated on the agenda.

He indicated that a further agenda change resulted from the need to review the Action Item List from the November 20th meeting. Bob handed out the reformatted Action Item List and indicated that he and Keith Irani would be discussing it with the committee later in the meeting.

Bob indicated that Brad Janzen, Direct Energy was attending on the phone and Vince DeRose; CME would be calling in shortly. He then turned the meeting over to Enbridge for their presentation.

2. EGD System Reliability Presentation – Keith Irani / Malini Giridhar

(Starting on Slide 3 of the Presentation included in Appendix C)

Keith Irani first provided an update on the results of the implementation of the Board's Interim resolution.

The first item of note was that EGD had received notification from all direct shippers of their gas plans for firm transport, both FT and STFT, for the period Jan 1, 2010 to Mar. 31, 2010 as per the Board's order. The data received indicated firm commitments for 65,741 Gj/d for that period.

In response to a question from Board Staff, Keith indicated that this represented an incremental firm transport commitment of approximately 40,000 Gj/d net of EGD's assigned FT capacity to OTS-ABC customers, this was well short of the 200,000 Gj/d incremental increase that EGD proposed in Phase 2 of the 2009 proceeding.

In response to a question about the portion of FT versus STFT, Enbridge indicated that the Board did not require shippers to specify the proportions of FT versus STFT, only their total planned firm transport volumes.

CCC asked what the implications were for this shortfall in FT commitments versus the 200,000 hoped for by EGD, primarily from an operational perspective.

Malini Giridhar indicated that the weather conditions have been favourable so far this year and EGD had not yet come close to peak day conditions; however, the concerns remain the same, that if peak day conditions are met that some deliveries may not show up, particular if there is a coincidental transportation limitation.

In response to a Board Staff question, Malini indicated that the highest send-out this season was approximately 2.8 bcf, which is quite a bit lower than the peak day of 3.5 bcf. In comparison, the January 2009 cold snap saw a send-out in the range of 3.2 to 3.3 bcf.

Last January's anxious moments occurred in a degree day circumstance which was well below EGD's design degree days, approximately 34 DD versus EGD's 39.5 design DD. Despite that, supplies were uncomfortably tight as will be discussed later in the meeting.

Aegent asked EGD about a recent incident when they called an OFO day, "operational flow over" day, which is when unbundled customers are required to bring in sufficient gas to match their consumption. He asked why was it called and how that procedure is different from typical curtailment.

Enbridge indicated that they provide 24 hours notice for OFO days, versus 4 hours notice for curtailment. It is therefore typically a decision made at least 24 hours in advance of a pending supply concern. In the recent case there was an expectation of cold weather, on a weekend when markets would be closed, and EGD deemed it best to have its large customers not draw on the system.

Referring to Slide 12 and the mean daily volume for OTS ABC customers of 250,000 GJ, IGUA asked for clarification with respect to the derivation of the 200,000 incremental firm transport that EGD wanted.

Malini indicated that EGD was asking for 90% firm coverage and taking into account the 25,000 that already existed, there had to be roughly an additional 200,000 GJs added ((250,000X 90%) - 25,000 existing).

Keith returned to slides 5 to 9 that laid out the various options that have been identified for a "long term resolution". Since all but the last two had been reviewed before, he was prepared to move to the two that were recently added, skipping the rest; however, the group was interested in reviewing all the options.

2.1. Review of Options for a Long Term Resolution

2.1.1. Vertical Slice

Keith briefly described the "Vertical Slice" option and the issues for discussion.

CCC asked how the proposed vertical slice compared to Union's vertical slice. EGD said the concepts are the same, except that in EGD's case if a tranche of transport comes up for renewal, EGD would make a decision on renewal versus alternate path, but under any circumstances, the customer would remain firmed up. Union added that their approach is based upon a stranded cost issue and their customers could turn back their assignment of capacity, as long as Union could then turn back the capacity to the pipeline.

2.1.2. Options Based upon the Board's Interim Resolution

2.1.2.1. The Board's Interim Resolution

Continue the use of the Board's Interim Resolution on a permanent basis.

2.1.2.2. Interim Resolution Model (EGD modification)

This would be the Board's model, except that EGD would continue to plan for sales customers while direct purchase customers would be required to provide firm transport. Also the planning period would be from December to March, as opposed to the Board's January to March.

In response to a question from IGUA, Keith clarified that the EGD modification is still based upon deliveries eventually being 90% firm.

2.1.2.3. Interim Resolution Model (Direct Energy modification)

This option would be the same as the Board's Interim Resolution with the exception that the firm transportation underpinning would be frozen at current levels.

Recognizing EGD's concern that the DE modification would still exhibit a lack of assured system reliability, CME asked EGD if this or any of the other Interim Resolution type options would lead to a material impact on rates to customers that do not choose supply by a direct marketer. Malini indicated that there weren't any obvious impacts apparent at this stage as long as the chosen scenario allowed EGD to source out the supply arrangement and then allocate those to direct purchase customers.

EGD added however, that if deliveries failed to show up as a result of insufficient FT underpinning, that there could be an added cost to ratepayers for Enbridge to arrange for other supplies.

IGUA assumed that those types of costs would be allocated to the offending parties and not to the general ratepayer. EGD clarified that such allocation is not happening currently and that both the added delivery costs and the penalties imposed for failure to deliver should probably go into the PGVA for later clearance, and it could not be determined at this stage what the net result would be on rates.

IGUA added another potential impact on rates depending on the Board's expectations that EGD will always maintain system reliability. IGUA hypothesized that in one scenario the Board could adopt a DE type solution, with lower FT underpinnings, on the assumption that adequate capacity would always be available when called for. If they did that and also relieved EGD of the burden of maintaining reliability under any circumstances there would be little or no need for expensive backstopping arrangements. If however, the Board did not relieve EGD of the burden for maintaining system reliability under a diminished FT scenario, EGD would be forced to make potentially expensive backstopping arrangements to fulfill the Board's expectations. That could add substantial distribution costs.

CME suggested and others agreed that each of these and all other options must be evaluated fully for all the incremental costs of the option, and other impacts to stakeholders.

2.1.3. <u>Backstopping Service</u>

Keith went on to review the Backstopping Service option.

IGUA asked a question to clarify the differences between FT service and Backstopping Service in terms of dependability and cost. IGUA asked if Backstopping was used as a mere substitute for Firm Transport, would the costs not be the same or maybe even higher than requiring Firm Transport?

Malini responded by saying that if Backstopping was used as a substitute for FT it should be a higher quality transport asset and would therefore represent a higher cost. She reasoned that Backstopping would be used in a scenario when deliveries failed to show up in the area. Typically that situation would not be apparent until after the timely nomination window had passed, and as such EGD would have already missed its opportunity to utilize its firm transport assets.

To be effective, the Backstopping arrangements would have to be short notice services in combination with high deliverability storage, and as such would carry a higher cost than FT. Even peaking services requiring advance commitments are not well suited to compensate for unexpected failures to deliver.

CCC asked how the added costs of Backstopping would be allocated. EGD indicated that if the direct shippers were required to make the backstopping arrangements, the costs would be theirs. If however the Board felt that the backstopping served all customers, then the costs would be allocated to all customers.

CCC asked all committee members if anyone saw this to be an attractive option. Shell responded that it could be a very attractive option if it was used only when there was some expectation of delivery problems. Direct Energy responded by saying that it sounds like a very expensive form of added insurance which should not be considered unless there was a proven risk to system reliability.

EGD added that backstopping would only be a necessity in the absence of firm transport commitments, the requirement for FT commitments combined with stiff penalties like those used in the past would largely eliminate the need for backstopping arrangements. Unfortunately, penalties, without a firm transport construct cannot provide the same commitment to deliver.

CCC asked where “penalties” fit into this question. EGD responded with their opinion that unless the penalties are established to be equivalent to the cost of demand charges paid to obtain alternate supply, there will always be the opportunities for gaming.

Shell agreed with EGD that that kind of a charge is the only way to ensure that deliveries will arrive.

2.1.4. Curtailment of firm customers

Keith started this section by reminding the committee that this referred to physical curtailment of firm customers who failed to deliver, not customers contracted for interruptible service.

The primary issue with expanded curtailment is how EGD could physically implement such a curtailment and which customers would be targeted; i.e. all firm customers, only large volume customers, etc.

Some customers can not afford to be curtailed due to the nature of the activities, i.e. manufacturing facilities that would face financial losses if processes were interrupted unexpectedly.

In response to a question by CCC about costs of curtailment and allocation of such costs, EGD responded that this option would add costs such as: installation of remote shut-offs, added SCADA monitoring costs, the need to add a gas controller to monitor consumption, etc. The question of allocation relates to who would pay these costs: the large volume firm customer that agrees to these curtailment protocols or all customers on the premise of it being a system reliability component?

IGUA pointed out that curtailment could take two forms, the first being physical curtailment using remote shut-off technology and the other being some form of voluntary compliance to a curtailment order where EGD could expect a reasonable portion of compliance by the firm customer pool. IGUA suggested that many large volume customers might prefer one of those two options in comparison to the requirement to provide 90% firm transport.

The group discussed the added issue of how EGD could be certain that interruptible customers in fact shut down their consumption when ordered to do so. It was acknowledged that compliance by interruptibles may not be 100%, which would further complicate an emergency curtailment situation. EGD said that whatever measures were put in place to ensure compliance by firm customers would also be applied to interruptible customers, i.e. remote shut-offs. EGD also said that on typical peak-days, if interruptibles do not comply, EGD can rescind their interruptible status and force them to go to firm distribution service.

EGD and Union pointed to another cost consideration and that is the cost to large volume, firm customers who are shut-down in the middle of their normal daily activities. Union referred to comments from their customers that in many cases the costs of the natural gas are very minor in comparison to the labour, production and sales costs associated with a production shut-down. Many would say that curtailment is not an option, system reliability must be maintained. IGUA pointed out that these customers should only have one choice and that would be to contract firm.

IGUA said that when greater detail is known about curtailment, they would be prepared to survey their members about curtailment and to provide that feedback to the committee.

2.1.5. <u>Firm Delivery (underpinned by financial credit worthiness)</u>

Paul Dumaresq of Shell explained this option, since it was their proposition. Shell indicated that this option would be based upon a supplier, with certain minimum financial credibility, providing a letter of assurance guaranteeing that firm deliveries would be provided into the delivery area, under any and all conditions, except for force majeure or some other unusual physical failure.

The premise is that suppliers, such as Shell and BP, would not risk the potential downgrade of the credit rating by failing to deliver contracted supply.

After a question by IGUA, Shell added that there could be firm transport capacity contracted by Shell to back their commitment, but that their experience is that there will always be enough gas delivered into a delivery area, it is just a question of how much that gas might cost (the exception might be a pipeline break or a force majeure). In Shell's case, they would pay whatever it would cost to fulfill their contractual obligations, and they would use any number of supply options to do that.

Aegent asked how this is materially different for EGD, and Shell responded that it was different in two ways; first that EGD does not currently require end-use customers to provide a document from their supplier committing to firm deliveries to the customer, and the second is that there is currently no requirement for suppliers to verify their credit worthiness.

Union asked if Shell is suggesting that EGD could reach back to Shell to recover costs if Shell failed to deliver. Shell stated that this proposal was not based upon the supplier being willing to accept liability for costs falling out of a failure to deliver.

Shell asked EGD if this was not just a concern about whether or not gas “showed up in the area”. Malini answered that ultimately that is the issue, but EGD is obligated to provide due diligence before any potential system reliability issue might happen, to ensure that system planning is reasonable and responsible. That due diligence would be less critical if some other party was willing and able to assume the liability for a system reliability problem, or if the Board relieved EGD of system reliability accountability.

Direct Energy commented that this option is not very different from what is happening today, except that Shell’s guarantee for delivery, would be used in place of the customers guarantee, all underpinned by a credit rating. Based upon the good credit rating enjoyed by DE, there would be no beneficial change.

Both CCC and EGD also expressed concern about the effect this approach would have on the competition among suppliers, forcing customers to contract with suppliers with certain credit ratings.

Rather than continuing the discussion on this topic, EGD asked Shell to review the other issues raised on slide 9 and prepare its position on them to be reported to the committee for the next meeting.

Paul agreed to do that.

2.1.6. <u>Short Haul Build</u>

This was a proposal put forth by Direct Energy. Ric Forster described it as a potential market solution to a perceived reliability concern. He stated DE’s position that they believe that Enbridge is in the best position to determine whether the additional short haul is required. If EGD chose to build it then some market participants, possibly even DE would contract for assignment of some of that capacity.

This would allow the market to decide if additional short haul should be built for backstopping services, or for short haul assignment, or possibly as additional capacity for design day changes.

Enbridge agreed that it could be a way of reducing system reliability concerns by providing short haul capacity back to the large storage area at Dawn. It would be best considered within the framework of some other option such as: vertical slice assignment, or as part of a backstopping plan or in conjunction with a change in EGD’s design day plan and a higher degree day.

IGUA felt that while a short-haul build could be a solution to the issue, it would be inappropriate for the Board to use its power to select short haul build as the single and best solution. If the Board finds that there is a system reliability concern, it would be more appropriate for the Board to order the 90% firm target and leave it to the market to decide how best to provide the firm transport:

- additional firm on long haul;
- additional short haul build, or
- some other form of firm capacity.

After a great deal of discussion involving the entire committee, the group reached a consensus that short haul build would not be considered as an option unto itself, but that it would be subsumed into the considerations of vertical slice and backstopping. It could be an important tool in support of either of those two options. EGD will change charts to reflect this.

The committee then broke for a short recess.

Morning Break

After the break, Keith restarted his presentation at slide 10.

This slide was intended to explain how EGD fills its Design Peak Day portfolio

He started with the 29% tranche of the peak day supply represented by EGD transport and direct shipper deliveries.

In response to a question from IGUA, EGD clarified that this tranche is approximately 50% mass market and 50% direct shipper, and therefore this consultation process is focusing on firming up 90% of 50% of this 29% tranche, roughly speaking firming up 90% of 15% of the Peak Day portfolio. The slide also pointed out that while this volume represents only 29% of the capacity required on a peak day; it represents 50% of the volume required on a typical winter day.

The discussion about this chart and particularly the direct shipper component prompted EGD to offer to revise and redistribute the chart breaking out that portion that was direct shipper only, and if possible to further breakout that portion which is Ontario transport service versus western. The purpose would be to better describe the portion of a Design Peak Day portfolio that was related to EGD's request for 90% firm transport. EGD further agreed to include the approximate volumes attached to each of the portions of the chart.

Keith went on to describe the middle tranche as the 55% portion of Design Peak Day that EGD would expect to make up from storage, and top tranche, as the 16% of Design Peak Day that EGD would get from:

- curtailing interruptible customers,
- accessing peaking supplies and
- utilizing other purchases at EGD's delivery areas for incremental supply.

    Note of Clarification: Following the meeting, Hilmi Muhammad advised that the third bullet point above was incorrect. He noted that on a peak day EGD would not have purchases at Dawn because all of EGD's transport would have been maximized.

In response to a question by IGUA, EGD added that the split between peaking and curtailment in this tranche was about 60% peaking and 40% curtailment. EGD agreed to try to show that break down on the revised chart also.

Slide 11 showed the group how the availability of STFT capacity into the CDA changed on TCPL's mainline in January 2009. That was the period marked by cold weather across the country and particular capacity crunch January 14 to 18. STFT capacity declined from over 1 million GJ on January 1 to only 370,000 on Jan 14, bottoming out to no STFT capacity availability on January 18th. EGD added that this situation began to improve for them on the 18th as the cold moved east; on the 18th the CDA returned to 24.8 Degree Day conditions. IGUA posed the scenario that if the weather forecast for January 19/20 had predicted further cold temperatures, that EGD would not have been able to access any additional STFT capacity and EGD confirmed that to be the case.

TCPL confirmed that this condition lasted for three days, until the 21st, and that there was no STFT capacity or capacity from interruptibles available throughout that period.

DE pointed out that one cannot conclude that this would have led to a supply problem, because it could have been that there was no capacity available because all those direct shippers that had to provide deliveries had acted diligently in securing those capacities. The chart could not prove that by itself.

The only thing that can be concluded is that any party needing additional capacity to that which they already held in contracts, could not get that capacity from the 18th to the 21st.

EGD had referred to an Undertaking that they filed in the hearing that compared contracted capacity to actual flow and DE asked that it be provided to the committee; EGD agreed to provide that.

TCPL was asked to layer on additional information including: STFT contracted, STFT flowed, interruptible contracted, and interruptible flowed.

EDG added that the committee must also consider the fact that the degree days which were substantially better than EGD's design degree days, 24.8 versus 39.5. EGD also felt that evaluation of flows and capacities should include possible consideration of how TCPL equipment failures could affect capacities.

It was agreed that TCPL and EGD should include the above information in the face of various scenarios of weather and equipment failure.

TCPL was finally asked to try to develop the information for the remained of January 2009 also.

The next two slides, 12 and 13, provided the group with a better understanding of the breakdown of EGD's customer profile by OTS Non ABC and OTS ABC; and then a further analysis of the top 50 customers broken down by firm versus interruptible.

In response to a question about whether some customers could be partially interruptible, EGD confirmed that there are many of their interruptible customers that had some percentage of their volume that could not be interrupted. Since these customers still only have one meter, it became apparent that even they could not be cut-off completely, but only asked to curtail to the extent that their contracts required. This cast some question about the effectiveness of a remote shut-off valve to control their consumption.

Slide 14 spoke to questions about the costs of curtailment, but Keith indicated that they were still working on the full costing analysis and that he would report on that in a subsequent meeting.

The slide also highlighted another contractual issue that would further diminish EGD's ability to curtail customers by means of a remote shut-off. This issue related to the determination of the Authorized Volume as defined in EGD's Rate Handbook. In an example provided in that slide a customer would still be entitled to draw an Authorized Volume which would be a portion of the Contract Demand volume, even if they failed to deliver their gas to the area.

EGD provided further clarification on this item in the following points: in an emergency situation, the right to an Authorized Volume could be superseded by the use of the Force Majeure clause; and the authorized Volume example only applies to bundled customers, who still receive load balancing services from EGD. Unbundled customers are expected to provide their own load balancing and can be cut-off immediately.

The next two slides presented EGD's view of the impact assessments for each of the options. Keith indicated that EGD needs the input of committee members to fill this out completely.

It was suggested that EGD send out an electronic version of this table to allow committee members to add their comments, and then return it to Enbridge; EGD agreed to do that. EGD offered to provide some additional descriptive details on the slides to assist stakeholders in understanding the options.

CCC, CME and to some degree IGUA felt it would be difficult for them to fill the table in at this time. CCC suggested they would be more comfortable providing some initial comments now, with the intent of allowing the full committee to discuss all the input in a later meeting. CCC felt that this could generate a "group" response.

It was agreed that committee members were free to add extra columns or adapt the table anyway they wanted to feed the next discussion.

EGD asked Shell to fill in the boxes for Option 5. Firm Delivery / Financial rating.

As a point of clarification, it was suggested that the Options listed on the table as "2. Interim", including 2a, 2b, and 2c, are misnamed because they are not interim solutions; they are being considered as permanent solutions.

Keith moved on to the last slide showing the next two meetings and highlighted EGD's thoughts to use the next meeting to review the analysis of the options and EGD's proposal.

DE suggested that it may be too early to consider EGD's proposal, when the committee hadn't yet determined that there is a system reliability issue, and said we may need more than a morning to deal with that question. EGD accepted that concern and asked TCPL when they would be ready with that information.

IGUA felt that the committee should not stop evaluating the options while members debate whether or not a problem exists, particularly since all stakeholders may not be able to agree about whether a system reliability problems exists or not.

TCPL admitted that this is a very difficult package to deliver but they are getting very close, but that felt they could deliver what the committee wants in a couple of weeks

As a result of comments received, everyone agree that the committee would place TCPL's data as the primary agenda item for February 25th, but that analysis of the options would continue in parallel.

TCPL agreed to try to circulate their data a week prior to the February 25th meeting.

Lunch Break

The meeting broke for a light lunch at 12:30 PM and reconvened at 1:00 PM to complete the meeting. Paul Dumaresq of Shell, left the meeting during this lunch break, but took TCPLs presentation with him to review later.

3. TransCanada New Capacity Open Season Details, Enbridge Reliability Working Committee Meeting, Lisa DeAbreu, TCPL,

(Lisa's presentation is included in Appendix E)

Lisa began this presentation with a slide showing TCPL's mainline system from western basins to eastern markets. She specifically pointed out the CDA and EDA, the Central and Eastern Delivery Areas in their Eastern Delivery Zone. Hard copies of these maps were provided to committee members.

TCPL then provided a high-level analysis of short-haul capacity expansion out of Parkway. It was suggested that expansion capacity could be in-service as early as November 2012, and that four (4) facility improvements could provide as much as 1,290,000 Gj/d additional capacity into the CDA at a projected cost of just over $300 million.

Lisa pointed out that this expansion would require expansion investments in pipelines supplying Parkway; i.e.: Union from Dawn to Parkway.

She described the process for a new build including the requirements of an "open season", backstopping contracts and 10-year contractual commitments. Lisa indicated that before they entered into a new build for the additional capacity requirements, TCPL would first try to satisfy the additional requirements by accessing alternate delivery opportunities, but even in that case, 10-year contractual commitments would be necessary for either a new short haul build or pursuing alternate delivery opportunities.

In response to a question, Lisa indicated that the costs of the build would be rolled into TCPL's overall rate base for toll making purposes.

TCPL explained why and how such a Parkway expansion could have upward pressures on TCPL tolls, both for short and long haul shipments.

4. Closing remarks

In closing the meeting, Bob Betts turned the committee's attention to the Action Item List that was handed out earlier in the meeting. He indicated that it was identical to the listing that appeared in Appendix D of the November 20, 2009 Notes, except that each action item had now been labeled to facilitate later reference.

He indicated that Keith Irani had volunteered to review each item on the list and summarize how and where it had been dealt with. In the case where the matter has not yet been dealt with, he would indicate that also. That analysis by Keith would be sent to each committee member for their review.

If anyone feels that an action item still requires additional work, they will be invited to reply to Keith so that he can address that request as soon as practical.

Adjourn

With that, the meeting was adjourned at 1:30 PM.

Note to Readers:

Action items arising from this meeting can be found in Appendix D.

Appendix A: Meeting Agenda January 21, 2010

COMMITTEE MEETING

Thursday, January 21, 2010

500 Consumers Road, Learning & Leadership Board Room
(Please enter via Link Security/Employee Entrance)

System Reliability

AGENDA

9:00 - 9:10 am	**Opening Remarks -** Bob Betts, Facilitator ▪ Welcome and Housekeeping Items ▪ Objectives and plan for this meeting
9:10 - 10:30 am	**EGD System Reliability Presentation -** M. Giridhar/Keith Irani ▪ Board Interim Resolution – Results Update ▪ Review – Options for long term resolution ▪ Impact of Options
10:30 am - 10:45 am	**Break**
10:45 am - 11:45 am	**TransCanada Pipelines Presentation –** M. Wallawein /K. Schubert
11:45 am - 12:00 pm	**Next Steps -** M. Giridhar/Keith Irani ▪ Future Meetings

LUNCH

Appendix B: Participant Listing

Stakeholders

Attendee	Organization
Frank Brennan	AEGENT
Vince DeRose	CME
Ric Forster	Direct Energy
Jamie Humble	Direct Energy
Brad Janzen	Direct Energy
Ian Mondrow	IGUA
Colin Schuch	Ontario Energy Board
Paul Dumaresq	Shell Energy
Murray Ross	TCPL
Lisa DeAbreu	TCPL
Chris Ripley	Union Gas
Don Newbury	Union Gas
Julie Girvan	VECC & CCC

Enbridge Representatives

Attendee	Position
Malini Giridhar	Director, Energy Supply & Policy
Keith Irani	Manager, Energy Supply Services
Hilmi Muhammad	Manager, Energy Forecasting and Planning
Robert Bourke	Manager, Regulatory Proceedings
Ian Macpherson	Manager, Direct Purchase
Michel Levac	Manager, Gas Supply Projects

Other

Bob Betts	Facilitator, Regulatory Support Services

Appendix C: EGD System Reliability Presentation by Keith Irani / M. Giridhar

ENBRIDGE

System Reliability Working Committee

January 21, 2010

System Reliability Working Committee
Opening Remarks – Bob Betts, Facilitator

- Welcome & Housekeeping Items

- Objectives and Plan for the Meeting
  - Review from previous meetings
  - Presentation and discussion of the options, and associated issues to:
    - Gather additional committee input; and
    - Finalize the list.
  - To determine what additional information is required by the working committee to understand and analyze the options.

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EGD System Reliability Presentation

K. Irani/M. Giridhar

Board Interim Resolution – UPDATE

- As directed by the OEB, for Nov. 1, 2009, EGD has received notification from direct shippers (OTS-ABC) of their gas delivery plans for firm transport (FT, STFT) of 65,741 Gj/d for the period January 1, 2010 to March 31, 2010.
- Includes EGD FT assignments to OTS-ABC customers of 25,389 Gj/d.
- OEB directive for Nov 1 met by all OTS-ABC customers.

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Review – Options for long term resolution

1	Vertical slice	Issues for discussion
	• EGD contracts for FT to the franchise on alternate transportation paths. • Contracted capacity is based on mean daily volume (MDV) requirement for EGD sales and direct purchase customers. • DP market assigned proportional capacity in relation to MDV. • All customers deliver a fixed percentage of MDV to the franchise delivery areas and to Dawn (for transportation paths routed through Dawn). • EGD retains and manages Dawn CDA and EDA transport on behalf of all customers.	• large volume customers vs. general service customers. • contract and credit risk. • grandfathering existing DP arrangements. • turn back policy. • integrated operation of CDA and EDA. • increased administrative costs (IT, FTE). <u>Additional issues from Working Committee</u>

ENBRIDGE

Review – Options for long term resolution

2	Interim	Issues for discussion
	<u>a. Board interim resolution</u>: • direct shippers (OTS-ABC) calculate annual percentage of firm transport for the past three winter periods (Jan 1 to March 31), • average of the three years' percentages, add ten percentage points.	• appropriate level of demonstration? • STFT availability in future? Availability on other transportation paths. • diversity of gas supply in the longer term. • alternate transportation paths. • barriers to contracting for DP market. • grandfathering existing DP arrangements. <u>Additional issues from Working Committee</u>
	<u>b. EGD interim solution (modified)</u>: • EGD contracts FT for sales customers only. • DP market demonstrates firm transportation (FT/STFT) contracts from supply basin based on MDV requirement, at a minimum for the period Dec–Mar.	• same as above • administrative costs determining FT requirements & demonstration of FT allocations. <u>Additional issues from Working Committee</u>

Review – Options for long term resolution

2	Interim	Issues for discussion
	<u>c. Direct Energy</u> ▪ Board interim resolution frozen at 2009/2010 winter levels (no additional % for subsequent years)	• 2009 levels do not address system reliability issue. • Not proposed as a long term solution. <u>Additional issues from Working Committee</u>

ENBRIDGE

Review – Options for long term resolution

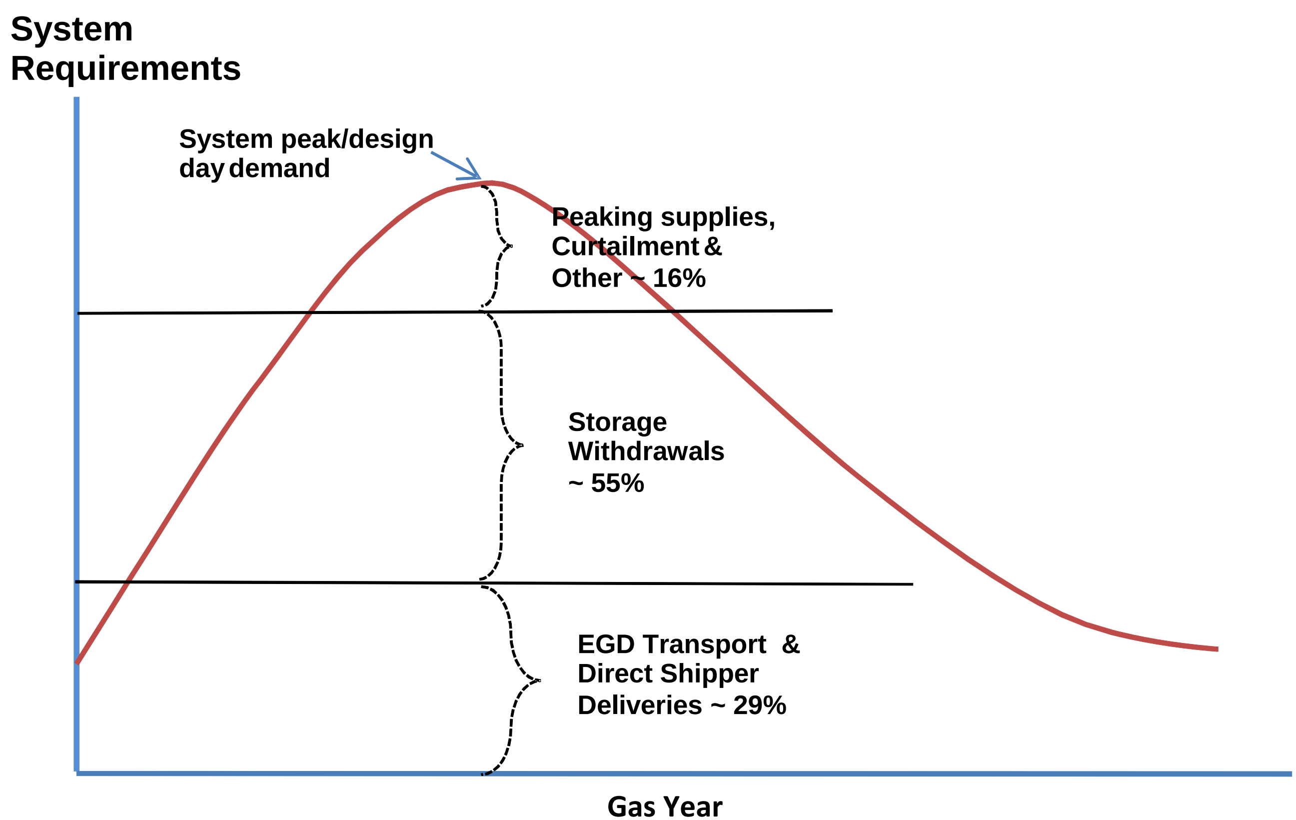
3	**Backstopping service**	**Issues for discussion**
	▪ EGD contracts for FT to the franchise on alternate transportation paths for sales customers. ▪ EGD provides backstopping service to DP market to ensure against failure to deliver. ▪ EGD contracts for contingency transport and storage to provide service.	• determining contingency requirements. • appropriate level of transport and storage & peaking. • EGD will require firm short-notice transport and storage with reservation of capacity to respond to failure to deliver. • trade-off between duplication of capacity vs. adequacy of contingency arrangements. • lead time to develop short haul contingency transport. • cost allocation of backstopping service to DP market. • diversity of gas supply in the longer term. • Additional issues from Working Committee
4	**Curtailment of firm customers**	• targeted curtailment in response to failure to deliver • infrastructure and resources requirement for expanded curtailment. • cost allocation – who pays for incremental infrastructure and resources LV or all customers? LVC amenable to option? • administrative costs. • Additional issues from Working Committee

Review – Options for long term resolution (New)

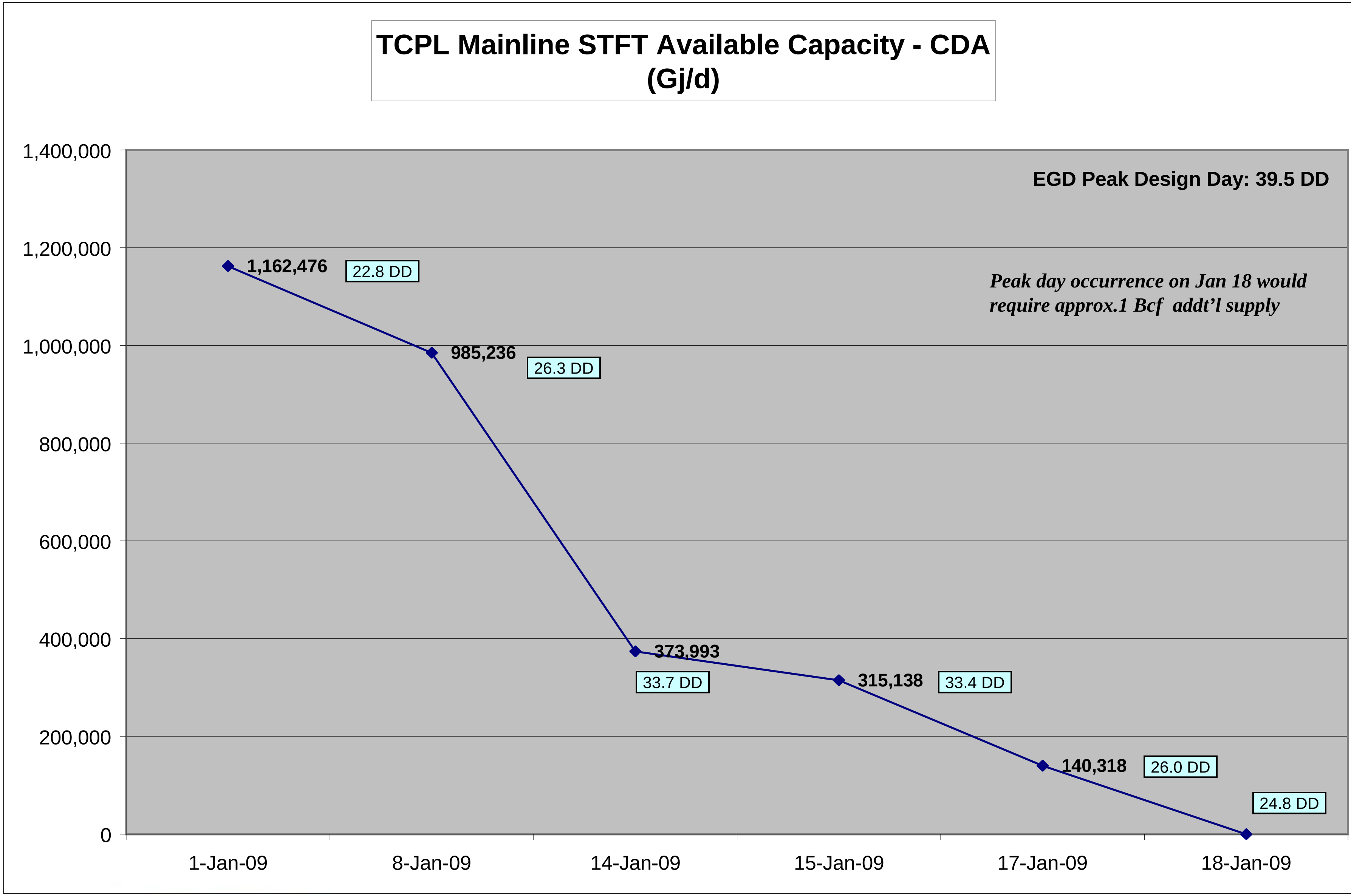
5	**Firm Delivery (Shell Energy)**	**Issues for discussion**
	1. Direct Purchase Eastern delivery clients of EGD must provide written documentation showing they possess firm deliveries to the Enbridge system from their supplier. 2. Supplier must meet a minimum credit/financial threshold that is agreed to by the Working Committee and the stakeholder group.	• definition and criteria that meets firm delivery. • documentation, validation • consequences of failure to deliver: impacts, penalties • determinant of minimum credit/financial threshold – credit rating? supply obligation in aggregate? marketer specific? • LOC, parental guaranty, others? • monitoring and oversight responsibility – price volatility impact of credit/financial threshold • impact on competition – non-competitive aspects; ease of entry, others? • financial credibility solve the problem of a lack of firm transport? • Additional issues from Working Committee
6	**Short-haul build (Direct Energy)** ▪ new short haul capacity from Parkway to EGD CDA/EDA	• Build requirements. •TCPL's contract process for new capacity. • who contracts for capacity? Assignment? • will new capacity meet DP delivery obligation? • stranded assets issue • Additional issues from Working Committee

ENBRIDGE

EGD Design Peak Day Portfolio

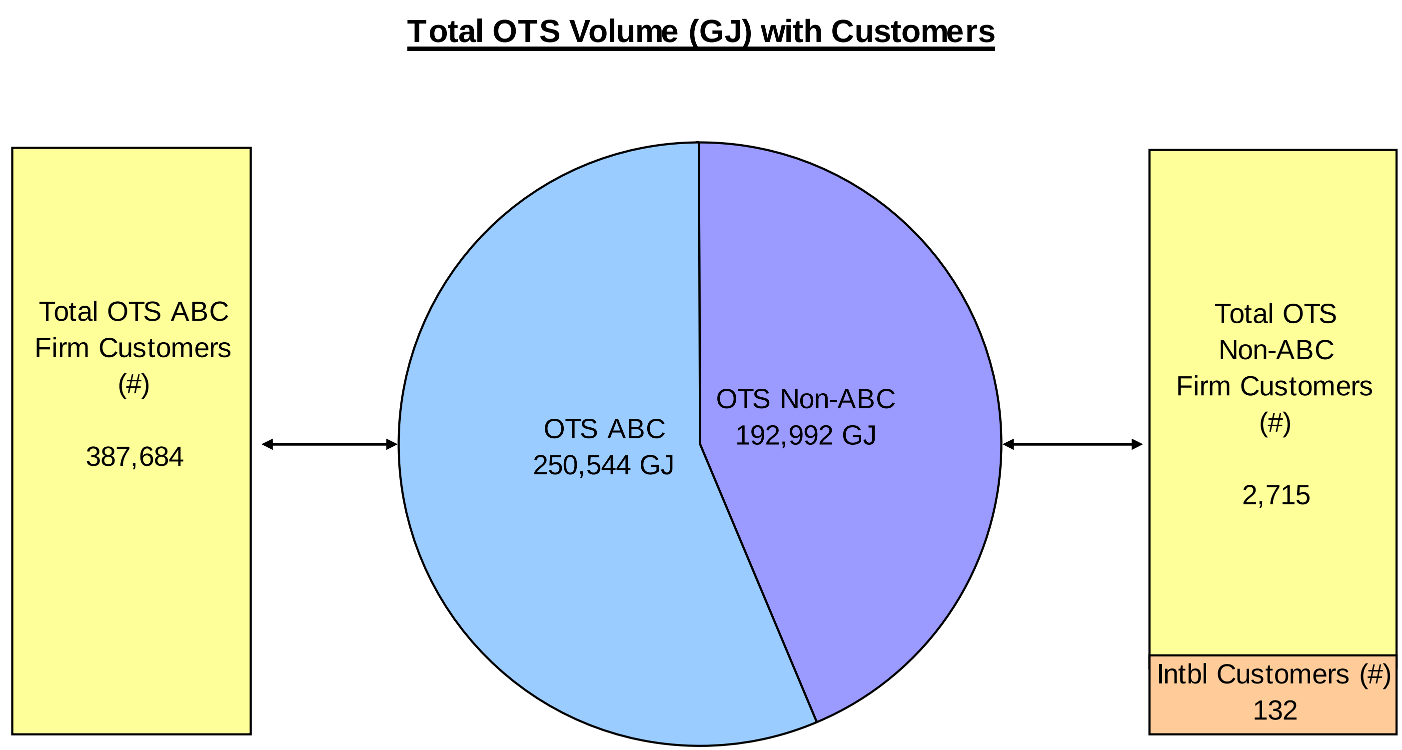


EGD transport & direct shipper deliveries make up over 50% of average winter day requirements



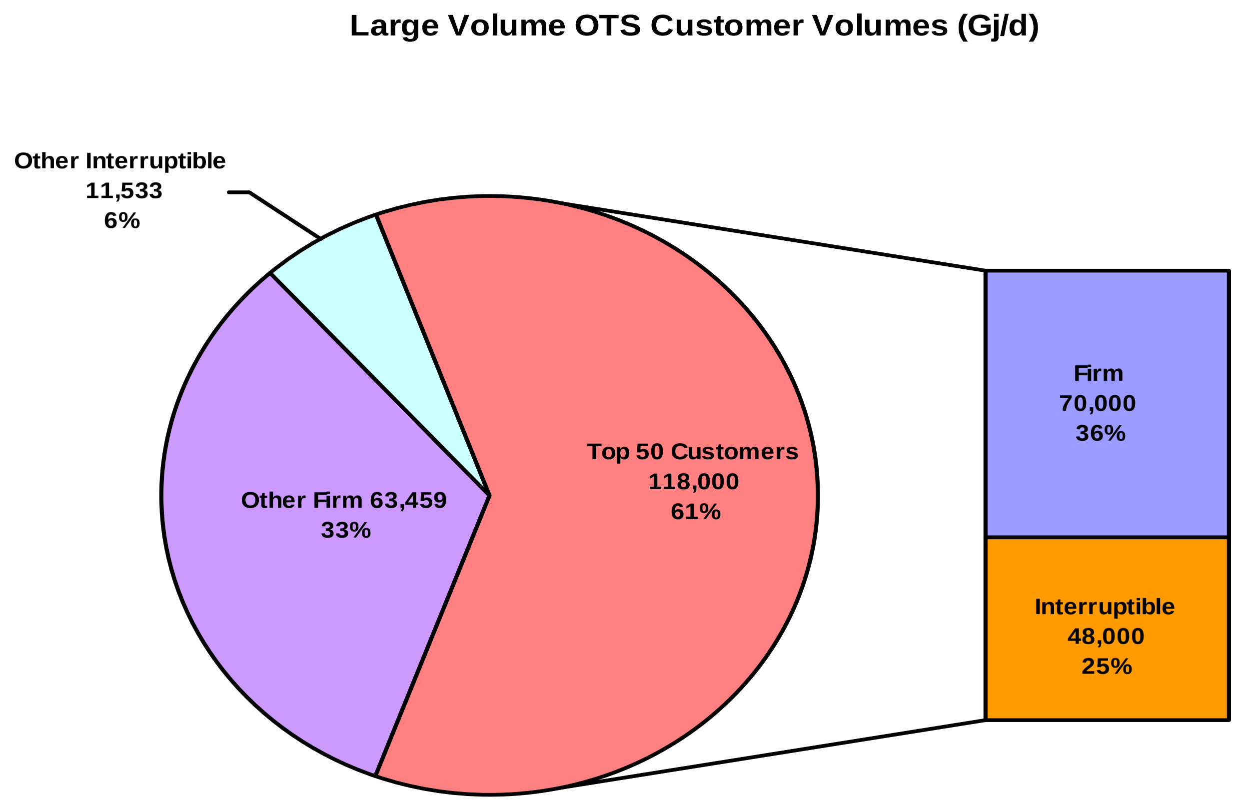
Source: TCPL Mainline STFT Winter Open Season Postings
EGD Design and Degree Days (DD)

OTS Customer data



OTS-ABC customers are typically mass market customers; OTS non ABC are typically large volume customers
Load monitoring, management and shedding is less viable for OTS ABC customers than OTS non ABC customers.

Targeted Curtailment of Firm Customers who failed to deliver (Option #4)



Curtailment of firm large volume OTS customers from the top 50 customers will provide a significant reduction in demand.

Costs of Curtailment of firm customers – hardware, construction and monitoring

- EGD awaiting response from suppliers on costs for valves and installation.
- Evaluating overhead and operating costs such as system requirements and gas control staffing.

Issue(s) for discussion:

- Gas supply on/off solution conflicts with definition of authorized volumes

* **Authorized Volume:** In regards to Sales Service Agreements, the Contract Demand.

In regards to Bundled Transportation Service arrangements, the Contract Demand (CD) less the amount by which the Applicant's Mean Daily Volume (MDV) exceeds the Daily Delivered Volume (Delivery) and less the volume by which the Applicant has been ordered to curtail or discontinue the use of gas (Curtailment Volume) or otherwise represented as:

CD – (MDV – Delivery) – Curtailment Volume

Bundled firm customer

Eg. 1000-(400-0)-0 = 600 Gj's

*EGD Rate Handbook – Glossary of Terms Part 1, p. 1

Impact of Options	System Reliability			Competitiveness	Ratepayer/ Stakeholder impacts	Term
Options	Firm Transport	Incremental Supply (backstopping)	Load Reduction (curtailment of firm customers)	Impact on Competitive Market	Ratepayer & Stakeholder Impacts	Estimated Lead time
1. Vertical slice	• firm contracts to delivery area	• not required	•not required			2-3 yrs
2. Interim						
a. Board interim resolution	• firm transport to delivery area (Jan-Mar), increasing 10% each yr	• potential option	• potential option			3-6 mths
b. EGD interim solution (modified)	• firm transport (% of MDV) to delivery area (Dec-Mar)	• potential option	• potential option			3-6 mths
c. Direct Energy	• firm transport to delivery area, frozen at 2010 levels	• potential option	• potential option			3-6 mths

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Impact of Options	**System Reliability**			**Competitiveness**	**Ratepayer/ Stakeholder impacts**	**Term**
Options	Firm Transport	Incremental Supply (backstopping)	Load Reduction (curtailment of firm customers)	Impact on Competitive Market	Ratepayer & Stakeholder Impacts	Estimated Lead time
3. Backstopping service	• potential option	• required	• potential option			1 year
4. Curtailment of firm customers	▪ not required	• not required	▪ required			1-2 years
5. Firm Delivery/Financial rating	?	?	• potential option			3-6 mths
6. Short haul build	▪ Firm transport to delivery area	• not required	▪ not required			2-3 yrs

Future Working Committee Meetings

- February 25, 2010
  - EGD’s analysis of Options
  - EGD’s proposal
- March 25, 2010
  - Stakeholder meeting?

ENBRIDGE

Appendix D: Summary of Action Items

From the System Reliability Committee Meeting 2
Held on January 21, 2010

Item	Page	Task	Responsibility
SR2.01	4	CME suggested and others agreed that each option must be evaluated fully for all the incremental costs of the option and impacts to stakeholders.	Enbridge, et al
SR2.02	6	IGUA said that when greater detail is known about curtailment, they would be prepared to survey their members and to provide that feedback to the committee.	IGUA
SR2.03	7	Rather than continuing the discussion on this topic, EGD asked Shell to review the other issues raised on slide 9 and prepare its position on them to be reported to the committee for the next meeting.	Shell
SR2.04	8	The discussion about this chart and particularly the direct shipper component prompted EGD to offer to revise and redistribute the chart breaking out that portion that was direct shipper only, and if possible to further breakout that portion which is Ontario transport service versus western. The purpose would be to better describe the portion of a Design Peak Day portfolio that was related to EGD's request for 90% firm transport. EGD further agreed to include the approximate volumes attached to each of the portions of the chart.	Enbridge
SR2.05	8	After a great deal of discussion involving the entire committee, the group reached a consensus that short haul build would not be considered as an option unto itself, but that it would be subsumed into the considerations of vertical slice and backstopping. It could be an important tool in support of either of those two options. EGD will change charts to reflect this.	Enbridge
SR2.06	8	In response to a question, IGUA added that the split between peaking and curtailment in this tranche was about 60% peaking and 40% curtailment. EGD agreed to try to show that break down on the revised chart also.	Enbridge
SR2.07	9	EGD had referred to an Undertaking that they filed in the hearing that compared contracted capacity to actual flow and DE asked that it be provided to the committee; EGD agreed to provide that. TCPL was asked to layer on additional information including: STFT contracted, STFT flowed, interruptible contracted, and interruptible flowed. EDG added that the committee must also consider the fact that the degree days which were substantially better than EGD's design degree days, 24.8 versus 39.5. EGD also felt that evaluation of flows and capacities should include possible consideration of how TCPL equipment failures could affect capacities.	Enbridge & TCPL

		It was agreed that TCPL and EGD should include the above information in the face of various scenarios of weather and equipment failure. TCPL was finally asked to try to develop the information for the remained of January 2009 also.	
SR2.08	9	Slide 14 spoke to questions about the costs of curtailment but Keith indicated that they were still working on the full costing analysis and that he would report on that in a subsequent meeting.	Enbridge
SR2.09	10	It was suggested that EGD send out an electronic version of this table to allow committee members to add their comments, and then return it to Enbridge, and EGD agreed to do that. EGD offered to provide some additional descriptive details on the slides to assist stakeholders in understand the options.	Enbridge
SR2.10	10	CCC, CME and to some degree IGUA felt it would be difficult for them to fill the table in at this time. CCC suggested they would be more comfortable providing some initial comments now, with the intent of allowing the full committee to discuss all the input in a later meeting. CCC felt that this could generate a “group” response. It was agreed that committee members were free to add extra columns or adapt the table anyway they wanted to feed the next discussion.	Committee Members
SR2.11	10	EGD asked Shell to fill in the boxes for Option 5. Firm Delivery / Financial rating.	Shell
SR2.12	11	As a result of comments received, everyone agree that the committee would place TCPL’s data as the primary agenda item for February 25th, but that analysis of the options would continue in parallel. TCPL agreed to try to circulate their data a week prior to the February 25th meeting.	TCPL
SR2.13	12	He indicated that Keith Irani had volunteered to review each item on the list and summarize how and where it had been dealt with. In the case where the matter has not yet been dealt with, he would indicate that also. That analysis by Keith would be sent to each committee member for their review. If anyone feels that an action item still requires additional work, they will be invited to reply to Keith so that he can address that request as soon as practical.	Enbridge

Appendix E: TransCanada New Capacity Open Season Details Presentation by Lisa DeAbreu

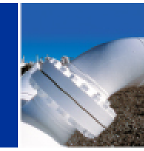
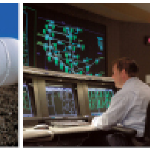
TransCanada New Capacity Open Season Details

Enbridge Reliability Working Committee Meeting

January 21, 2010

TransCanada
In business to deliver

Agenda

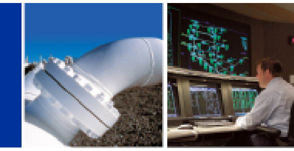
1. **TransCanada Mainline System**

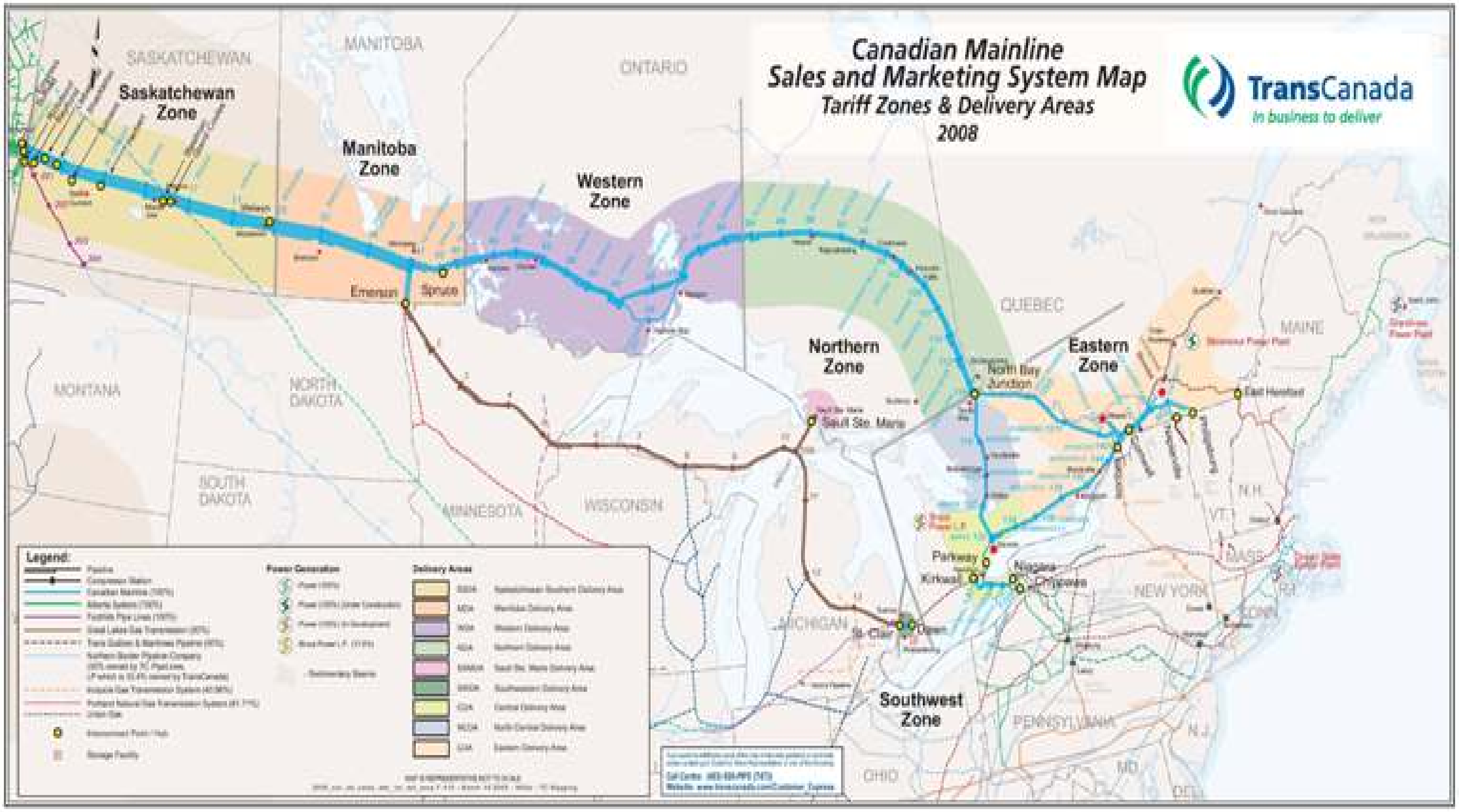
2. **Expansion Capacity**

   - In-service Dates, Capacity, Costs,
   - Requirements for acquiring new capacity

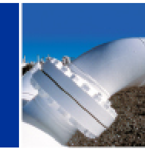
3. **Rule of Thumb on changes in flow**

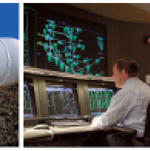
TransCanada Mainline





New Capacity

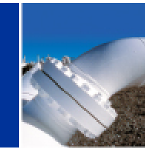


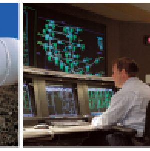


- **Expansion Capacity out of Parkway**
  - Earliest in-service date Nov 1, 2012 for expansion facilities
  - Facilities
    - Phase 1 – 10 km of pipe, 148,000 GJ/d, $55 million
    - New Compressor – 89,000 GJ/d, $32 million
    - Phase 2 – 10 km of pipe, 234,000 GJ/d, $70 million
    - Phase 3 – 30 km of pipe, 820,000 GJ/d, $145 million

TransCanada

New Capacity Requirements

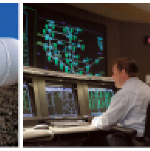




- Bid into a New Capacity Open Season
- Backstop construction of new facilities
- 10 year FT contract
- Use of Integrated System

TransCanada

Toll Impacts



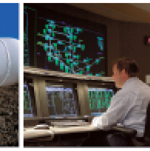
- **Parkway to CDA build could put upward pressure on tolls if the firmed up quantities replaced discretionary short haul capacity.**

- **Parkway to CDA build could also put upward pressure on tolls if the firmed up quantities replaced a mix of long haul discretionary during the peaks and short haul discretionary used during the non-peak periods.**

- **Incremental +/- 100,000 GJ/d of long haul flow *(not capacity)* equals approximately -/+ 8 cents to the Eastern Zone toll (based on 2010 inputs and all other things equal).**

TransCanada

Toll Impacts



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TransCanada

ENBRIDGE

Working Committee Notes

Enbridge Gas Distribution Inc.
Working Committee Meeting 3
On
System Reliability

February 25, 2010
L&L Boardroom
Enbridge Gas Distribution
Consumers Road
Toronto, Ontario

Prepared By:
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Putting the Pieces Together

Table of Contents

Enbridge Gas Distribution Inc.
Working Committee Meeting 3
On
System Reliability

1. Opening and Introductory Remarks

Presented by Bob Betts, Facilitator

The meeting was called to order at 9:20 a.m. Bob Betts welcomed all those in attendance.

He acknowledged the presence of some new participants and after introducing himself asked all in attendance and on the telephone to introduce themselves. The new people at the meeting were:

- Steve Emond, TCPL
- Zafir Samoylove, TCPL
- Ken Schubert, TCPL
- Jim Bartlett (via telephone) TCPL
- Lawrie Gluck, Ontario Energy Board, and
- Kent Wirth, Enbridge.

Following the introduction of TransCanada, Bob explained that they were here to deliver a substantial presentation in response to questions from this committee about system reliability in the Enbridge franchise areas and the potential risk of capacity shortfalls. Bob indicated that the presentation and associated questions could take up to three hours which will force some changes to the agenda. He had contacted both Ric Forester and Paul Dumaresq who were scheduled to make some form of presentation today and both had said that the TransCanada presentation was very important and that it should be allowed to take its full course. They both indicated their willingness to postpone their presentation if that was necessary. The group agreed that we would deal completely with the TCPL presentation and then determine what we would do next.

Bob then reviewed the most notable events and activities that have occurred since the last meeting on January 21, 2010.

- The January 21st Notes were distributed and posted as has been the past practice;
- Enbridge distributed a Summary of the November 20th Action Items with a status update, Bob indicated that Enbridge would appreciate any comments on that summary;
- Enbridge provided a response to SR2.07 “TCPL Deliveries to EGD – Peak Day vs. Peak Day 2009 Actual;
- Enbridge provided a response to SR2.04 and .06 showing the EGD Design Peak Day Portfolio; and

- EGD issued Guidelines for Populating the Options Matrix. On this action item for committee members, Bob indicated that there was very a poor response and that Enbridge needs additional feedback from stakeholders, particularly on impacts.

2. System Reliability Plan Going Forward & System Reliability Nature of the Application– Malini Giridhar/Bob Betts

(Starting on Slide 3 of the Presentation included in Appendix C)

Before moving to the TransCanada presentation, Bob indicated that there were still questions about the timeline for the processing of this issue before the OEB and the nature of the application that Enbridge believed it would be making. He stated that this presentation was planned to be made by Malini Giridhar and Norm Ryckman, but that Norm had to attend to an OEB matter at the Board office this morning. Bob had met with Norm the day before this consultative and Norm asked Bob to relay his comments to the committee on his behalf.

Malini opened by reviewing Slide 3 highlighting the following key dates:

- Feb 25: TCPL Presentation and Further discovery and consideration of options
- Mar 25: Final Discovery Phase and Initial discussion of all party positions – Enbridge and all parties
- Apr 13: Enbridge presents its preferred position and Consultative discussion about how to proceed, either: Begin settlement phase, Report back to larger committee, or both (This could be done in a face-to-face meeting or by circulating a position document.)
- Apr 22: Settlement negotiations; report to consultative, other?
- May 20: Continued negotiations, if required.
- June 30 (or as soon as practical): Enbridge files application with the Board (separate or within some other application?) Malini indicated that they could not be 100% certain about the timing of an application because it was linked to the outcome of this consultation process.

Bob Betts added to the final point by saying that Norm Ryckman indicated to him and Malini confirmed that this matter and the matter of Mass Market Unbundling will definitely be put before the OEB, in one form or another, for the Board's consideration of both issues.

Bob moved on to Slide 4 "Nature of the Application" indicating that the package that would be presented to the Board will include:

- The meeting notes
- Enbridge's assessment of need
- Enbridge's review and assessment of alternative resolutions, including impacts
- Enbridge's requested resolution

He also indicated that Enbridge is still hopeful that a consensus will be achieved on both the system reliability and the mass market unbundling issues which would allow for a significantly different application, than one based upon a partial settlement or no settlement at all.

Bob added that if a consensus if not possible Enbridge is certainly hoping that the committee can agree upon a narrowed list issues, to assist the Board in the review of both System Reliability and Mass Market Unbundling.

3. Enbridge Working Committee on System Reliability – TransCanada

The committee now moved to the presentation by TransCanada presented in parts by TCPL personnel:

- Steve Emond, Vice President, System Design & Commercial Operations
- Zafir Samoylove, Senior Engineer, Operations Planning
- Ken Schubert, Senior Business Analyst, Customer Service Projects

3.1. Introductory Slides & Overview of Risk Factors - Steve Emond, Vice President, System Design & Commercial Operations

The first point emphasized by Steve in his presentation was that the Enbridge service areas are affected by several upstream transporters, not just TCPL. While discussions have been largely focused on the TCPL system, Enbridge's supplies could also be severely affected by transportation problems on Union's system, Great Lakes Gas Transmission ("GLGT") and Vector. Unexpected problems on any of the four upstream pipelines could affect system reliability for Enbridge customers and all customers downstream of Enbridge.

Moving to slides 4 and 5, TCPL emphasized the fact that while Enbridge depends on TCPL for approximately 1 million GJ/day firm for its CDA and EDA, it relies on Union's Dawn to Parkway and Dawn to Kirkwall for over 2.2 million GJ/day. In other words Union is relied upon for the supply of 68% of the Enbridge franchise area supply versus only 32% reliance on TCPL. In addition to that dependency on Union's system, TCPL also holds firm capacity on Union's system for over 1.8 million GJ/d for its customers. The implication of this is that while a major restriction on TCPL could have a serious affect on system reliability for Enbridge's franchise areas, the effect of a major problem on Union's system could be as serious or potentially more serious.

Using slides 6 and 7 Steve went on to describe another way of moving gas from Dawn to Enbridge's CDA and EDA, as well as points downstream. That was "by displacement" which was a notional movement of molecules northwest around the Great Lakes using GLGT to Emerson and then east again via TCPL.

Steve now moved on to Slide 8 describing TCPL's service or supply priorities.

The contracts ranked from the highest to lowest as supply priorities are as follows:

1) Firm contracts including: FT, STS, STFT, and Upstream Diversions
2) Downstream Diversions
3) Interruptible.

TCPL's tariff terminology defines an Upstream Diversion as an alternate delivery point along the firm contract path, where Downstream Diversion as a delivery point outside or beyond the firm contract path.

These priorities come in to play when demand exceeds capacity and when "bottlenecks" occur in the system forcing curtailment of some contracted volume. Interruptibles are the first to be curtailed, firm contracts are the last.

This slide led to a question from Board Staff and a discussion about bottlenecks. Steve provided additional detail saying that the locations of bottlenecks vary along the system from day to day and season to season. A bottleneck is defined as a condition when demand exceeds capacity, and can therefore result from either unusually high nominations into an area or from pipeline restrictions. High demands are normally associated with colder that planned weather conditions, seasonal movements into storage areas, and/or market conditions, while reduced capacities are normally associated with failure of the system or its components to perform to design capacity levels.

Board Staff continued with a question regarding where these bottlenecks occur and whether they commonly occur in certain locations. TCPL indicated that while they can occur anywhere they often reoccur in certain areas such as the northern Ontario line, Iroquois in the EDA in the winter, into the Dawn storage area in the summer when rebuilding storage inventory, and often in the EDA in the summer when New York state generator demands create attractive market pricing conditions.

In response to a further question, TCPL indicated that bottlenecks in the CDA are not very common but have occurred, while bottlenecks into the EDA occur relatively frequently, quite often due to high downstream demands.

TCPL reminded everyone at this point that bottlenecks caused by high demands only occur when nominations come in beyond the level of firm contracts. Firm contracts are always assured delivery, except in the case on an extremely unusual capacity restriction. Steve Emond could recall only a couple of occasions in his many years with TCPL when firm contracts were curtailed by any failure in the system. The exposure to curtailment really lies in the discretionary contracts, non-firm or interruptible contracts.

The TCPL team identified another problem for interruptibles customers by focusing on the Eastern Delivery Area (EDA) shown on Slide 9. In a scenario where there is a localized restriction on one of the lines in the EDA, for example a restriction on the Ottawa line. In this case discretionary nominations, such as STFT or interruptible transportation could be turned down even if there is sufficient capacity in some other part of the EDA, such as the Montreal line. This is because TCPL could not be certain where that gas would go to, and would not further compromise their ability to deliver on their firm commitments.

IGUA asked about how gas would physically move compared to the contracted receipt point and delivery point using Empress to Iroquois as an example. TCPL replied that they would choose the safest and cheapest path for the gas to take based upon the receipt and delivery points. IGUA followed with the point that to fully evaluate capacity one needs to consider all available parallel paths and TCPL confirmed that they evaluate capacity between two points by considering both capacity and bottlenecks on all the available optional paths.

TCPL summarized the discussion about risks associated with large Distributor Delivery Areas (“DDA”s) on slide 11 by noting:

- Contracts, nominations, capacity allocation are done on DDA basis
- Localized outages or bottlenecks affecting any part of the DDA will result in restrictions to the full DDA , for example an outage on the Barrie Line or the Niagara Line would affect flows down into the GTA
- When restrictions or bottlenecks arise, TransCanada would restrict deliveries (based on Tariff service priorities) to all of the Enbridge, CDA including the Niagara Line
- Large DDAs spanning large geographic areas and multiple segments of the TransCanada System are more likely to be impacted by outages.

In response to questions from Board Staff and IGUA, TCPL commented that currently, gas flows from Canada to the Northeastern US, but there is more and more interest in potential movements from the Northeastern US to Canada.

Moving on to slide 12, Steve emphasized the point that TCPL does not build, nor reserve capacity or facilities for STFT, Diversions, alternate receipts or interruptible service, all defined as Discretionary Services. They only build and reserve for long term firm (FT) and they define long term firm to be 12 months or longer. Steve clarified that STFT is prioritized as “discretionary” until the nomination is accepted, at which point it would be prioritized as “firm”.

Not only are Discretionary Services not planned for, they are also subject to other restrictions not effecting firm contracts, including:

- Efficiency measures (e.g. compressor unit retirements),
- Incremental Firm Contracts (e.g. power generation),
- Other uses (e.g. Keystone),
- Planned maintenance

On the matter of planned maintenance, IGUA suggested that the OEB’s concern about reliability could be improved if TCPL provided notice of planned maintenance particularly during peak day conditions. TCPL indicated that they would not be performing planned maintenance during peak day conditions that would jeopardize their ability to deliver their firm contracts. They cannot plan for unexpected breakdowns or failures at any time, they just happen, and usually under the most extreme conditions. After a series of questions by IGUA, TCPL indicated that they currently provide some notice of non-critical maintenance, but they would consider the merits of formalizing and expanding the notice provision policy. Direct Energy supported TCPL performance by adding that they never have problems arising from insufficient notice from TCPL and Enbridge agreed with that point.

Another question was asked about how there could be excess capacity, if TCPL designs their system based on firm long term commitments. TCPL provided a number of reasons and causes for this excess, including:

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(Div of R. J. Betts Enterprises Ltd.)

- Their design capacity includes a contingency for loss of their most critical unit in the system;
- Shippers don't always elect to nominate their firm contracts;
- Competitive paths may come into service, such as Alliance;
- Non-renewals of firm commitments;
- Peaking service provided by non-firm contracts;
- Sometimes commitments made during the design phase change over time, as an example the Enbridge delivery area previously was fully contracted firm, but now it has a very large portion of discretionary deliveries, while the delivery volumes may not have declined that much, it all shows up as excess capacity because it is not firm, i.e. FT, STS, STFT, etc.

When TCPL recognizes that actual flows are below the design capacity they prudently begin to make cost-effective changes to the pipeline system to reduce the capacity in alignment with current long-term firm commitments.

In response to a question from Shell about TCPL's ability to reinstitute some of those capacity reducing system changes, TCPL said that if firm commitments began to grow they could begin to make modifications to their system to bring back capacity, but if something sudden happened like a failure in the Union system, they could see capacity demands go up to their original design capacities for a few days, but they would not be able to react to that situation.

TCPL moved now to slides 12 and 13 reviewing the heightened risks associated with extreme days and extreme conditions.

Steve started by indicating that because TCPL is operating well below its original design capacity it has shut down dozens of compressors, leaving compressors and valves sitting idle. When demand spikes, particularly in extremely cold weather TCPL typically experiences compressors failing to start and frozen recycle and isolation valves. Compounding that, these idle pieces of equipment are often in remote geographical areas making quick maintenance response difficult, if not impossible to guaranty.

Taking a look at the January 2009, those extreme weather days saw frozen valves, units failing to start, many unplanned outages (8 on the Northern Ontario Line and 5 on the Prairies Line).

The volatility associated with sudden weather changes bringing gas fired generators and heating furnaces on-line exacerbates the problem. It is very difficult to go from low flow to high flow in an extremely short period of time.

IGUA asked if TCPL had any work programs aimed at addressing risks of equipment failure to perform and TCPL said without firm contract commitments there is no prudent justification for spending capital to provide added assurance to non-committal discretionary shippers. Even in the January 2009 situation, TCPL was able to satisfy all of its firm commitments. The problem was a lack of discretionary capacity.

Steve's final slide 14 focused on two "extreme Condition" questions:

1. Under extreme conditions will capacity be available?

2. If capacity is available how much will be accessible to Enbridge's distribution areas?

Under each he made these points:

1. Under extreme conditions will capacity be available?
   a. There will likely be outages from compressors failing to start and other equipment function leading to a reduction in any discretionary capacity and potentially even a proration of firm capacity;
   b. All shippers with firm entitlements will certainly nominate fully, not leaving any left over for discretionary use.

2. If capacity beyond commitments to firm shippers is available, how much will be accessible to Enbridge's distribution areas?
   a. Referring back to the service priorities listed on slide 8, if excess capacity is available it would first go to upstream and downstream diversions by firm contract holders;
   b. The Enbridge delivery area would be competing with other markets, both upstream and downstream for any discretionary capacities on TCPL or alternative pathways.
   c. Allocation of new interruptible nominations and new STFT contracts is done on a "sealed-bid auction process", which means that a shipper, such as Enbridge, wanting extra capacity would not know whether they were successful in the bid for a particular service delivery package until after nominations close. This means you can't just keep out-bidding others until you get what you want at any price.

IGUA asked if the issues associated with the sealed-bid auction couldn't be resolved by going to the open bid auction. TCPL responded by saying that apart from the process being well established in the tariffs, there are practical reasons why the seal-bid works better than an open-bid auction including:

- The fact that bids come in on a variety of service options, different receipt points, delivery points and paths, different services such as STFT versus IT, different volumes, etc. Price is only one of the bid components;
- The need to have bidding end at a point in time to allow the bids to be analyzed, evaluated and implemented as contracts;
- After the auction closes the nominations are fed into an allocation model to determine the best arrangement of nominations to accept;
- Nominations determined to be successful on one line might affect the suitability of nominations requiring that line, or even the use of another line.

Morning Break

3.2. Capacities on TransCanada – Zaf Samoylove, Senior Engineer, Operations Planning

Zaf Samoylove began this portion of the TCPL presentation focused on "Capacities on TransCanada" following the morning break.

In this discussion, Zaf first reminded the group how TCPL designs its system to meet capacities, he said:

> ***TransCanada designs its system to meet the daily contract quantity specified in long term firm contracts (FT, STS, FT- SN) during periods of peak demand even with loss of the single most critical compressor unit.***

He paraphrased this by saying that TCPL can meet its commitments to long term firm quantities with any one compressor out of service; however, TCPL makes no commitment in its design to ensure delivery of discretionary quantities such as interruptible or other potential non-contracted quantities.

It was pointed out here again that TCPL does not design using "degree day" criteria. Zaf indicated that unlike distribution utilities, TCPL's geographic coverage is very expansive and there is never a single degree day condition affecting its customers.

Definitions in use in his presentation include:
"All facilities" = no planned maintenance or unplanned outages
"Firm" = Design conditions; loss of critical unit

The first capacity slide 18 showed the capacities, amounts contracted and available capacity on TCPL's Northern Ontario Line as well as its TBO (Transportation By Others representing the transportation capacity contracted on other pipelines to transport gas for TCPL customers) on the alternate paths of GLGT and Union (both M12 to Kirkwall and Parkway). This slide showed that capacity exceeds long term firm contracts in the 2010/2011 winter period, both with all facilities functioning and with the loss of the most critical compressor unit.

Slide 19 illustrated the available capacities to the CDA and the EDA (Enbridge, GMI, Iroquois, etc.). It showed that any available capacity on the Northern Ontario Line could be delivered to the CDA, available capacities to the EDA and export were less than half of the capacities on the Northern Ontario Line.

Slide 21 showed Enbridge's Peak Day demands on the TCPL system in both the CDA and the EDA, and the portions underpinned by firm contracts ("contracted quantity") versus the quantities not underpinned by firm quantities ("exposed quantity"). Malini pointed out that the 1900 TJ shown as Enbridge's Peak Day Requirement included approximately 130 TJ of curtailment volume. Malini said it was not removed because the current trend for curtailment customers is to bring in Curtailment Delivered Supply ("CDS") quantities and then continue to consume gas supply rather than curtail their consumption.

A discussion on this item concluded that it is an item that needs to be considered in the system reliability issue. Shell suggested that perhaps curtailment customers should be made to declare their back-up for curtailment volumes. Direct Energy asked Enbridge if they could determine what percentage of volume to the CDA was firm. He defined firm in this context as Ontario T Service where direct shippers would not have turned back their capacity. Enbridge said they could do that.

Continuing with slide 21, Zaf pointed out that in Enbridge's CDA 716 TJs are currently considered exposed by TCPL and in the EDA 144 TJs are exposed. Exposed meaning not unpinned by firm contracts with TCPL.

Zaf indicated that the next group of slides would run through various capacity scenarios for Enbridge's CDA and EDA, including:

1. All facilities – Max Daily Capacity (all facilities available)
2. Firm - Design Condition (loss of single most critical unit)
3. Multiple Unit failure – 600 TJ impact (the January 2009 incident)
4. Multiple Unit Failure and Line Break – 1770 TJ impact (the September 2009 line break, adjusted to cold winter weather facility failure)

3.2.1. <u>Design Capacity Scenario based on Peak Day Demands</u>

The first scenario on slide 23 is based upon downstream shippers, i.e. shippers east of Enbridge's CDA taking all the volume that TCPL can provide into their areas. That would be common in a period of extremely cold winter weather, such as the January 2009 situation.

In this scenario there would still be available gas to the CDA even under the Firm Design condition with the most critical compressor out of service.

In response to a question, TCPL confirmed that in addition to Enbridge the committee had to remember that Union, Niagara, the WDA and the NDA would all be competing for this capacity.

In this Peak Day scenario, even with TCPL's most critical compressor out of service, the model shows that there would not be a system reliability concern in the CDA, as long as CDA shippers were able to compete successfully for the gas.

Slide 24 shows a scenario with similar conditions to the previous, except in this case the CDA would contract for all NOL (Northern Ontario Line) capacity it can take. In this scenario there would be no capacity left for the EDA beyond the volumes previously contracted as firm.

TCPL admitted that this has not happened because shippers in the EDA are usually able to compete successfully for some portion of the available NOL capacity. TCPL presents these two scenarios as the "bookends" between which the actual results will fall.

In considering these two scenarios as the extremes or the bookends, Enbridge reminded the group that Enbridge currently builds its Peak Day design based upon a 39.5 degree day, and noted that they have had a 44 degree day in 1994. Based upon today's customer numbers a 44 degree day occurrence would add another 350,000 GJs to the peak. Furthermore, since the peak day is based upon average wind conditions, if wind conditions were at 25 mph versus 9 mph, Enbridge could take an additional 300,000 GJs.

Slide 25 rounds out the presentation of the peak day scenario by indicating that that Enbridge's EDA is not only dependent upon how much available capacity the CDA takes, it is also competing with other EDA nominations and exports for any gas coming from the west, which could in itself consume all available capacity.

3.2.2. A 600 TJ NOL Reduction (the Jan 2009 scenario) and Peak Day Demands

In this scenario outlined on slide 27, if the EDA took the remaining available capacity off the NOL then there would be insufficient available capacity on the Northern Ontario Line to cover Enbridge's exposed or non firm requirements of 716,000 GJs. Capacity would fall 34,000 GJs short of demand.

Shell asked TCPL if the 716 TJ noted as being exposed, was instead contracted firm would the problem not still exist. TCPL answered that if the 716 was contracted as firm, TCPL would have operated its system to deliver that amount even with a critical component out of service. That would have had system components up and running and thus avoided much of the startup issues that created the problem.

3.2.3. A 1,700 TJ NOL Reduction (the Line Break Scenario) and Peak Day Demands

In slide 28, the 1770 TJ reduction assumed for this scenario was the actual reduction associated with the line break that occurred in September of 2009, which occurred by good fortune in a low volume period for TCPLs Northern Ontario Line.

In this scenario, shown on slide 28, TCPL assumes that the EDA market would take everything that was available. This situation would leave the CDA with no available capacity and therefore no volume beyond the amounts that were contracted as firm.

This scenario shows that if the line break that occurred in September 2009, had occurred on a Peak Demand Day, neither the CDA nor the EDA would be able to receive its peak day requirement from TransCanada, and in this event the shortfall could be 716,000 GJs in the CDA and 144,000 GJs in the EDA.

Board Staff asked how long it would take to make a repair to the line, and TCPL responded by saying that the line break in the fall took about a week to repair. Board Staff then said that being without capacity in the cold part of the winter for a week would be disastrous. TCPL agreed, but once again reminded everyone that it would only be volumes that were not underpinned by firm transport that would be facing that problem.

Because of the sudden shut-down, TCPL would have immediately ceased offering STFT and no shipper would have been able to nominate additional STFT to secure their supplies.

Enbridge put this shortfall of capacity into perspective by saying that a shortfall for 716,000 GJs would affect approximately 700,000 residential customers. When reminded about a $12 million estimate for restart costs, Enbridge indicated that estimate was based upon only 100,000 customers.

Enbridge highlighted another issue with its direct shippers moving away from FT underpinning particularly in light of Union North and GMI remaining backed up with FT. If all were equally exposed to discretionary volumes they would all receive a prorated share, but under current circumstances Union North and GMI would receive all of their firm nominations and the Enbridge franchise would have to deal with the shortfall.

Enbridge explained that they are obligated to manage a small amount of shortfall and that even their TCPL contract allows them leeway of 2% overage; however, after that Enbridge would be required to shed load, and in this case, the higher the amount of shortfall, the more customers would be cut-off from their gas supply. As Enbridge said at an earlier meeting, if there is no resolution found to the lack of sufficient FT underpinning peak day requirements, then there will be a requirement to develop an approved plan to shed load, or cut gas flow to customers. Even those that are paying for and expecting firm service.

Enbridge was asked how they would physically and operationally shed load to the extent that this scenario would require. Enbridge replied that they would definitively look at large users, but they recognize the only way to deal with these volumes is to isolate delivery areas within their franchise and shut-down supply to those areas. These could include small and medium size municipal franchise areas.

Shell asked TCPL what would happen if all of Enbridge's non-firm was firmed up. TCPL said that all shippers would be reduced on a prorata basis, still leaving Enbridge's share of the shortfall at about 70,000 GJs. When asked if a 70,000 GJ shortfall is as bad as a 716,000 GJ shortfall, Enbridge reacted by saying that the size of the shortfall is absolutely critical, they would be able to manage the smaller amount much more reasonably than the large amount. For example, when gas is shut off every household must be started back up on an organized basis ensuring that all appliances are off and valves closed before the gas flow resumes and then going into each property to relight appliances, there are only so many gas fitters available to perform these functions. Restarting 700,000 customers as a result of a 700,000 GJ shortfall could literally take months to accomplish and many millions of dollars. On the other hand 70,000 GJs could be focused on a very few large users.

The final slide on this scenario, slide 29, showed the other "bookend" in which the CDA got all the capacity they were able to get leaving the EDA the rest. In this case both the CDA and the EDA would face a shortfall, of 281 and 144 TJs respectfully. Both Enbridge's delivery area would face gas flow shut-downs, to the extent that they were not covered by firm transport.

3.2.4. Capacity Scenario Summary

Slides 30 and 32 summarized the results of this excess capacity exercise.

- If all facilities are available:
    - o Discretionary capacity would be available to Enbridge CDA & EDA, but they would have to compete for that capacity. This is a greater issue for the EDA.

- Under TCPL's firm design conditions i.e. with loss of critical unit
    - o Less capacity is available to Enbridge CDA & EDA and both must compete for any capacity

- On an extreme day, there will be an impact on non-firm services
    - In a Jan/09 type restriction (600 TJ capacity loss): CDA could be restricted
    - In a Sept/09 Line Break restriction (1,770 TJ capacity loss): both CDA & EDA could be severely restricted

TCPL left the committee with one additional scenario asking what would happen if Union encountered a major failure like a line break, with a potential reduction of 2.5 Bcf?

TCPL indicated that it could not establish a probability of an outage, since there is insufficient data on starting multiple units in extreme weather; however, they were able to say this:

- If the outage occurs during an average day:
    - o The impact on deliveries may be minimal (or none in the case of the Sept 09 line break)

- If the outage occurs during periods of extreme cold weather:
    - o The impact on deliveries can be significant
    - o There is increased likelihood of facilities failing

- If any outage occurs:
    - o Non-firm discretionary services would be cut to zero before any firm services are impacted; and
    - o If firm is impacted, such cuts would be made on a prorata basis.

Lunch Break

3.3. January 2009 Cold Snap – Ken Schubert, Senior Business Analyst, Customer Service Projects

Following a brief break for lunch, Ken Schubert moved to the third major portion of TCPL's presentation answering the committee's questions regarding the details of the January 2009 Cold Snap and the resulting supply issues.

Slides 33 through 35 set the operating environment facing TCPL approaching and during the Jan 2009 Cold Snap.

Slide 33 – General Operating Environment

- The pending cold weather caused demands to go up well above normal conditions:
- Long haul STFT was sold out;
- Deliveries to all of the EDA was approximately 3.1 Bcf plus exports downstream of the CDA had very high deliveries;
- Reduced Overrun Service on Union increased flows on the NOL (Northern Ontario Line);
- System Bottlenecks ("nominations in excess of capacities") appeared in multiple locations:
    - East Hereford at capacity,
    - Chippawa at capacity – New record for deliveries,
    - Prairies Line restricted on the 14th of January,
    - GMi's EDA at capacity on the 15th,
    - NOL at capacity and restricting on the 15th and 16th.

NOTE: Despite these conditions all Firm Services were met, only non-firm and discretionary were affected.

Slide 34 – Conditions on the Prairie Line (Empress to Manitoba)

- Extreme cold temperatures across the Prairies
    - -35C in the west
- TCPL Actions
    - Cancelled 3 planned outages ~ 60 MW
    - Started 14 compressors totaling ~ 210 MW
- Impact of extreme weather on the Prairies Line
    - 5 unplanned unit outages
    - Several units failed to start
    - Frozen recycle valves, frozen isolation valves…

Slide 35 – Conditions on the Northern Ontario Line "NOL"

- Extreme cold weather across the Northern Ontario Line
    - -43C in Northern Ontario
    - -31C in Ottawa
- TCPL Actions
    - Expedited completion of 3 outages ~ 80 MW
    - Started 18 compressors totaling ~ 400 MW
- Impact of extreme weather on the Northern Ontario Line

Prepared by Regulatory Support Services
(Div of R. J. Betts Enterprises Ltd.)

- o 8 unplanned unit outages – reduced capacity by approx. 600 TJ/d
- o Several units failed to start
- o Frozen recycle valves, frozen isolation valves…
- o Effect of outages compounded by geographic proximity to maintenance staff

AEGENT asked why the compressors couldn't be started ahead of the need, in anticipation of higher demands. TCPL provided two reasons: first that the compressors are brought up based upon the system operator's view of the changing demand situation and the appearance of bottlenecks and restrictions, second, the compressors cannot be brought on line until the demand exists and the flow is there, in their service area.

Slide 36
In presenting this slide, TCPL noticed that there was a graphical error in that the bottom two lines- "TransCanada's Authorized Transport on Union (M12)" and "TransCanada's Firm Entitlement on Union (M12)" were both shifted one day to the right. TCPL said they would correct the slide and redistribute it later.

TCPL went on to address the key points on this slide during the cold snap in the middle of the month:

- Discretionary nominations were not available on Union's M12 line, causing TCPLs NOL to pickup additional flows;
- Union's M12 line continued to deliver its firm commitments and its needs to its distribution customers.
- Nominations began to shift away from discretionary service in favour of STFT to ensure delivery
- Capacity on the NOL declined below Design Capacity and there was no capacity available.

On Slide 38 depicting nominations in January 2009 in the CDA, TCPL pointed out how STFT grew, diversions and ARPs (Alternate Receipt Points) diminished and interruptible declined to virtually zero in the mid-month.

TCPL responded to a question by IGUA saying that TCPL was sold out of capacity in this area for a few days starting about the 18th. Because there is a requirement to contract for STFT two days ahead, this would mean that on January 16th, it would not have been possible to nominate STFT shipments on the 18th. The 15th was when the nominations became tight and interruptibles began to disappear.

TCPL reminded everyone that when a sudden, unexpected restriction occurs like a line break, the opportunity to nominate STFT disappears very quickly. For example if TCPL had a line break they would remove that capacity as soon as it happened and therefore nominating two days ahead, after you hear of the break would do no good at all, because the capacity would already be off the table.

Shell asked Enbridge if they were able to manage shipments during this period and Enbridge confirmed that their customers did not suffer during this period; however, there was one worrisome moment on January 15th when approximately 70,000 GJs of deliveries for the EDA could not be confirmed in the timely window, however, later that day they were confirmed. Enbridge indicated that there were three suppliers in the CDA and one in the EDA that were not able to have confirmation in the Timely Window, however, all did have confirmation before the end of day, two in intraday 1 and the other in intraday 2. Enbridge went on to say that these suppliers have contracts to supply peaking service to Enbridge and also service to the direct shippers. They would have the option to show this shortfall in whatever service was most cost effective. In this case, of the three suppliers who fell short in the CDA, two showed the shortfall in peaking service and one in CDS. All decided to ensure that shipments to direct purchasers were delivered as per contract.

This experience has led Enbridge to a concern that the peaking service commitments are being underpinned by interruptible supply and therefore not dependable in extreme conditions.

Enbridge reminded the committee that had the deliveries failed to materialize, the next morning they would have been faced with the question of where and how to shed load or cut customers off since that is their only remedy. Unlike Union, they cannot start-up a compressor or access storage to resolve such a shortfall, they can only shed load.

TCPL pointed out that this January 2009 cold snap was still about 5 degrees short of Enbridge's Design Day conditions. Had colder temperatures be present, there could very well have been a shortfall.

Slide 39 highlighted how diversions, both upstream and downstream were affected by the bottleneck, with no diversions being authorized through the bottleneck area. This was based on activity at the Timely Nomination Cycle and acknowledges that the nominations could have been authorized in later windows.

There was a significant discussion around the direct shippers' responsibility to deliver only their MDV or Mean Daily Volume. Based on that requirement, in a scenario displaying 5 degree colder temperatures, the direct shipper would not be required to deliver anymore gas according to the terms of their contracts. That reality would suggest that a solution to an extreme day shortfall would have to include additional firm peaking capacity or CDS. Enbridge restated that it is the supplier's choice where they show a failure to delivery, i.e. to direct shippers or peaking, or other, and they will make that decision presumably for economic reasons. The real issue is that the problem exists because of a lack of sufficient FT underpinning the supply to the Enbridge franchise area, and there are several supply alternatives where additional FT could and/or should be required. Enbridge's concern about direct shippers failure to deliver comes from the interruptible service underpinning of their nominations, and in the event of a major problem on a pipeline, the likelihood that direct shippers would not be able to deliver their MDV due to cancellation of interruptible supply.

Shell suggested that Enbridge could incent suppliers to honour their peaking service contracts by including a penalty which is stiff enough to match any economic market benefit to diverting it to another market. Many acknowledged the difficulty associated with creating and monitoring penalties levels to ensure they always incent such behavior.

TCPL was asked what would have changed in the Cold Snap scenario if Enbridge's franchise had additional 200,000 GJs of FT. TCPL said that the capacity would not have changed, but Enbridge's customers would have been secured, there might have been further restrictions on diversions, and there probably would have been less STFT available for nominations.

This led to another question asking TCPL is they felt that they were not offering sufficient incentive to use FT service, or conversely if they are not making their more dynamic alternatives too appealing, thus adding to volatility in terms of delivery. TCPL felt that the volatility is not so much a function of their service as it is a function of the number of pipelines, the wide area influencing shipments and dynamics of the various markets.

TCPL closed the discussion about the January 2009 scenario by saying that this was a real life event and while fortunately no one suffered, what would the next one be like, would there be greater capacity restrictions, and would there be colder weather? We must learn from and adapt to this potential for concern. Too much reliance on interruptible and other non-firm alternatives makes Enbridge vulnerable to export customers and other downstream markets.

The discussion continued around the circumstances of January 2009 and what could have happened if the temperatures had been colder. Enbridge confirmed that in the January 2009 event, direct shippers met their delivery requirements, probably by contracting STFT as suggested by the significant increase in STFT during that period. Enbridge indicated its concern that those STFT nominations may not have been available or successful if the duration of the outage had been extended, or if the 600 TJ outage had have been greater, or if the outage had have been apparent to TCPL earlier and they reacted by reducing availability of additional STFT.

In response to a question from AEGENT, Enbridge said that under peak day conditions it would have relied on bringing additional volumes in from Dawn and called on more peaking to support demands in the CDA; however, acknowledging that peaking supplies and CDS are not based on FT contracts means that in severe conditions, it would be possible that peaking and CDS could also have been curtailed, leaving Enbridge short again.

Direct Energy made the point that if the degree days had have been higher perhaps by 5 degrees, there would have been a system reliability issue, but it would not have been due to the fault of the direct purchase sector because the requirement to provide only a mean day volume "MDV" would not have provided any additional volume; in that case, any shortfall would been due to insufficient peaking service and CDS. Enbridge agreed that the issue of system reliability involves peaking and CDS, as well as direct shipper use of interruptible services, particularly since the same suppliers provide all 3 kinds of supply.

Enbridge added that direct shippers strategies to use lower cost interruptible service until the week-ahead weather forecasts cold temperatures worked in the January 2009 situation, but will it always work for example if the restrictions exceed 600 TJs or if the cold weather snap lasts for two weeks instead of one week, or if restrictions occur as a result of a sudden system breakdown? Enbridge said that firm transport needed to be considered for peaking supply, CDS and Direct Purchase

Enbridge indicated that in the next session they would like to expand the review to include a closer look at the firmness of Peaking Service and CDS, and the role they play in the system reliability question. Shell agrees that the committee needs to take a closer look at Peaking Service and CDS.

TCPL's final slide #40 in this series highlighted the jump in STFT nominations for cold week in January 2009, by showing the same spike occurring in the Union CDA. In this case, the Union system had adequate capacity to supply the additional nominations.

3.4. Capacity & Service Options to Serve Enbridge Markets – Steve Emond

At this point, Steve Emond summarized TCPL's view of the options available to Enbridge for consideration in this consultation.

FT from Empress is obviously the least Risk arrangement

- Lots of capacity available
- Excellent supply availability

STFT from Empress is still a very Low Risk, if contracted for full winter (November to March, before November))

- Lots of capacity available if contracted before extreme day
- Excellent supply availability
- Greater risk if based on a week-ahead weather forecast

A discussion ensued about how early nomination of STFT can protect shippers against major outages like line breaks. TCPL commented that if a line breaks, they would reject any additional STFT nominations so those on interruptible would be unable to firm up their supply; however, parties with STFT already contracted are treated like all other FT customers and get their volume before interruptible and downstream diversions. If the restriction is severe enough involve firm contracts STFT would receive the same prorata benefits as all other firm shippers.

FT or STFT from North Bay

- Supply availability? Need partner with upstream firm transport.
- Not a liquid location in itself

FT or STFT from Dawn

- Capacity may be available
    - Subject to backhaul/exchange….with flow through Northern Ontario Line

- Backhaul would be backed by firm transportation on TCPL.
- Good supply availability

Upstream Diversion
- Capacity is “firm” for upstream diversions
  - Example:
    - Diversion to CDA from FT contract that delivers to Iroquois, East Hereford or EDA should typically be “upstream” and “firm”
    - Depends on location of bottleneck(s)
- Requires “deal” with FT contract holder

Downstream Diversions = High Risk
- Limited or no capacity available on “extreme” days
- Prorata allocation if any capacity is available

IT = High Risk
- Limited or no capacity available on “extreme” days
- Must compete in bidding process for any capacity that is available

3.5. Summary and Questions – Steve Emond

3.5.1. Summary of Capacities

All facilities available
- Capacity available to Enbridge CDA & EDA
- Must compete for capacity, more of an issue in the EDA

Firm (with loss of critical unit)
- Less capacity available to Enbridge CDA & EDA
- Must compete for capacity

Extreme day: impact on non-firm services
- Jan/09 (600 TJ capacity loss): CDA could be restricted
- Sept/09 Line Break (1,770 TJ capacity loss): CDA & EDA could be severely restricted
- Union outage: Impact? 2.5 Bcf?

3.5.2. Summary of Options

Firm services
- FT: lowest risk
- STFT: low risk if contracted before “extreme” day

Supply sources
- Empress: excellent supply availability

- North Bay: need to ensure upstream supply/transport
- Dawn: capacity may be available

Upstream Diversion

- Typically low risk; need FT partner

Downstream Diversion & IT

- Risky

3.5.3. Six Factors to Keep in Mind when assessing risk

1) Upstream grid
   - Need to think about risks and capacity constraints on any upstream pipeline…… Union, GLGT, Vector…
   - EGD is highly reliant on Union system

2) Service Priority
   - Long Term Firm, upstream Diversions and pre-contracted STFT have lowest risk

3) Higher risks associated with large Distributor Delivery Areas “DDAs”
   - localized constraint = broad impacts

4) Lots of capacity on Average day

5) Risks are higher on “extreme” days
   - Impact of extreme cold weather; impact of flow volatility

6) Not just a question of how much capacity; also a question of who gets the capacity that is available; i.e. FT customers versus interruptible customers.

4. Scheduling Discussion

Bob Betts indicated that several committee members, including DE and Board Staff, would not be available for the next scheduled meeting currently planned for March 25. He suggested that the committee consider an alternate.

After some discussion those in attendance agreed that April 8 would be the best day for the next meeting.

Bob also referred to an earlier Enbridge slide 3 showing next dates for meetings specifically referencing “Apr 22 - Settlement negotiations; report to consultative, other?” He asked the committee their views on whether they were ready to report back to the larger consultative yet?

After some discussion the committee agreed that because of the postponement of the next meeting we should set April 22 as tentatively the date that Enbridge would table its position on the system reliability issue and at that time the committee would decide the timing on the remaining steps.

Direct Energy asked if the committee would be prepared to enter into negotiations toward a settlement after Enbridge tabled its position on the matter. All agreed that a form of Settlement conference would begin after that on a schedule agreed to be this committee.

IGUA raised a point about the larger consultation group involvement, and it was agreed that the committee would first try to reach consensus, or alternately agree on a narrowed list of issues, which would be distributed to and then presented to the larger group for further discussion.

With respect to the remainder of this meeting, after committee discussion and a suggestion by IGUA the committee agreed that it would finish the system reliability agenda and postpone the mass market unbundling. Both Direct Energy and Enbridge, who had scheduled presentations on mass market unbundling agreed to that approach.

5. Shell Energy – Option 5 Firm Delivery/Issues for discussion – Paul Dumaresq

Paul indicated that this presentation was in response to the Action Items SR2.03 and SR2.11 arising in the notes from the January 21, 2010 Committee meeting.

SR2.03 “Rather than continuing the discussion on this topic, EGD asked Shell to review the other issues raised on slide 9 and prepare its position on them to be reported to the committee for the next meeting”; and SR2.11 “EGD asked Shell to fill in the boxes for Option 5. Firm Delivery / Financial rating”.

Shell set the stage by indicating that they are here as a “producer” not as a “marketer” per se, representing the producer’s position.

He described Shell’s proposal as follows:
The producer provides Enbridge with the producer’s credit rating and some kind of assurance that deliveries will be showing up at Enbridge’s CDA or EDA, or wherever they need to be.

To facilitate the review Enbridge brought the Shell option up on the screen for committee viewing, that subject portion has been inserted into these notes for ease the review of the reader.

Portion of Options for long term resolution taken from Slide 9, of January 21, 2010 Enbridge presentation – “System Reliability Working Committee”

5	Firm Delivery (Shell Energy)	Issues for Discussion
	1. Direct Purchase Eastern delivery clients of EGD must provide written documentation	• definition and criteria that meets firm delivery. • documentation, validation • consequences of failure to deliver: impacts,

	showing they possess firm deliveries to the Enbridge system from their supplier. 2. Supplier must meet a minimum credit/financial threshold that is agreed to by the Working Committee and the stakeholder group.	penalties •determinant of minimum credit/financial threshold – credit rating? supply obligation in aggregate? marketer specific? •LOC, parental guaranty, others? •monitoring and oversight responsibility – price volatility impact of credit/financial threshold •impact on competition – non-competitive aspects; ease of entry, others? •financial credibility solve the problem of a lack of firm transport? •Additional issues from Working Committee

After touching on the points 1 and 2 under Firm Delivery (Shell Energy) Paul reviewed the list of Issues for Discussion adding comments as he proceeded.

“definition and criteria that meets firm delivery.” – Paul indicated that acceptable criteria would include a requirement for the supplier to provide an investment grade credit rate, triple B minus minimum, established by Moody, S&P, etc.

“documentation, validation” – This would be the letter from the mass marketer stating volumes, delivery point and the supplier; the suppler could provide validation if Enbridge felt it needed to spot check the information provided by the mass marketer.

“consequences of failure to deliver: impacts, penalties” - These would be the same penalties that exist today for the mass market.

“determinant of minimum credit/financial threshold – credit rating? supply obligation in aggregate? marketer specific?” – No comment added.

“LOC, parental guaranty, others?” - Paul felt that the LOC or parental guaranty should not be necessary when an investment grade credit rating is provided, but they could be an alternative to an investment grade credit rating.

“monitoring and oversight responsibility – price volatility impact of credit/financial threshold” - Enbridge would monitor and oversee in the same manner as they do today with the Interim Resolution procedures.

“impact on competition – non-competitive aspects; ease of entry, others?” – Shell indicates there is no impact on competition. In the case of a party that could not provide an investment grade credit rating, they could use alternatives such as a LOC or they could increase their FT nominations to provide the assurance.

“financial credibility solve the problem of a lack of firm transport?
Additional issues from Working Committee” – Paul indicated that the issue of a potential downgrade to credit rating and the resulting increase in cost of capital will prevent any potential failure to deliver.

Shell indicated they would provide a copy of their filled-in table for Option 5 and circulated it to all parties.

Enbridge asked Shell about the “impact on competition”. The first point regarding how many suppliers would be able to compete with Shell and BP if the investment grade requirement was established; Enbridge asked also what if Enbridge wanted more than a BBB^{--} , how many suppliers would be able to provide a higher credit rating, perhaps a minimum of B? IGUA indicated that those that didn’t have an investment grade credit rating would have to provide the alternate assurance like an investment grade parental guaranty or an LOC.

Enbridge indicated a concern about the LOC in a market when the price of natural gas showed some volatility; how would Enbridge and the shippers/suppliers be able to administer the LOC to keep their values at an appropriate level? IGUA suggested that the value of the LOC could be grossed up to reflect pricing pressures in a competitive marketplace in a tight delivery scenario.

Shell was asked how this option would have worked in the January 2009 pipeline constraint scenario. Paul felt that it would have worked because supplies actually did arrive in the EDA and CDA, it was just a question of much parties were prepared to pay to get the gas delivered. The issue of potential credit rating downgrade for failure to deliver would have brought the gas to the area.

IGUA followed on that question by saying that the only way this option can be considered as a reasonable alternative is to agree that there isn’t pipeline capacity issue. Shell agreed, but added that it would serve to provide some additional comfort to Enbridge.

IGUA added that assuming there is no capacity issue a sufficiently aggressive penalty associated with failure to deliver would be as effective and would not have the associated competition impact issues. Furthermore, if there is no pipeline capacity issue is this option even needed. IGUA went further to say that if it is concluded that there is, or could be a pipeline capacity issue, that neither this solution nor the aggressive penalty solution could mitigate the risk. Shell agreed with IGUA’s points.

Enbridge added another problem with this option associated with suppliers not trading publicly and therefore not having a credit rating. In these case, and there are several, their credit worthiness would have to be established in some other way or they would be prevented from competing in the supplier market. A further check by Enbridge confirmed that they have 58 suppliers listed in their records and of that group only 10 or 12 would have sufficient credit rating to satisfy the criteria for this option.

VECC commented on the relative benefits of stronger penalties versus credit ratings saying that at least with the credit rating you may avoid some of a shortfall problem, rather than the penalty approach which is after the fact and only helps clean up the problem.

Another issue associated with higher penalties is that some small supplier that defaults on deliveries, may simple declare bankruptcy rather than pay-out large penalties, leaving the utility with no benefit.

IGUA provided a further assessment of the Shell option by saying that it does not provide any material comfort to Enbridge in regard to failure to deliver, it only offers Enbridge the consolation that Shell's credit rating might go down as a result of its failure to deliver. IGUA expressed uncertainty of the level of real risk that Shell would be downgraded because it failed to deliver in a constrained market condition.

Direct Energy suggested that the only real benefit from this approach is that it might reduce the number of suppliers, maybe from 58 to 10 or 12, which could be contracting for delivery to Enbridge's franchise. Shell argued that the 40 or so that did not have sufficient credit ratings would have to contract firm if they wanted to continue supplying.

Enbridge raised another concern about either credit ratings or LOCs as ways of reducing concerns about failure to deliver. Enbridge referred to a term in their agreement with TCPL that allows TCPL to seek financial remedies from Enbridge if Enbridge over-drafts the system, as could very easily happen in an extreme scenario. Enbridge said that the LOC and the Credit Rating would be of little value unless they were supported by an agreement that Enbridge could pass on or share those TCPL downstream liabilities with shippers in the event of failure to deliver.

The committee agreed that this option would remain on the table for now for further evaluation of relative costs and benefits.

6. EGD Presentation – Keith Irani

Keith started with an update for the committee on the reinstatement of FT Turnback for 2010, slide 6. Enbridge indicated that the FT turnback will be reinstated as it was and shippers will be informed on March 1st. Enbridge said that any change that might be proposed on the methodology related to FT turnback would not be considered until this consultation process concludes.

6.1. Curtailment of Firm Customers Failing to Deliver their MDV

Keith moved on to slide 9 to present Enbridge's finding on the costs of curtailing firm customers, including hardware, construction, maintenance and monitoring. The table in slide 9 laid out component and total estimated cost for curtailment of pipe sizes from 2 inch to 8 inch.

Enbridge indicated that this table applies to Firm Customers who fail to deliver the MDV (Mean Daily Volume) and how Enbridge could cut-off their demand to address that delivery shortfall. Enbridge pointed out one problem with this concept being that the current rate handbook, does not allow Enbridge to cut-off a firm customer under these circumstances because they are still entitled to some gas, determined to be the difference between the contract demand and the MDV. Thus the rate handbook would have to change.

Questions to Keith combined with his answers clarified certain points on the table, which were:

- The first 6 columns are the costs for an individual customer with that particular size of pipe;

- The last 4 columns represent the total costs if there were 50 customers all with that size of pipe,
- The SCADA costs in the second last column are the costs for 50 customers;
- The total in the last column are for a group of 50 customers with a particular pipe size;
- A group of 50 large use customers would have a variety of pipe sizes.

The conclusion to be drawn here is that the total cost for installing remote curtailment equipment at 50 large use firm customers would range from a low of $1.905 million if all were 2 inch, up to a high of $2.44 million if all were 8 inch, but would probably end up somewhere in between those extremes. (Note that $240,000 of the total is an annually occurring SCADA operational cost.)

Enbridge reminded everyone that this is for a “shut-off” valve, not a valve to reduce flow. Flow reducers are substantially more expensive. A shut-off scenario creates problems associated with current agreements that allow customers some gas even when they fail to deliver, therefore the terms of current agreements would have to change to allow Enbridge to actual shut-off the flow entirely.

AEGENT asked about the possibility of installing flow control valves instead of shut-off valves. Enbridge thought that would add about $250,000 to the valve price alone for each customer.

IGUA asked for assistance in assessing the relative costs of this curtailment option against the costs of asking a large user to firm up their entire supply of natural gas. With input from other committee members it was estimated that the difference between firm transport and discretionary (Interruptible) would be as much as $500,000 per year, ***NOTE: This was later clarified to be closer to $130,000, approximately one-third of $500,000, on the premise that Enbridge would only require FT for 4 of the 12 months of the year (December to March inclusive).***

IGUA noted that for a large user the $500,000 annual transport cost savings would probably justify the initial installation cost and the annual maintenance and operational costs of the remote shut-off equipment. Even the estimated cost of a flow control valve might still make sense. This of course would be very much dependent upon the individual customer’s operational profile and the operational costs and risks their business would face if their natural gas supply was cut-off.

VECC made the point that if the large user had a tolerance to be shut-off they would probably be contracted with Enbridge as interruptible already.

As was pointed out earlier, there would still need to be some changes to customer agreements to allow Enbridge to completely shut-down the supply to a customer if their deliveries failed to arrive, since the existing agreements allow them to continue taking some natural gas even if the deliveries are not made

IGUA agreed that there was enough information here about curtailment costs for him to survey IGUA members who are large users, to get a sense of their interest in the curtailment option, both remote shut-offs and remote flow-controls.

Enbridge agreed to confirm the estimated additional costs of flow-control equipment versus shut-off equipment, and Enbridge also agree to survey other large users that may not be part of IGUA's membership.

Both IGUA and Enbridge agreed to report back at the next meeting.

Keith moved on to slide 10 which summarized the penalties and fees included in TCPL's Tariffs. Enbridge indicated that it would be necessary to have agreements reflecting Enbridge's right to recover such costs from direct shippers if they fail to deliver promise gas.

Slide 11 first showed Enbridge's analysis of the volume of gas not underpinned by firm contracts which totaled up to 288,866 GJs. This analysis used the actual observations from January 2009 for how much interruptible was able to be firmed up. The 288,866 was the amount that Enbridge estimated is at risk of not being firmed up and therefore failing to be delivered.

The next slide, 11, summarized the impact if such a shortfall materialized and the options Enbridge would have to manage such a shortfall. EGD indicated that their only option for handling this shortfall, in a scenario when no additional capacity was available on TCPL, was to shed load, and the only two ways to effectively and reasonably shed that much load would be to:

- First curtail the top 50 firm large users which would account for about 70,000 GJs; and
- Second, to cut off entire communities, possibly even municipalities, where they could isolate gate stations, such communities could include: Oshawa, Pickering, Barrie and others.

Enbridge clarified that Toronto is not easily isolated due to the network of pipes and the multiple feed in points.

Direct Energy asked if Enbridge had done some contingency planning for such an event. Enbridge indicated that they have looked at times at this kind of an emergency scenario, but had not formalized any kind of a plan, since the objective is to never have anyone shut-off because of failures to deliver.

VECC commented on the seriousness of such a massive system shut-down and how it could take a month to get natural gas flowing back into homes.

6.2. <u>***New-*** Option 6 - Peak Day Design Methodology – Degree Days</u>

Direct Energy raised an issue about Enbridge's current peak day planning and Enbridge's current Design Day of 39.5 degree days, when the franchise has already experienced an actual 43.8 degree day. DE asked why Enbridge has not adjusted its Design Day to reflect historic temperatures, thereby reducing the risk of having insufficient supply to meet extreme temperatures.

Enbridge agreed that this is a very good question, particularly in light of Union South using a 44 degree day in their Design Day, in an area generally marked with warmer winters. Enbridge indicated the next slide would be putting that forward as another option to consider.

Slide 13 summarized the Design Degree Day values used by Union and GMi (Gaz Met) which is 44 heating degree days or more, in comparison to Enbridge with at 39.5 heating degree days, providing 4.5 degree days less supply contingency. Enbridge also noted that GMi had in its methodology a reserve margin to meet its historical peak day of 46 heating degree days.

Enbridge also noted that they design for average wind conditions, but have observed that wind speeds of 25 mph can add 300,000 GJ demand independent of the temperature. They noted that GMi received approval to recognize wind speed impact in their new Peak Day Design methodology.

The slide also showed two notable historic degree day values of 43.8 DD, January 15, 1994 (a Saturday) and more recently, 39.5 DD, Friday, January 9, 2004.

In response to a question from IGUA about how this change would assist with this issue, Enbridge indicated that the higher Design Day DD would allow them to contract additional firm volumes which would provide Enbridge with additional confidence in their ability to manage extreme supply conditions.

Enbridge indicated that another way to increase certainty of system supply reliability would be to add a reserve margin to the design methodology as GMi has.

6.3. ***New-*** Option 7 - Replace Peaking Contracts with STFT

Enbridge has some concerns about the reliability of their current Peaking Supply contracts. They have observed that largely the same suppliers provide peaking supply, direct purchase supply and CDS, and the supplier's ability to use that situation to reflect a supply shortfall in any of the categories, based on relative penalties. In other words if capacity is not available and the supplier must short ship on some contract, they could chose to fill commitments to direct shippers if the penalties or risks were higher than penalties in the peaking agreements.

To resolve that system supply reliability concern, Enbridge could replace the peaking supply with STFT.

IGUA inquired about the costs of such a change to STFT instead of peaking and Enbridge indicated that their early estimates indicated this would cost the system supply customer approximately $3.00 per year and the direct purchase residential customer about $6.00 per year. Enbridge will refine the costs and benefits of this option and report them in the March meeting.

IGUA indicated that based upon Enbridge's observations and associated system supply reliability concerns that Enbridge should really be making this change anyway. Enbridge agreed.

Enbridge added that since the concerns were first recognized they have reviewed contracts and penalties in an effort to tighten the supply confidence, but the concerns still exist.

IGUA asked Enbridge if they could provide a table that would show how much these incremental supply improvements, like DD change and STFT replacing Peaking could alleviate of the total system reliability issue and how much they would cost. Enbridge agreed to do that.

Shell asked if this and/or the DD change options were found acceptable would that resolve the system reliability issue that was the genesis of this consultation. Enbridge indicated that they would like to evaluate that answer for the March meeting. At this point they can't be sure whether the problem could be resolved by one of the options or perhaps several options being utilized together.

6.4. Discussion about the Merits of the NEW Option 6 & 7 as Resolutions to the System Reliability Issue

Aegent commented that STFT for peaking needs and a higher DD for design day may be necessary because the reliability problem would not be resolved with direct shippers taking firm transport. That was because the direct shipper could provide their MDV, which is their contractual obligation, but that would do nothing to mitigate a problem with weather coming in 5 degrees colder than the design day. Direct Energy agreed and referred to the January 2009 scenario when all deliveries were met, he said had it been 5 degrees colder there would be no requirement for direct shippers to deliver any additional volume.

IGUA responded by saying that Enbridge's point is that had the cold conditions lasted longer or had the temperatures been even colder, then the direct shippers would not have been able to continue delivering their MDV because it was not backed up with firm delivery, and STFT contracts were being refused by TCPL. At that point there would have been direct shippers not delivering, and Enbridge's peaking and CDS would not have been able to compensate.

Direct Energy agreed that at that point Enbridge would not be able to get any additional peaking or CDS, and everyone would share in the problem, unless a higher design day heating degree day and underpinning their peaking with full season STFT was adopted.

IGUA agreed that the higher degree day and additional full-season STFT underpinning of peaking requirements would assist in solving the problem, but they would also exacerbate the issue of direct shippers not being able to deliver the MDV because even more capacity would be committed to firm transport, leaving less for Direct Shippers to compete for to deliver their MDVs. That again leads to the issue of shortfall in deliveries and potential system reliability problems.

VECC then pointed out that these would all mean higher costs and that direct shipper customers should pay those costs. Direct Energy said that no matter how this problem gets resolved it will cost more money, the committee needs to find the best way to do it, at the lowest cost possible, and then determine who will pay the costs.

Direct Energy summed up their position with respect to the Design Day heating degree day value by saying that unless Enbridge increases the DD, even if direct shippers deliver all of their MDV, there would still be a shortfall because there would be inadequate contingency quantities of peaking and CDS.

IGUA and VECC commented that the only logical answer is to underpin all three of these components: direct shippers MDV firm contracting, additional STFT replacing peaking and CDS with 100% FT. IGUA qualified that by saying that they are not ready to recommend that approach at this stage, but it does seem to be the only logical answer right now.

Enbridge indicated that they would assess each of the three options to determine: 1) their costs and 2) how much of the at-risk volume each option could offset. Enbridge will provide that for the next meeting and the group could see if a combination of the three could serve to satisfactorily resolve the risk. IGUA added within some livable tolerance, which Enbridge agrees with.

Referring to slide 16, VECC asked about the “storage withdrawal” volume of 2,133,000 GJ and whether that could be increased to mitigate this system reliability problem. Enbridge agreed that it could, but that it would have to be done in conjunction with additional storage related transport to get the gas to the CDA and EDA, which is currently at capacity. That would probably mean additional build and would therefore be a longer term solution.

Keith moved on to slides 15 and 16 and indicated that slide 16 represents Enbridge’s Peak Day supply portfolio with the two new options applied.

IGUA asked if Enbridge is confident that the Curtailment volume of 177,800 GJs could be considered firm, and Enbridge indicated that if their assessment ended up with some doubt about getting that full volume from curtailment due to non-compliance, that it would probably force one or more of the other volumes up to compensate.

Enbridge agreed that the curtailment protocols require some firming up and additional work on the interruptible side

Keith quickly moved over slides 17, 18 and 19. Slide 17 summarizing the last two options discussed here today.

Slides 18 and 19 are the System Reliability Matrix with VECCs comments added. Keith pointed out that slides 18 and 19 needed to be updated to include comments received from Direct Energy and the addition on Options 6 and 7, EGD Design Day DD and Replacing Peaking with seasonal STFT.

7. <u>Closing remarks</u>

In closing the meeting, Bob Betts asked if there were any other matters anyone wanted to bring up. IGUA asked that all presentations be distributed with as much lead time as possible. Enbridge understood the concern and said they would do the very best.

The group then discussed the pros and cons of trying to cover both system reliability and mass marketing unbundling in the same timeframe and on the same day. IGUA wondered whether the committee should focus on system reliability now that the committee seems to be getting to the heart of the issue and the essence of a possible solution mix. All looked to Direct Energy for their view.

Direct Energy indicated that they were willing to see the emphasis on the system reliability issue, but they would not like to see the mass market unbundling be delayed to a point that changes could not be implemented in a reasonable time.

Parties felt that there is probably good reason to have a full day devoted to system reliability for the next meeting and that maybe an additional meeting could be held to catch-up on mass market unbundling.

The group agreed to a suggestion by Direct Energy that we have a half day catch-up meeting on Mass Market Unbundling on Friday, March 12, 2010.

For clarification, Shell asked if today's session concluded that there was sufficient capacity supplying the CDA and EDA.

TCPL responded by saying that there is sufficient capacity to fill firm contracts; the issue is how parties contract for it. There isn't any identified need to build new pipe, because the pipe is capable of supplying the current firm contracts.

IGUA commented that the response depends on how you define capacity. IGUA suggested that there is not sufficient capacity available for all parties if they all decide to nominate for it at the same time, under any and all conditions.

Adjourn

With that, the meeting was adjourned at 4:55 PM.

<u>Note to Readers:</u>

Action items arising from this meeting can be found in Appendix D.

Appendices

Appendix A: Meeting Agenda February 25, 2010

COMMITTEE MEETING

Thursday, February 25, 2010
9:00 AM – 12:30 PM
500 Consumers Road, Learning & Leadership Board Room
(Please enter via Link Security/Employee Entrance)

System Reliability

AGENDA

9:00 - 9:10 am	**Opening Remarks -** Bob Betts, Facilitator ▪ Welcome and Housekeeping Items ▪ Objectives and plan for this meeting ▪ Next steps
9:10 – 9:30 am	**Review and Discussion of the Consultation Process Plan Going Forward and the Nature of the Application to Follow** - Malini Giridhar/Norm Ryckman
9:30 – 11:30 am	**TransCanada Pipelines Presentation**
11:30 – 11:45 am	**Break**
11:45 am – 12:00 am	**Shell Energy Report – Option 5 Firm Delivery - Issues for discussion**
12:00 am - 12:30 pm	**EGD System Reliability Presentation -** M. Giridhar/K. Irani ▪ Option 4: Curtailment of firm customers - hardware, construction and monitoring costs ▪ System reliability matrix – survey summary
	LUNCH

Appendix B: Participant Listing

Stakeholders

Attendee	Organization
Frank Brennan	AEGENT
Vince DeRose	CME
Ric Forster	Direct Energy
Jamie Humble	Direct Energy
Brad Janzen	Direct Energy
Ian Mondrow	IGUA
Colin Schuch	Ontario Energy Board
Lawrie Gluck	Ontario Energy Board
Paul Dumaresq	Shell Energy
Murray Ross	TCPL
Lisa DeAbreu	TCPL
Steve Emond	TCPL
Zafir Samoylove	TCPL
Ken Schubert	TCPL
Jim Bartlett	TCPL
Chris Ripley	Union Gas
Don Newbury	Union Gas
Julie Girvan	VECC & CCC
Roger Higgin	VECC & CCC

Enbridge Representatives

Attendee	Position
Malini Giridhar	Director, Energy Supply & Policy
Keith Irani	Manager, Energy Supply Services
Hilmi Muhammad	Manager, Energy Forecasting and Planning
Robert Bourke	Manager, Regulatory Proceedings
Ian Macpherson	Manager, Direct Purchase
Kent Wirth	Manager, Gas Control & Nominations
Moin Kazi	Senior Energy Analyst

Other

Bob Betts	Facilitator, Regulatory Support Services

Appendix C: EGD System Reliability Presentation by Keith Irani / M. Giridhar

ENBRIDGE

System Reliability Working Committee

February 25, 2010

System Reliability Working Committee Opening Remarks – Bob Betts, Facilitator

- Welcome & Housekeeping Items
- Objectives and Plan for the Meeting
  - Review from previous meetings
  - Presentation and discussion of Shell Energy option and EGD new options, and associated issues to:
    - Gather additional committee input and finalize
- Stakeholder meeting

System Reliability - Plan Going Forward

- Feb 25
  - TCPL Presentation
  - Further discovery and consideration of options
- Mar 25
  - Final Discovery Phase
  - Initial discussion of all party positions – Enbridge and all parties
- Apr 13
  - Enbridge presents its preferred position
  - Consultative discussion about how to proceed, either:
    - Begin settlement phase, Report back to larger committee, or Both
- Apr 22
  - Settlement negotiations; report to consultative, other?
- May 20
  - Continued negotiations, if required.
- June 30 (or as soon as practical)
  - Enbridge files application with the Board (separate or within some other application?)

System Reliability – Nature of the Application

The timing and form of the application will finally depend on the outcome of this consultation; however, Enbridge confirms that an application will be made in a timely and efficient manner, with an implementation target no later than 2013.

Things Certain:

- The application will include:
  - The meeting notes
  - Enbridge’s assessment of need
  - Enbridge’s review and assessment of alternative resolutions, including impacts
  - Enbridge’s requested resolution

Things Uncertain:

- Whether the application will:
  - Include a partial or complete settlement;
  - Be based upon a “narrowed” list of issues and resolutions, resulting from this consultation

EGD System Reliability Presentation

K. Irani/M. Giridhar

FT Turnback for 2010

EGD has reinstated FT turnback pursuant to OEB decision. Turnback quantities are in line with 2008

Service	**2010**	**2008**
Ontario T-Service CDA	100%	100%
Ontario T-Service EDA	88%	88%
Western T-Service	10,000 Gj/d	8,000 Gj/d
Timeline		
Letter to customers/vendors/agents	March 1, 2010	
Notify EGD of turnback	March 31, 2010	
Notify TCPL of contract renewal	April 30, 2010	

Options with timelines

Option	Date discussed	Costing ($)
1. Vertical Slice	Nov 20, 2009	March
2. Interim solution	Nov 20, 2009	March
a. Board interim resolution		
b. EGD interim solution (modified)		
c. Direct Energy		
3. Backstopping service	Nov 20, 2009	March
4. Curtailment of firm customers	Nov 20, 2009	March
5. Firm Delivery (Shell Energy)	Jan 21, 2010	N/A

Update on Firm Delivery - Shell Energy

5	Firm Delivery (Shell Energy)	Issues for discussion
	▪ Direct Purchase Eastern delivery clients of EGD must provide written documentation showing they possess firm deliveries to the Enbridge system from their supplier. ▪ Supplier must meet a minimum credit/financial threshold that is agreed to by the Working Committee and the stakeholder group.	• definition and criteria that meets firm delivery. • documentation, validation • consequences of failure to deliver: impacts, penalties • replacement gas implications? • determinant of minimum credit/financial threshold – credit rating? supply obligation in aggregate? marketer specific? • LOC, parental guaranty, others? • monitoring and oversight responsibility – price volatility impact of credit/financial threshold • impact on competition – non-competitive aspects; ease of entry, others? • financial credibility solve the problem of a lack of firm transport? • <u>Additional issues from Working Committee</u>

Estimated Costs of Curtailment of Firm Customers: Hardware, Construction, Maintenance & Monitoring

Nominal Pipe Size (NPS)	Actuator ($)	Construction ($)	Telemetry ($)	Communicator Controls ($)	Total hardware & Installation ($)	Customers (#)	Total Costs ($)	SCADA ($)	Total ($)
NPS 2	7,300	5,000	20,000	1,000	33,300	50	1,665,000	240,000	1,905,000
NPS 3	8,000	5,000	20,000	1,000	34,000	50	1,700,000	240,000	1,940,000
NPS 4	8,600	5,000	20,000	1,000	34,600	50	1,730,000	240,000	1,970,000
NPS 6	18,000	5,000	20,000	1,000	44,000	50	2,200,000	240,000	2,440,000
NPS 8	18,000	5,000	20,000	1,000	44,000	50	2,200,000	240,000	2,440,000

Notes:
Costs vary by regions.
SCADA IT, maintenance and monitoring are $240,000 yearly ongoing cost.

TransCanada Pipelines Limited Transportation Tariff Section XXII (p. 34-41)

- TransCanada determines a daily variance (if any) for a shipper at a delivery point/area based on the difference between the quantity authorized by TransCanada and the quantity delivered to the shipper.

- Shippers who have a daily variance incur a daily balancing fee predetermined and described in TransCanada's tariff.

- EGD holds the daily variance on behalf of all shippers delivering into EGD's delivery areas.

- If the shippers daily variance impacts TransCanada's ability to meet firm obligations even after curtailment of all discretionary transportation services, TransCanada may, without further notice, adjust shippers nominations in order to reduce the variance to zero.

- Remedies available to TransCanada under the above circumstance may exceed imbalance penalties levied on shipper.

TCPL Deliveries to EGD – 2009 Peak Day Design

TCPL Deliveries to EGD: 2009 Peak Day Design

Degree Days	**2009 Peak Day Design 39.5** **GJ**
Table 1 - TCPL Deliveries	
TCPL FT	
EGD Long Haul - FT	291,130
EGD Short Haul FT	349,390
STS	364,503
DP Firm LH FT	36,362
Total FT Deliveries	**1,041,385**
TCPL Non FT	
Peaking	269,000
CDS[1]	140,000
Non FT Direct Shippers	419,648
Total non FT deliveries	**828,648**
less: STFT	(539,782)
Total non firm deliveries	**288,866**

Notes:

Assumes a certain proportion of interruptible customers will use CDS.

Assumes that level of design day STFT will continue to be contracted.

Impact of Delivery Shortfall on EGD Operations

- Impact of a shortfall of 288,000 Gj's off TCPL
  - EGD and/or the customer has to increase nominations
    - This may not be possible as all FT contracts are maxed
    - IT on TCPL is not available

- Options available to EGD operations
  - Curtail top 50 firm customers (70,000 Gj's)
  - Isolate gate stations that would readily provide the remaining shortfall, for example the communities of Oshawa, Pickering, Barrie and others.

New option - Revise EGD's current Design Degree Day to align with Union and GMi

Union Gas South	Union Gas North	GMi*	EGD	Implications for EGD
• plans and contracts for 44 heating degree days	• plans and contracts for a varied level of heating degree days	• GMi plans and contracts for 44 heating degree days with a reserve margin to meet historical peak of 46 DD	• EGD plans and contracts for 39.5 heating degree days	• EGD has less contracted capacity than GMi and Union Gas to meet contingency supply

Background

• Highest degree days in EGD's franchise in last 20 years:

1994: 43.8 DD, Saturday, January 15.

2004: 39.1 DD Friday, January 9.

• EGD's design day method assumes average wind. However, high wind conditions can significantly affect demand. For example, the difference between 10 mph and 25 mph wind speed can add 300,000 GJ demand on peak day.

• *GMi will adopt a new peak day methodology in 2010 to recognize impact of wind.

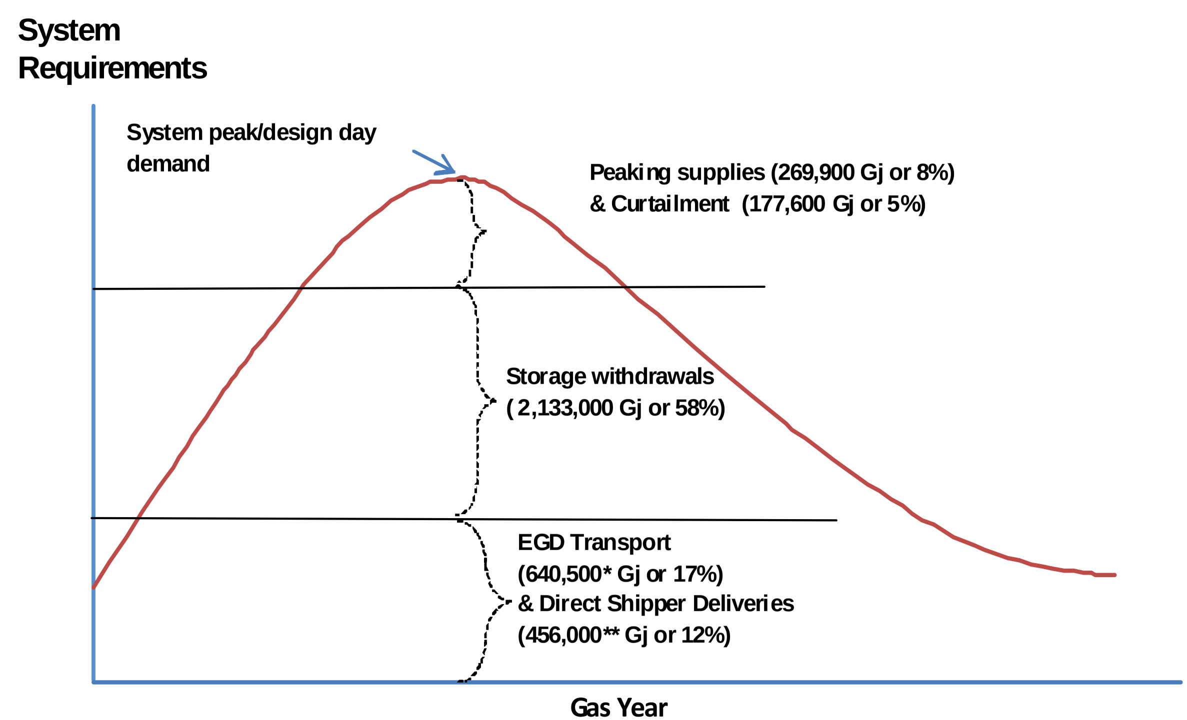
New Option - Replace Peaking Contracts with STFT

EGD’s observation is that largely the same group of suppliers provide peaking supply, direct purchase supply and CDS.

- Suppliers may chose to reflect a supply shortfall in any of the categories, based on relative penalties

- Replacing peaking supply with STFT improves reliability of the portfolio.

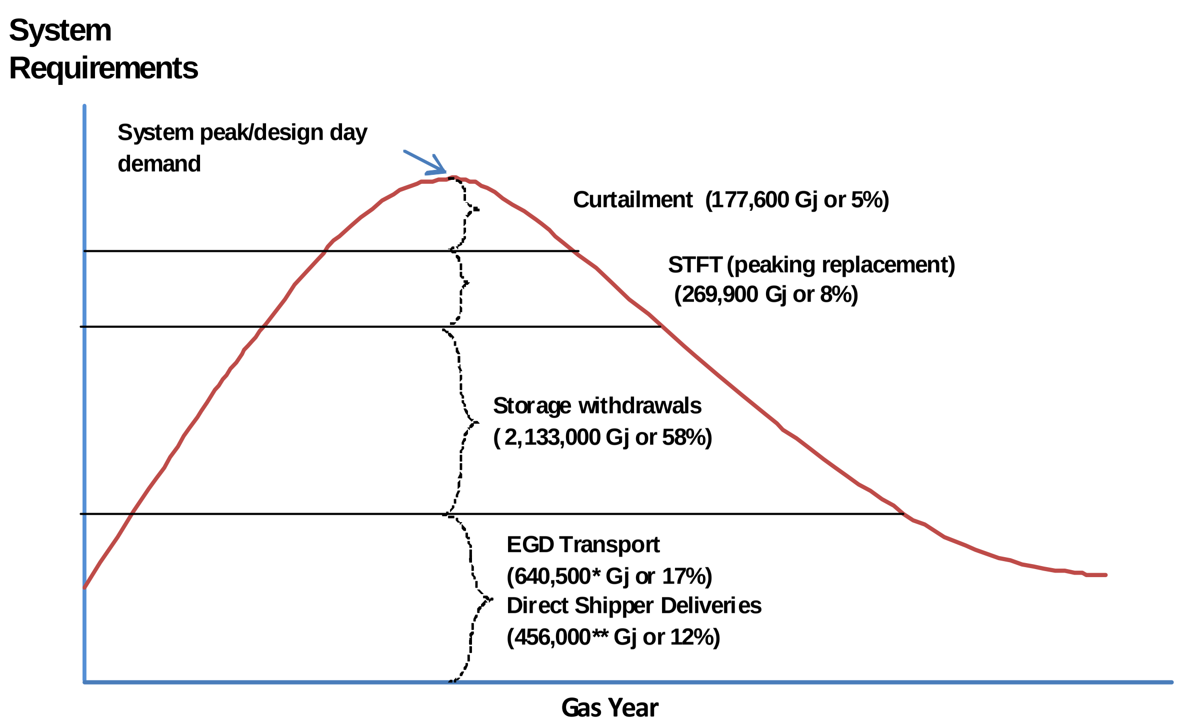
EGD Design Peak Day Portfolio



* EGD assignment to Ontario T: 61,000 Gj/d;

** Ontario T-Service FT: 36,362 Gj/d

EGD Design Peak Day Portfolio with STFT and no Peaking



* EGD assignment to Ontario T: 61,000 Gj/d;
** Ontario T-Service FT: 36,362 Gj/d

EGD New options for Long Term Resolution

6	**EGD Design Day (EGD)**	**Issues for discussion**
	▪ Review EGD's current design degree day ▪ Update design day criteria	• Is EGD's current design day methodology appropriate? • Harmonization of degree day with Union South • Potential impact of change on EGD's gas supply portfolio • <u>Additional issues from Working Committee</u>
7	**EGD Peaking Contracts** ▪ EGD replaces peaking contracts with STFT ▪ STFT contracts for 3 winter months ▪ Increases robustness of EGD portfolio	• treatment of the potential incremental costs of replacing peaking with STFT •<u>Additional issues from Working Committee</u>

System Reliability Matrix

Impact of Options	System Reliability			Competitiveness	Ratepayer/ Stakeholder impacts	Term
Options	Firm Transport	Incremental Supply (backstopping)	Load Reduction (curtailment of firm customers)	Impact on Competitive Market	Ratepayer & Stakeholder Impacts	Estimated Lead time
1. Vertical slice	• firm contracts to delivery area	• not required	•not required		TBD (CCC/VECC)	2-3 yrs
2. Interim						
a. Board interim resolution	• firm transport to delivery area (Jan-Mar), increasing 10% each yr	• potential option	• potential option		Cost $xxx (CCC/VECC)	3-6 mths
b. EGD interim solution (modified)	• firm transport (% of MDV) to delivery area (Dec-Mar)	• potential option	• potential option		Cost to be Determined (CCC/VECC)	3-6 mths
c. Direct Energy	• firm transport to delivery area, frozen at 2010 levels	• potential option	• potential option		Cost to be Determined (CCC/VECC)	3-6 mths

System Reliability Matrix

Impact of Options	System Reliability			Competitiveness	Ratepayer/ Stakeholder impacts	Term
Options	Firm Transport	Incremental Supply (backstopping)	Load Reduction (curtailment of firm customers)	Impact on Competitive Market	Ratepayer & Stakeholder Impacts	Estimated Lead time
3. Backstopping service	• potential option	• required	• potential option		Cost? (CCC/VECC)	1 year
4. Curtailment of firm customers	▪ not required	• not required	▪ required		Not Viable Option (CCC/VECC)	1-2 years
5. Firm Delivery/Financial rating	?	?	• potential option		More Info (CCC/VECC)	3-6 mths

Appendix D: Summary of Action Items

From the System Reliability Committee Meeting 3
Held on February 25, 2010

Item	Page	Task	Responsibility
SR3.01	9	Direct Energy asked Enbridge if they could determine what percentage of volume to the CDA was firm. He defined firm in this context as Ontario T Service where direct shippers would not have turned back their capacity. Enbridge said they could do that.	Enbridge,
SR3.02	14	In presenting this slide, TCPL noticed that there was a graphical error in that the bottom two lines- “TransCanada’s Authorized Transport on Union (M12)” and “TransCanada’s Firm Entitlement on Union (M12)” were both shifted one day to the right. TCPL said they would correct the slide and redistribute it later.	TCPL
SR3.03	17	Enbridge indicated that in the next session they would like to expand the review to include a closer look at the firmness of Peaking Service and CDS, and the role they play in the system reliability question. Shell agrees that the committee needs to take a closer look at Peaking Service and CDS.	Enbridge
SR3.04	20	After some discussion the committee agreed that because of the postponement of the next meeting we should set April 22 as tentatively the date that Enbridge would table its position on the system reliability issue and at that time the committee would decide the timing on the remaining steps.	Enbridge
SR3.05	22	Shell indicated they would provide a copy of their filled-in table for Option 5 and circulated it to all parties.	Shell
SR3.06	25	IGUA agreed that there was enough information here about curtailment costs for him to survey IGUA members who are large users, to get a sense of their interest in the curtailment option, both remote shut-offs and remote flow-controls. Enbridge agreed to confirm the estimated additional costs of flow-control equipment versus shut-off equipment, and Enbridge also agree to survey other large users that may not be part of IGUA’s membership. Both IGUA and Enbridge agreed to report back at the next meeting.	Enbridge and IGUA
SR3.07	27	IGUA inquired about the costs of such a change to STFT instead of peaking and Enbridge indicated that their early estimates indicated this would cost the system supply customer approximately $3.00 per year and the direct purchase residential customer about $6.00 per year. Enbridge will refine the costs and benefits of this option and report them in the March meeting.	Enbridge
SR3.08	27	IGUA asked Enbridge if they could provide a table that would	Enbridge

		show how much these incremental supply improvements, like DD change and STFT replacing Peaking could alleviate of the total system reliability issue and how much they would cost. Enbridge agreed to do that	
SR3.09	27	Shell asked if this and/or the DD change options were found acceptable would that resolve the system reliability issue that was the genesis of this consultation. Enbridge indicated that they would like to evaluate that answer for the March meeting. At this point they can't be sure whether the problem could be resolved by one of the options or perhaps several options being utilized together.	Enbridge
SR3.10	28	Enbridge indicated that they would assess each of the three options to determine: 1) their costs and 2) how much of the at-risk volume each option could offset. Enbridge will provide that for the next meeting and the group could see if a combination of the three could serve to satisfactorily resolve the risk. IGUA added within some livable tolerance, which Enbridge agrees with	Enbridge
SR3.11	29	Slides 18 and 19 are the System Reliability Matrix with VECCs comments added. Keith pointed out that slides 18 and 19 needed to be updated to include comments received from Direct Energy and the addition on Options 6 and 7, EGD Design Day DD and Replacing Peaking with seasonal STFT.	Enbridge
SR3.12	29	IGUA asked that all presentations be distributed with as much lead time as possible. Enbridge understood the concern and said they would do the very best.	Enbridge

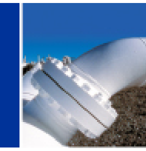
Appendix E: Enbridge Working Committee on System Reliability Presented by TransCanada's Steve Emond, Zafir Samoylove & Ken Schubert

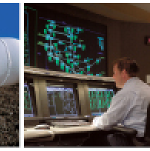
Enbridge Working Committee on System Reliability

February 25, 2010

TransCanada
In business to deliver

Agenda

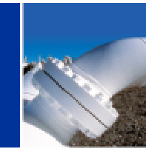


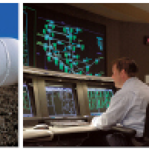


- Risk Factors
- Capacities on TransCanada
- Cold Snap – January 2009
- Capacity & Services Options to Serve Enbridge Markets
- Summary

TransCanada

Risk Factors – Things to keep in mind when assessing risk

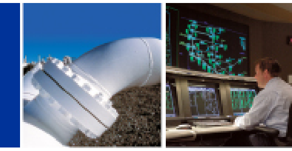




1) **Upstream grid**
   - Not just TransCanada; Need to think about risks and capacity constraints on any upstream pipeline…… Union, GLGT, Vector…
   - Are the risks evenly spread across upstream pipes?
2) **Service Priority**
   - Interruptible, Diversions, Short Term Firm, Long Term Firm…
3) **Higher risks of broad Distributor Delivery Areas "DDAs"**
   - localized constraint = broad impacts
4) **Capacity on Average day**
5) **Risks are higher on "extreme" days**
   - Impact of extreme cold weather; impact of flow volatility
6) **Not just a question of how much capacity; also a question of who gets the capacity that is available.**

TransCanada

Firm Contracts & Peak Deliveries using TransCanada to Enbridge Franchise Areas?



Contracts *	Enbridge CDA (GJ/day)	Enbridge EDA (GJ/day)
TransCanada	633,855	406,099

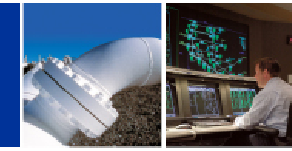
Pipeline	Path	Quantity
Union Gas	Dawn to Parkway	2,157,173 GJ/d **
	• TCPL connection	•~382,000 GJ/d
	• Enbridge connection	•~1,775,000 GJ/d ***
	Dawn to Kirkwall	67,929 GJ/d

TransCanada also holds 1825 TJ/d of capacity on Union

Notes:
* Long term firm contracts effective February 1, 2010
** Includes the FT-SN contract for 85,000 GJ/d to Victoria Square #2 CDA held by Enbridge, but excludes the 3 FT-SN contracts held by power generators to Goreway CDA, Thorold CDA & Victoria Square #2 CDA.

TransCanada

Enbridge is highly dependant on Union



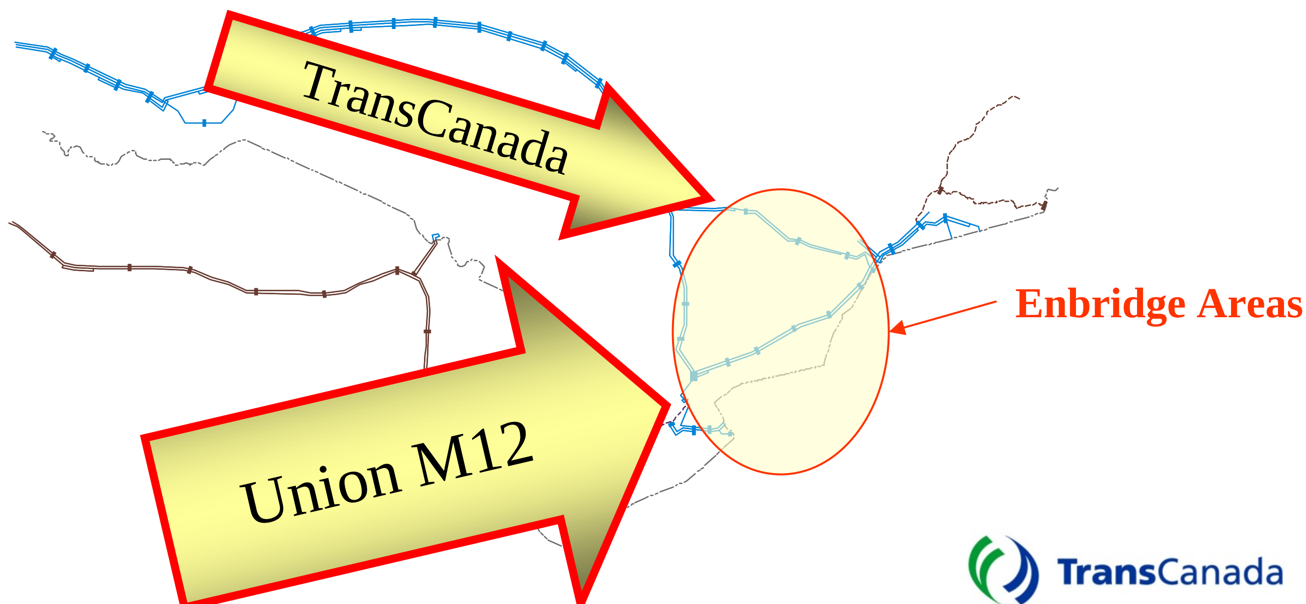
- Potential for significant restriction if Union outage / linebreak

Enbridge Firm Contracts:

TransCanada: 1,040 TJ/d (32%)

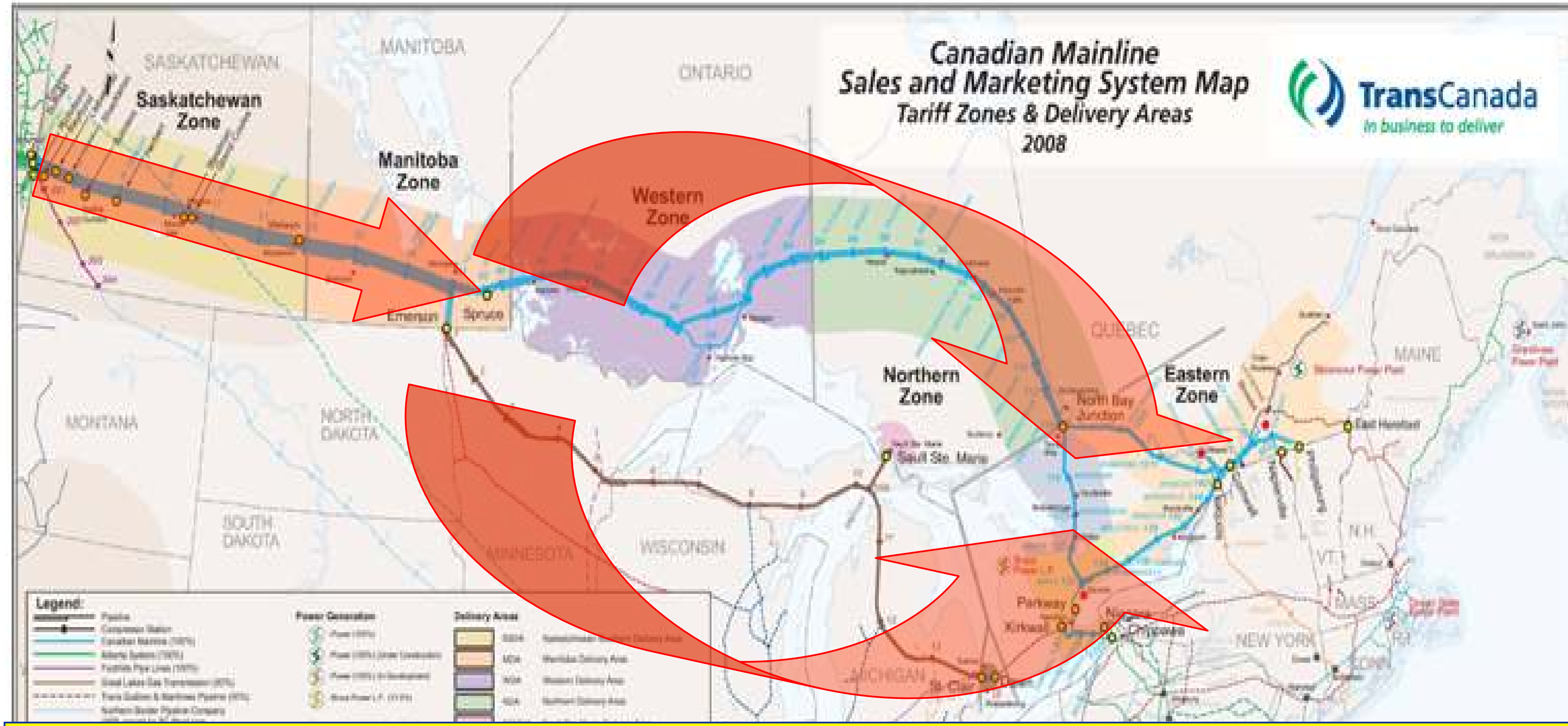
Union: 2,225 TJ/d (68%)

TCPL TBO on Union: 1,825 TJ/d



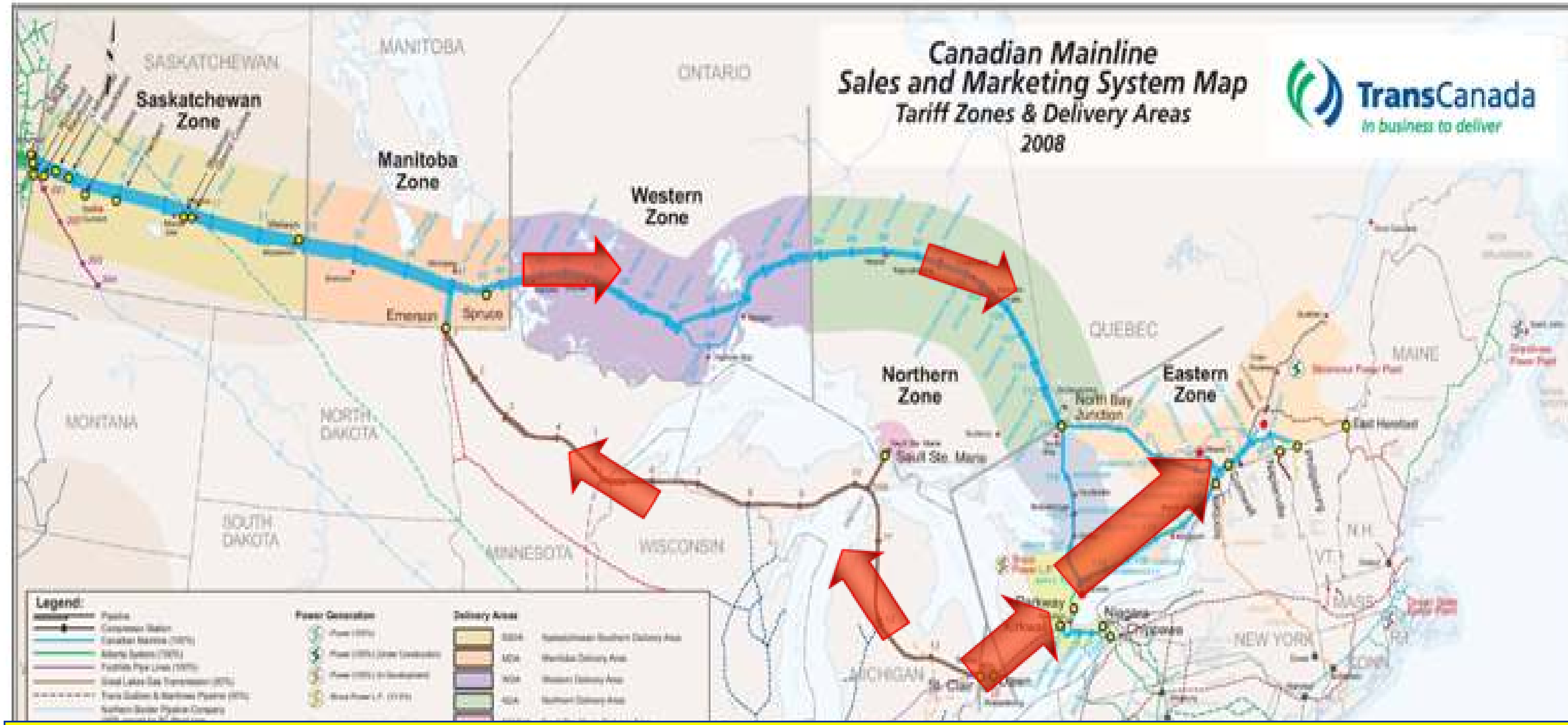
TransCanada

"Long-Haul" TransCanada Deliveries to Enbridge



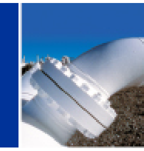
TransCanada can meet Enbridge Firm Contracts via 2 paths

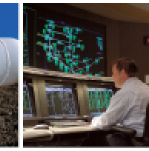
"Short Haul" TransCanada Deliveries to Enbridge



Firm Shipper Contracts on TransCanada are less susceptible to Union outage: TransCanada can shift volumes to the North

Service Priorities



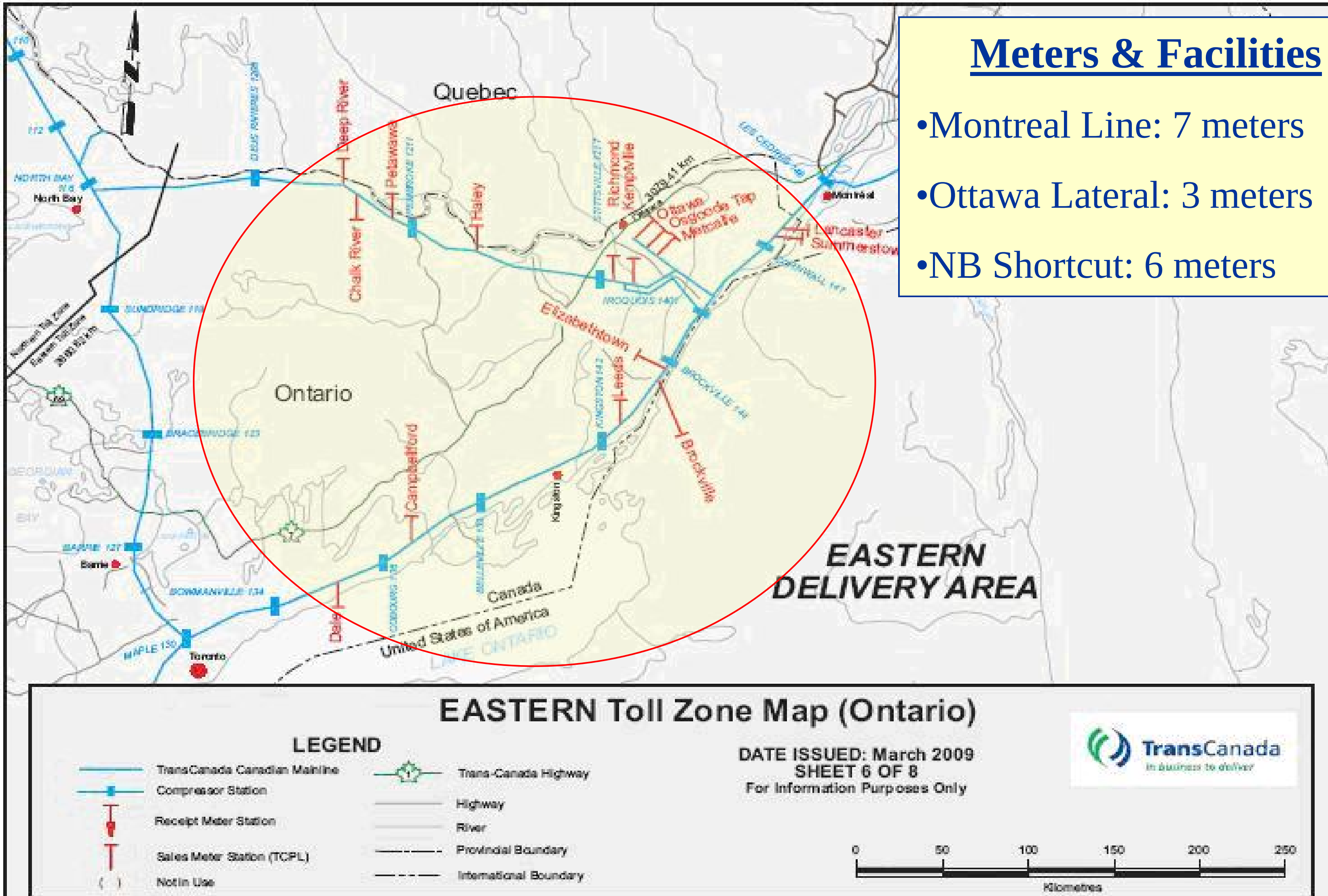


Highest Priority ↓ Lowest Priority		
Highest Priority	1) Firm: FT, STS, STFT, Upstream Diversions	• Capacity allocated on prorata basis
	2) Downstream Diversions	• Capacity allocated on prorata basis
Lowest Priority	3) Interruptible	• Capacity allocated based on bid price

Note:
•This is a simplification of the service priorities. Please refer to Section XV of the General Terms & Conditions of TransCanada's Tariff for a complete description.

TransCanada

Enbridge's Markets Served by TransCanada:
- Enbridge EDA



Meters & Facilities

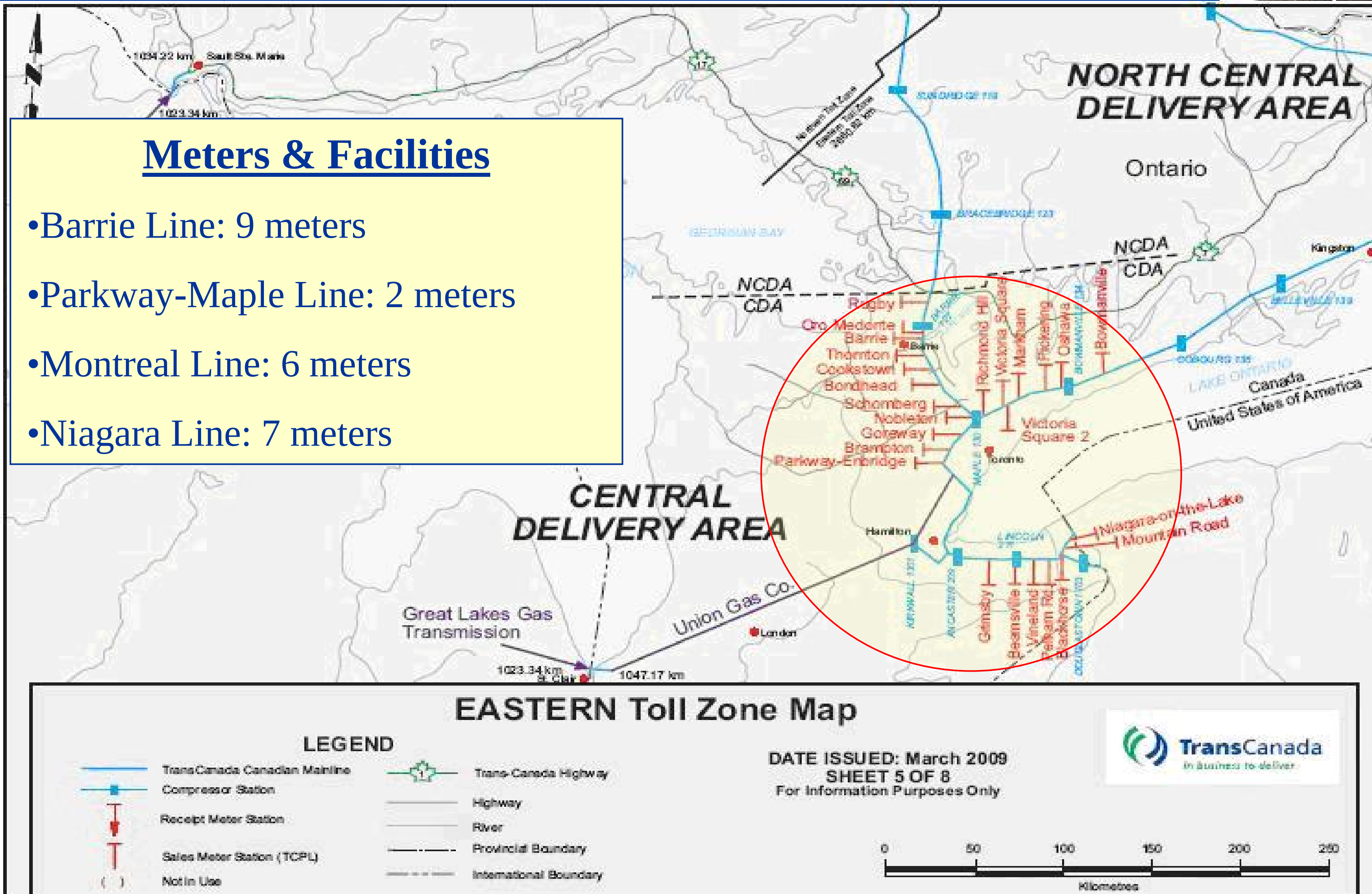
- Montreal Line: 7 meters
- Ottawa Lateral: 3 meters
- NB Shortcut: 6 meters

TransCanada

Enbridge’s Markets Served by TransCanada:
- Enbridge CDA

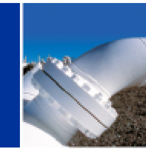
Meters & Facilities

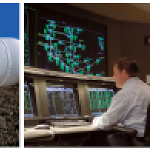
- Barrie Line: 9 meters
- Parkway-Maple Line: 2 meters
- Montreal Line: 6 meters
- Niagara Line: 7 meters



TransCanada

Risk associated with large DDA's





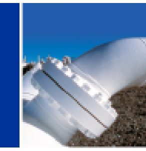
- **Contracts, nominations, capacity allocation ….all done on DDA basis**
- **Localized outage affecting any part of the DDA …..will result in restrictions to full DDA**

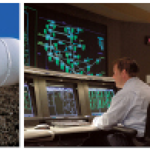
- **Example:**
  - Outage on Barrie Line affecting flows down into the GTA
  - TransCanada would restrict deliveries (based on Tariff service priorities) to all of the Enbridge-CDA including the Niagara Line

- **Large DDAs spanning large geographic areas and multiple segments of the TransCanada System are more likely to be impacted by outages**

TransCanada

Capacity for Discretionary Services - Average Days



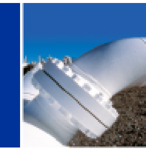


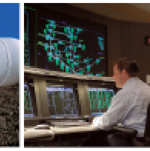
- **TransCanada does not build, nor does it reserve capacity or facilities for Discretionary Services (STFT, Diversions / Alternate Receipts, IT)**
- **Capacity available for Discretionary Services will be reduced by:**
  - Efficiency measures (e.g. compressor unit retirements)
  - Incremental Firm Contracts (e.g. power generation)
  - Other uses (e.g. Keystone)
  - Planned maintenance

Shippers should typically have adequate time to assess impact and respond

TransCanada

Higher Risks on “Extreme” Days – January 09





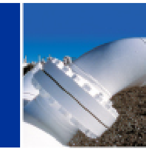
- **Impact of extreme weather on the Northern Ontario Line**
  - 8 unplanned unit outages – reduced capacity by approx. 600 TJ/d
  - Several units failed to start
  - Frozen recycle valves, frozen isolation valves…
  - Effect of outages compounded by geographic proximity

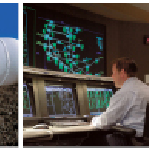
- **Impact of extreme weather on the Prairies Line**
  - 5 unplanned unit outages
  - Several units failed to start
  - Frozen recycle valves, frozen isolation valves…

- **Risk compounded by flow volatility …..**
  - Low flows followed by extreme cold requires numerous unit starts

TransCanada

Two Risks Factors During Extreme Conditions





1) Will capacity be available?

- Outages, frozen valves, and difficulty in starting units
- Firm shippers will nominate full contract entitlements
  - Reduces capacity available for non-firm discretionary services

2) If any capacity is available, how much will you be able to contract?

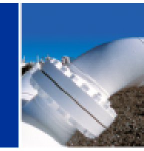
- Will be competing with other markets
- Allocation of new Interruptible nominations and new STFT contracts is based on <u>**sealed-bid auction process**</u>.

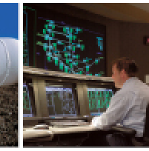
TransCanada

Capacities On TransCanada

TransCanada
In business to deliver

How Does TransCanada Design Its System?





- TransCanada designs its system to meet the daily contract quantity specified in long term firm contracts (FT, STS, FT-SN) during periods of peak demand even with loss of the single most critical compressor unit

- For the following tables:

  "All facilities" = no planned maintenance or unplanned outages

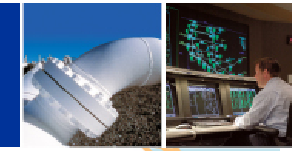
  "Firm" = Design conditions; loss of critical unit

Capacity on TransCanada

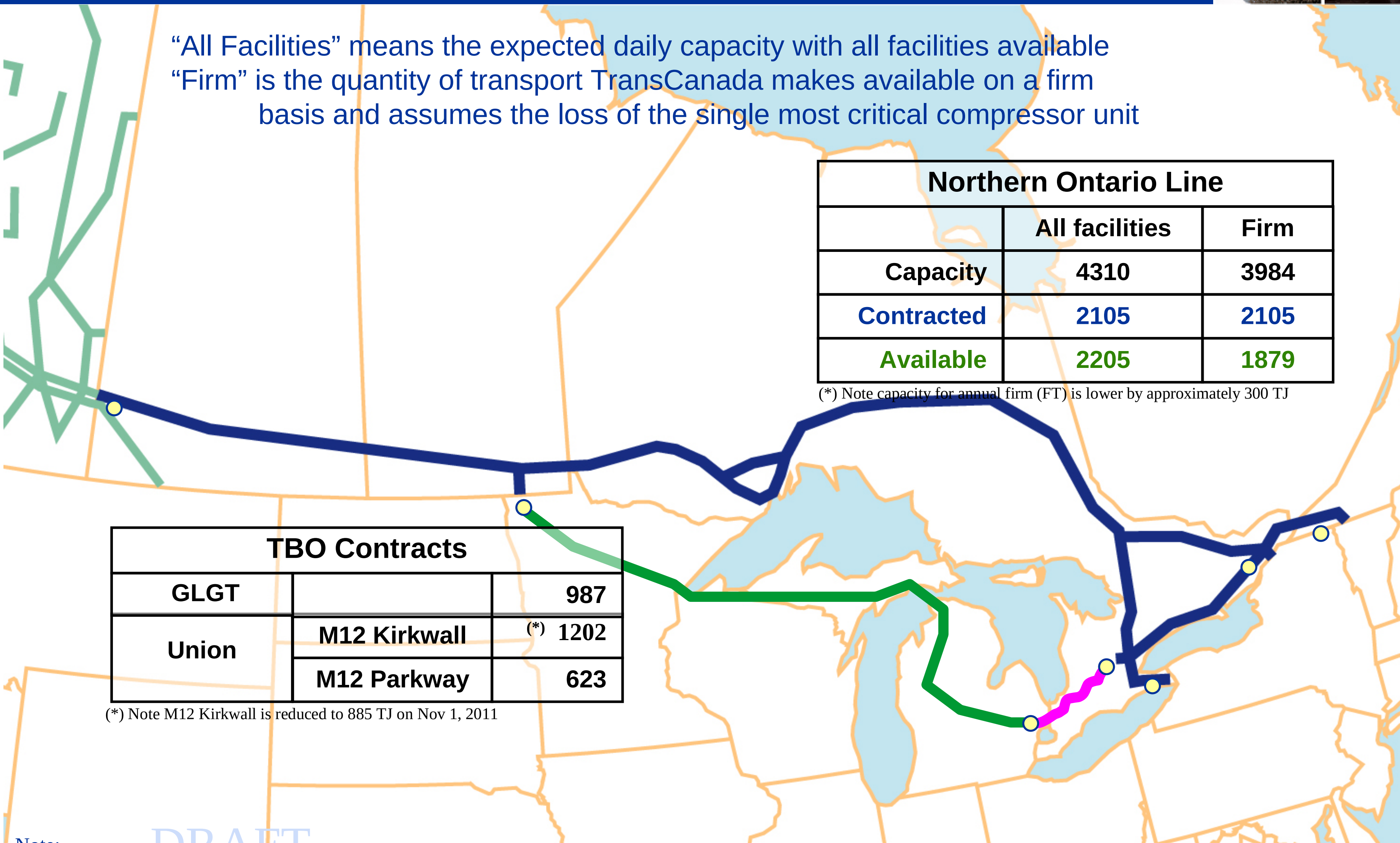
What is available next winter?

TransCanada

Canadian Mainline Capacity Summary (TJ) Winter 2010



"All Facilities" means the expected daily capacity with all facilities available
"Firm" is the quantity of transport TransCanada makes available on a firm basis and assumes the loss of the single most critical compressor unit



Northern Ontario Line		
	All facilities	Firm
Capacity	4310	3984
Contracted	2105	2105
Available	2205	1879

(*) Note capacity for annual firm (FT) is lower by approximately 300 TJ

TBO Contracts		
GLGT		987
Union	M12 Kirkwall	(*) 1202
	M12 Parkway	623

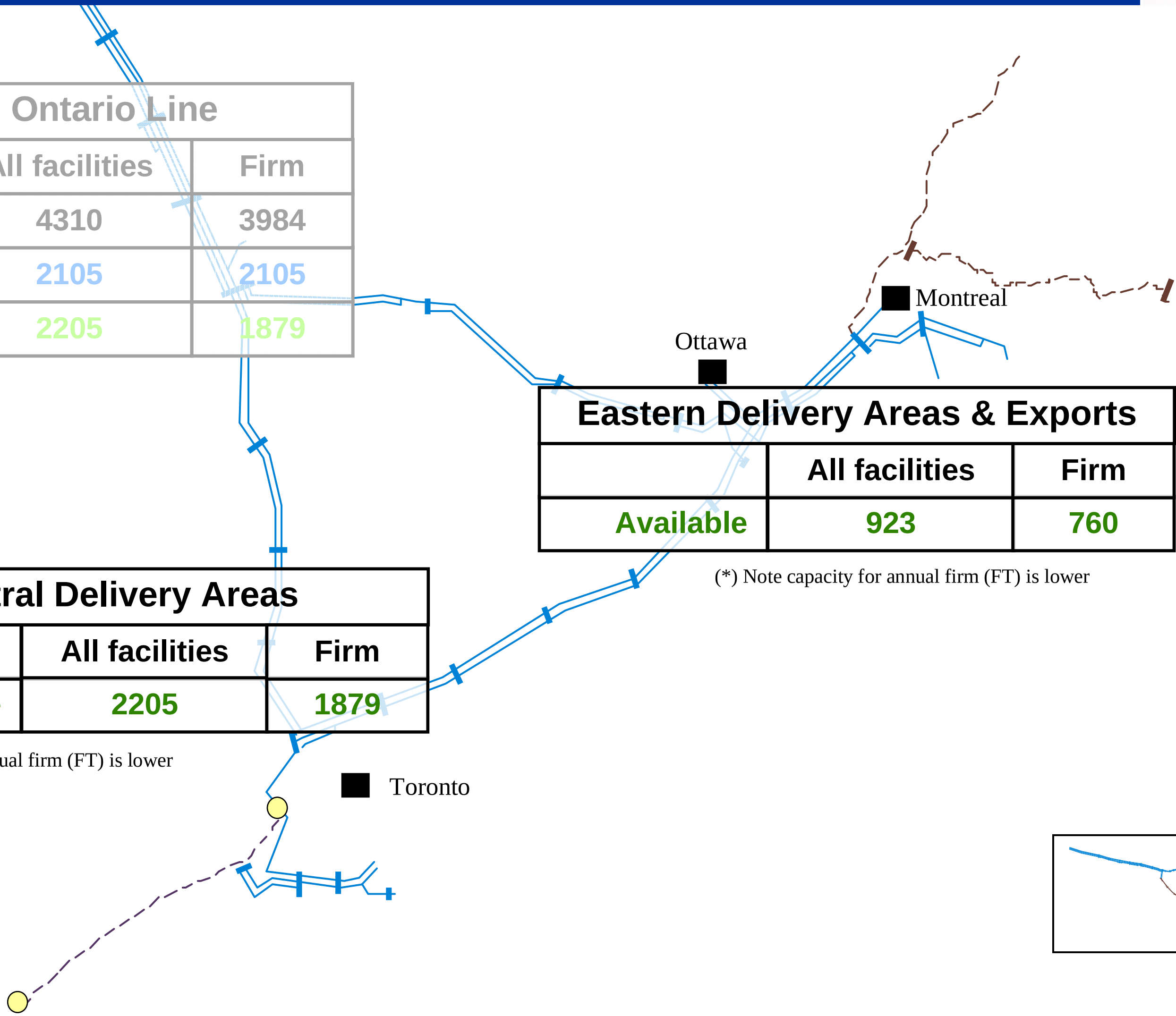
(*) Note M12 Kirkwall is reduced to 885 TJ on Nov 1, 2011

DRAFT

Note:
Based on contracts in effect Nov 1, 2010 assuming full renewal of contracts expiring Oct 31, 2010 (6 month renewal notice required)

TransCanada

Available Capacity in the Market Areas (TJ) Winter 2010



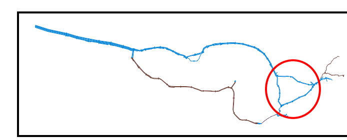
Northern Ontario Line		
	All facilities	Firm
Capacity	4310	3984
Contracted	2105	2105
Available	2205	1879

Eastern Delivery Areas & Exports		
	All facilities	Firm
Available	923	760

(*) Note capacity for annual firm (FT) is lower

Central Delivery Areas		
	All facilities	Firm
Available	2205	1879

(*) Note capacity for annual firm (FT) is lower



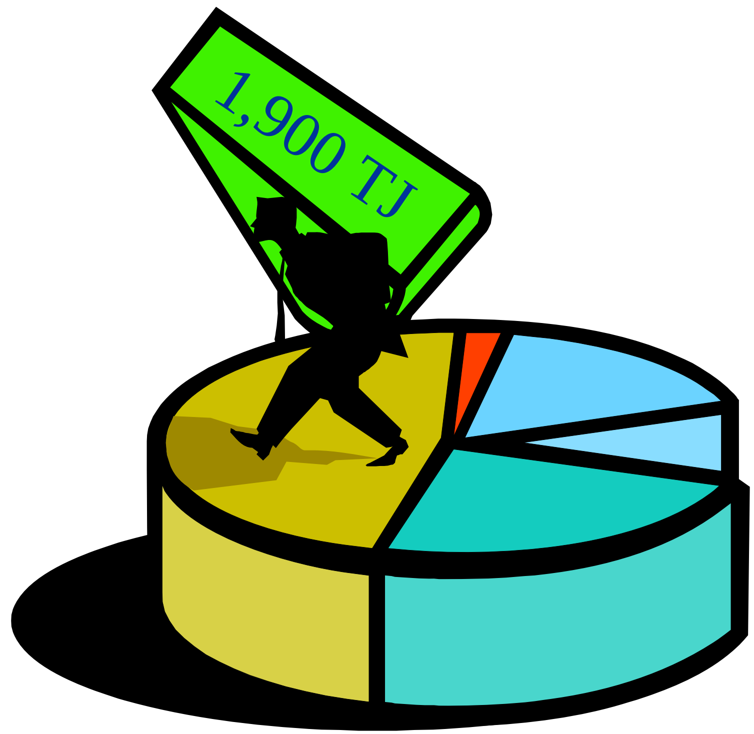
Note:
Based on contracts in effect Nov 1, 2010 assuming full renewal of contracts expiring Oct 31, 2010 (6 month renewal notice required)

TransCanada

Capacity on TransCanada

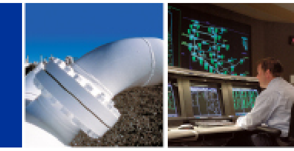
We've seen what's available on TransCanada…

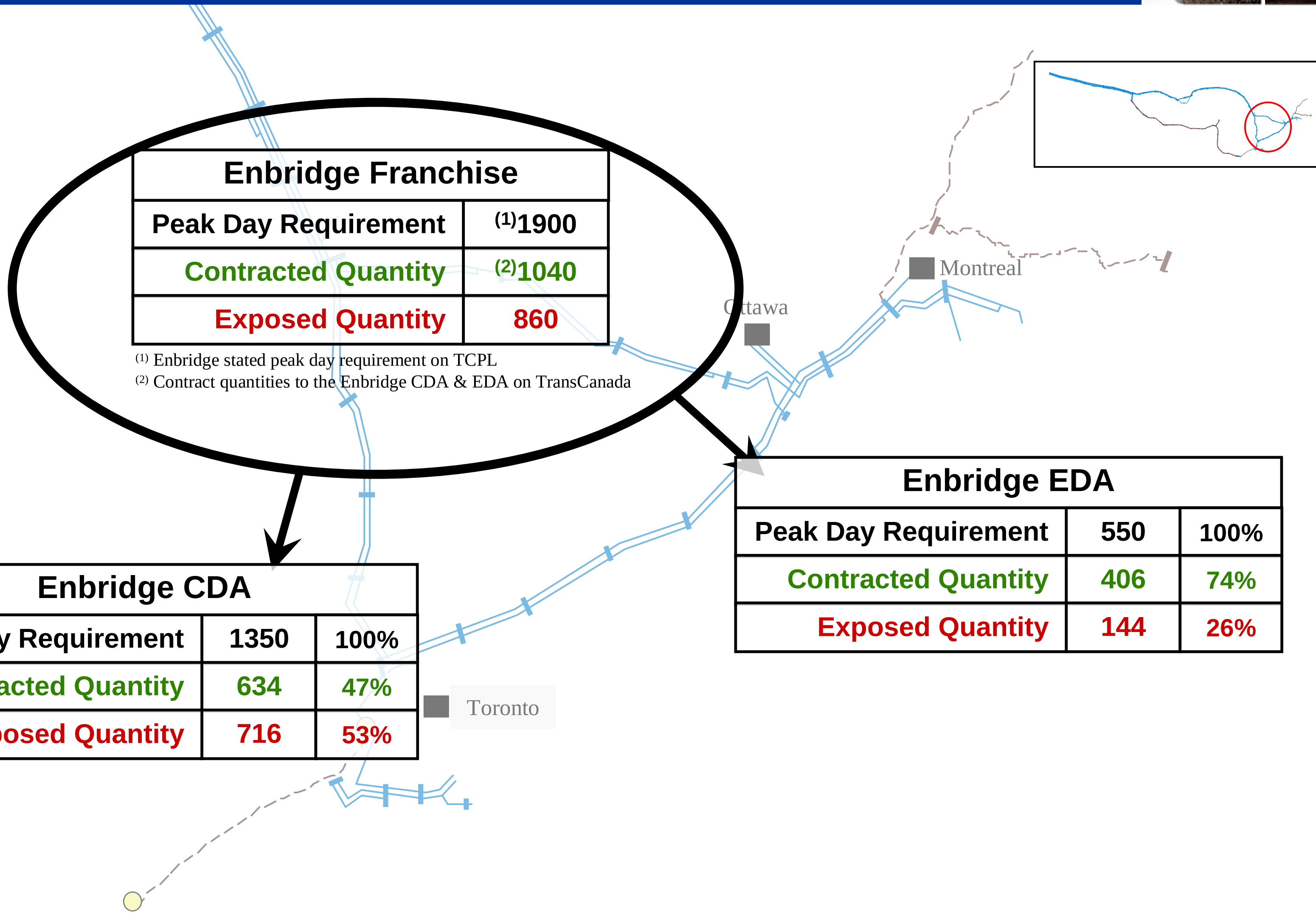
What does Enbridge require?



TransCanada

Enbridge Requirement on TransCanada (TJ)





Enbridge Franchise	
Peak Day Requirement	(1)1900
Contracted Quantity	(2)1040
Exposed Quantity	860

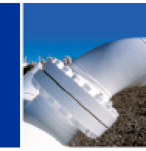
(1) Enbridge stated peak day requirement on TCPL
(2) Contract quantities to the Enbridge CDA & EDA on TransCanada

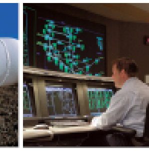
Enbridge CDA		
Peak Day Requirement	1350	100%
Contracted Quantity	634	47%
Exposed Quantity	716	53%

Enbridge EDA		
Peak Day Requirement	550	100%
Contracted Quantity	406	74%
Exposed Quantity	144	26%

TransCanada

Enbridge Requirement on TransCanada





We’re going to look at a couple different capacity and allocation scenarios on TransCanada and how this might affect the market areas

All facilities – Max Daily Capacity (all facilities available)

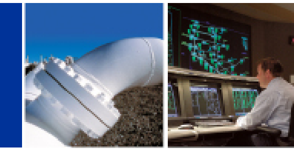
Firm - Design Condition (loss of single most critical unit)

Multiple Unit failure – 600 TJ impact

Multiple Unit Failure / Line Break – 1770 TJ impact

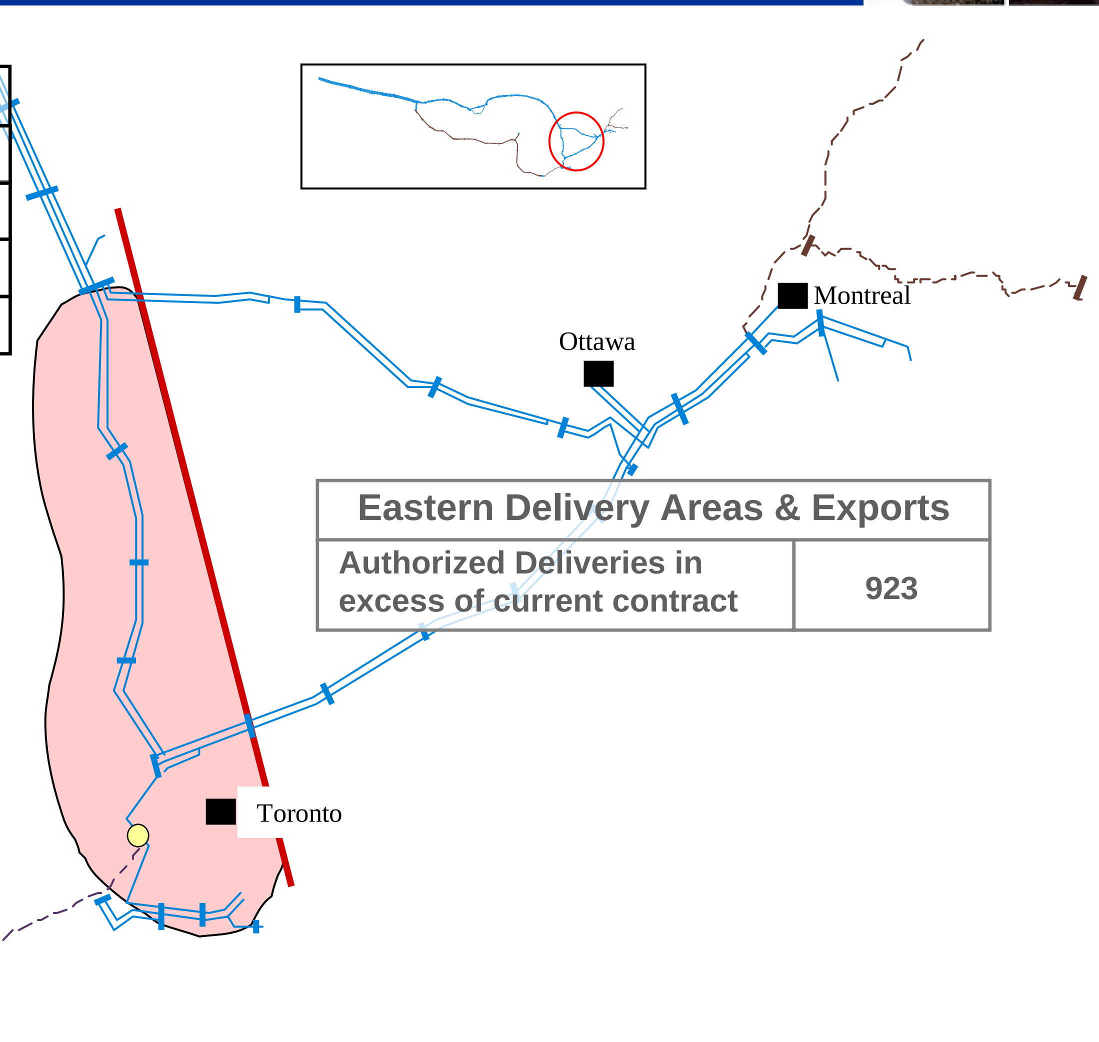
TransCanada

Winter 2010 – At Design Capacity (TJ)
What remains for the CDA if Downstream Markets Peak?



Northern Ontario Line		
	All facilities	Firm
Available	2205	1879
Less EDA	(923)	(923)
Available to CDA	1282	956

Enbridge CDA	
Exposed Quantity	716



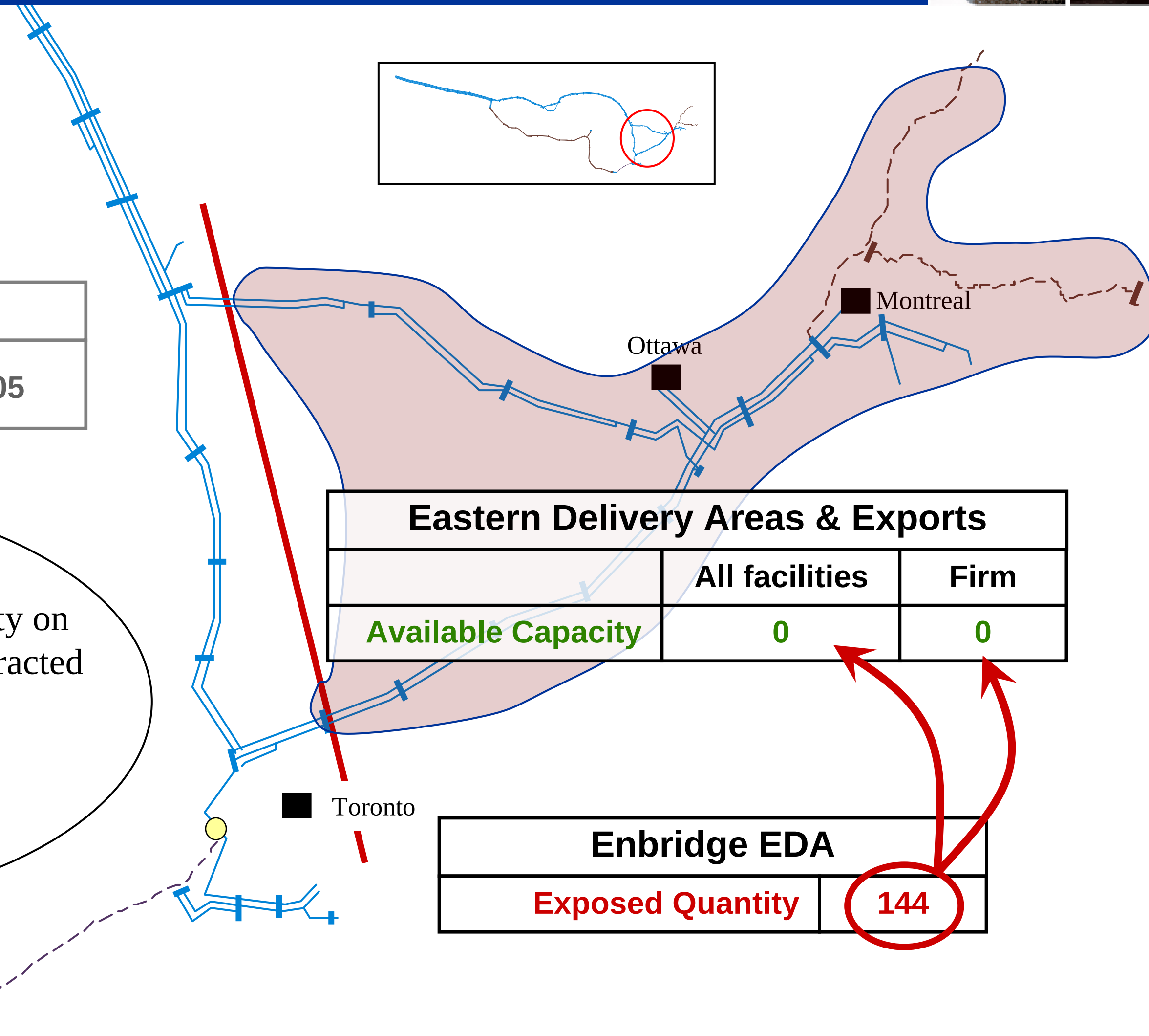
Eastern Delivery Areas & Exports	
Authorized Deliveries in excess of current contract	923

- Capacity is available to the CDA
- Enbridge Shippers must compete

Note:
All Figures in TJ/d
Firm Capacities listed are available for the winter season. Annual FT may be lower
Figures are based on contracts in place as of February 10, 2010 and effective for Nov 1, 2010

TransCanada

Winter 2010 – At Design Capacity (TJ)
What remains for the EDA if the CDA is fully allocated?



Central Delivery Areas	
Authorized Deliveries in excess of current contract	2205

Eastern Delivery Areas & Exports		
	All facilities	Firm
Available Capacity	0	0

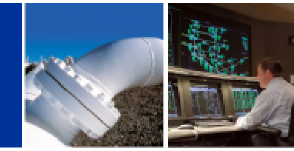
Enbridge EDA	
Exposed Quantity	144

- There is sufficient pipeline capacity on TransCanada to deliver all uncontracted NOL capacity to the CDA leaving nothing available for the EDA
- Enbridge Shippers must compete

Note:
All Figures in TJ/d
Firm Capacities listed are available for the winter season. Annual FT may be lower
Figures are based on contracts in place as of February 10, 2010 and effective for Nov 1, 2010

TransCanada

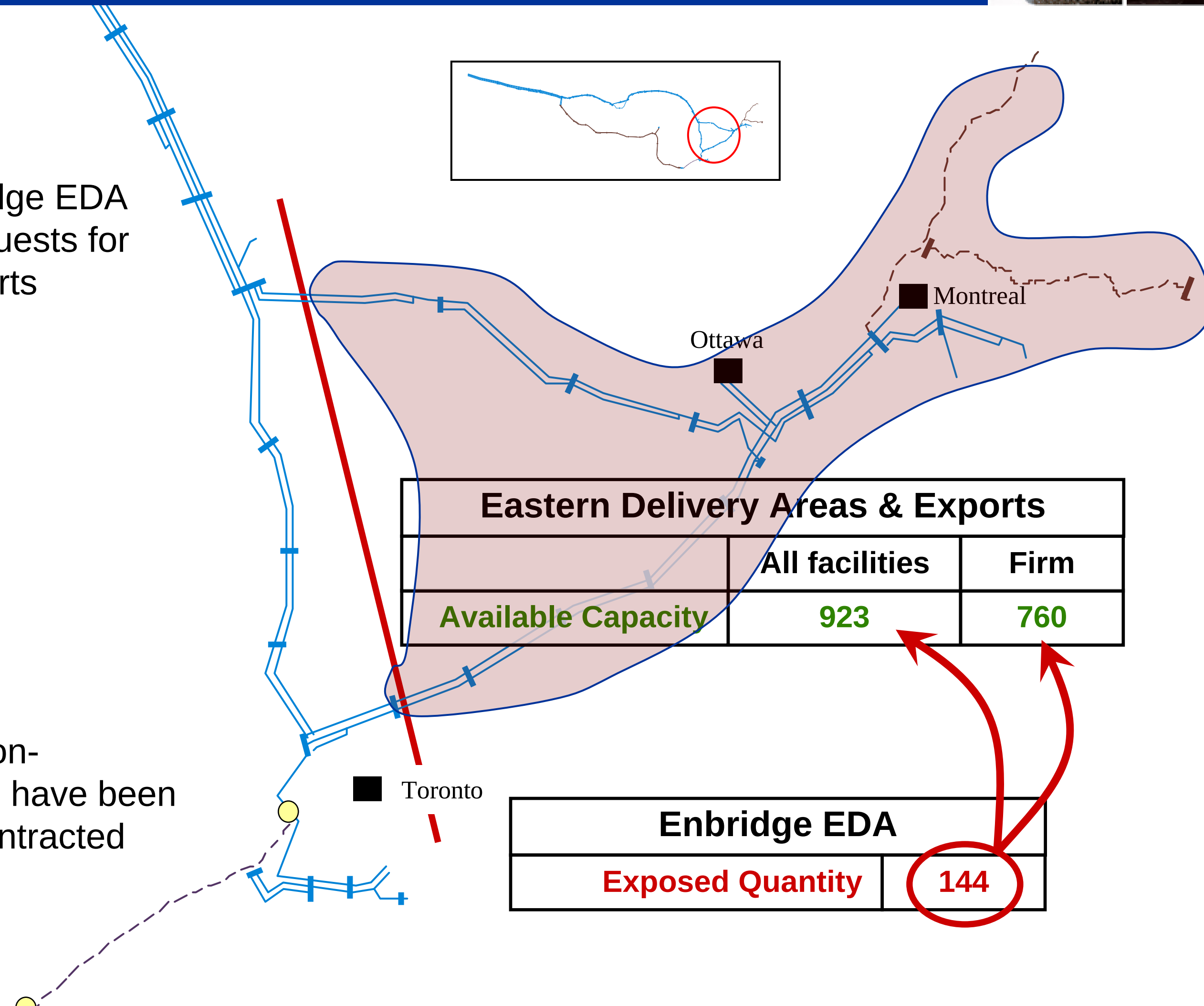
Winter 2010 – At Design Capacity Competing for Capacity Within the EDA



Non firm deliveries to the Enbridge EDA must compete with all other requests for capacity within the EDA & Exports

- Enbridge EDA
- Union EDA
- GMi EDA
- Iroquois
- East Hereford
- Philipsburg
- Napierville
- Cornwall

Excluding Enbridge EDA, the non-coincidental peak day deliveries have been sufficient to consume all non-contracted capacity to the EDA



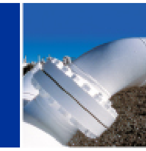
Eastern Delivery Areas & Exports		
	All facilities	Firm
Available Capacity	923	760

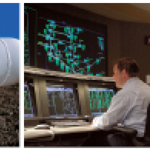
Enbridge EDA	
Exposed Quantity	144

Note:
All Figures in TJ/d
Firm Capacities listed are available for the winter season. Annual FT may be lower
Figures are based on contracts in place as of February 10, 2010 and effective for Nov 1, 2010

TransCanada

Operational Capacity vs Design Capacity





We've looked at TransCanada's design capacities

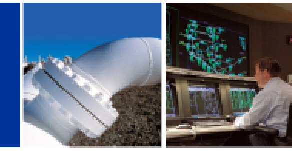
What about maintenance? or upsets?

Let's look at 2 cases:

- A capacity reduction similar to the reduced capacity seen in the January 2009 cold snap (600 TJ)
- A capacity reduction similar to the reduced capacity seen in the September 2009 line break (1770 TJ)

TransCanada

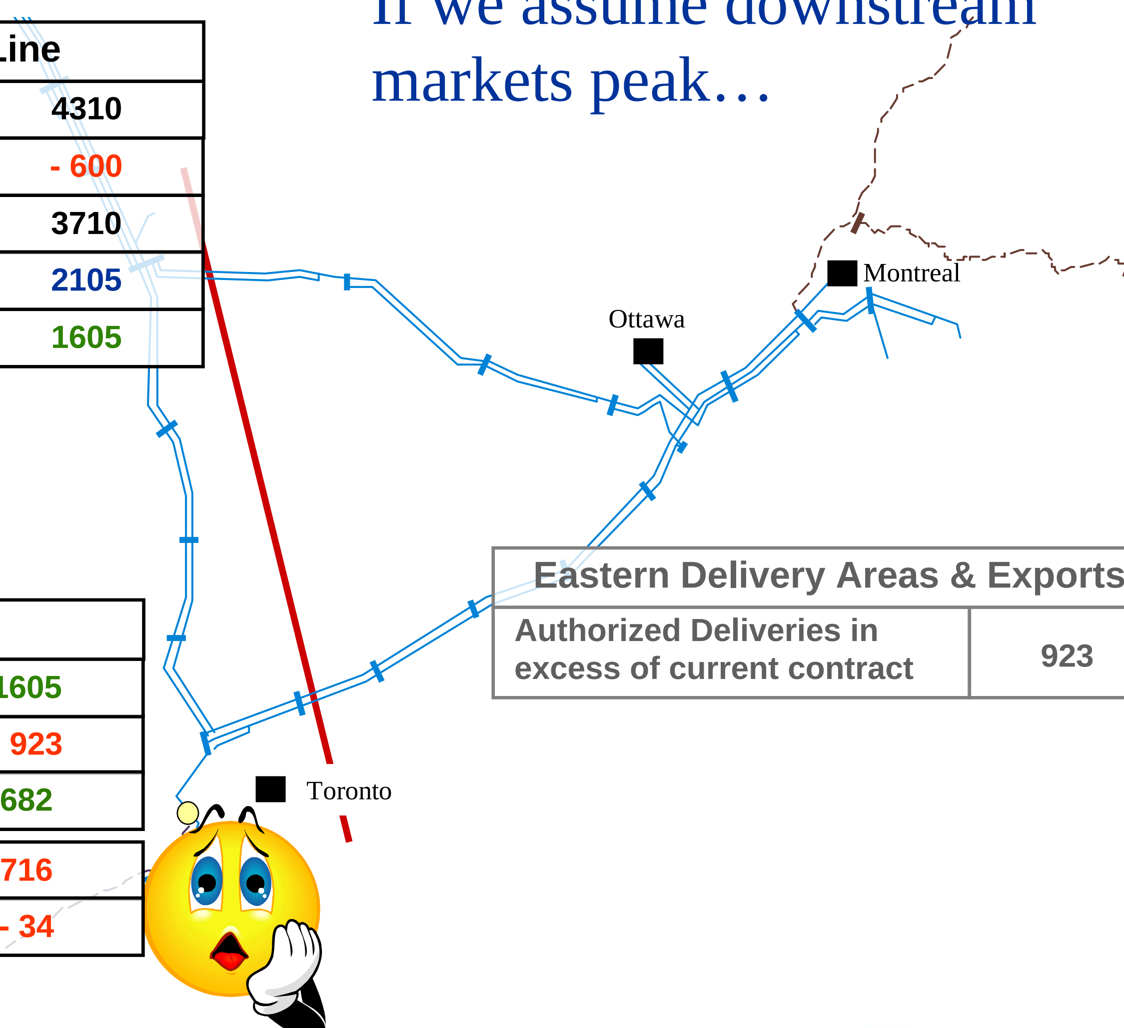
600 TJ Reduction in NOL Capacity



Reduced Capacity Scenario

Northern Ontario Line	
Capacity with all facilities	4310
Less Outage Scenario	- 600
Capacity	3710
Contracted	2105
Available	1605

If we assume downstream markets peak…



Eastern Delivery Areas & Exports	
Authorized Deliveries in excess of current contract	923

Enbridge CDA	
Available through NOL	1605
Less Gas to D/S Markets	- 923
Available to CDA	682
EGD CDA Exposed Qty	716
Shortfall	- 34

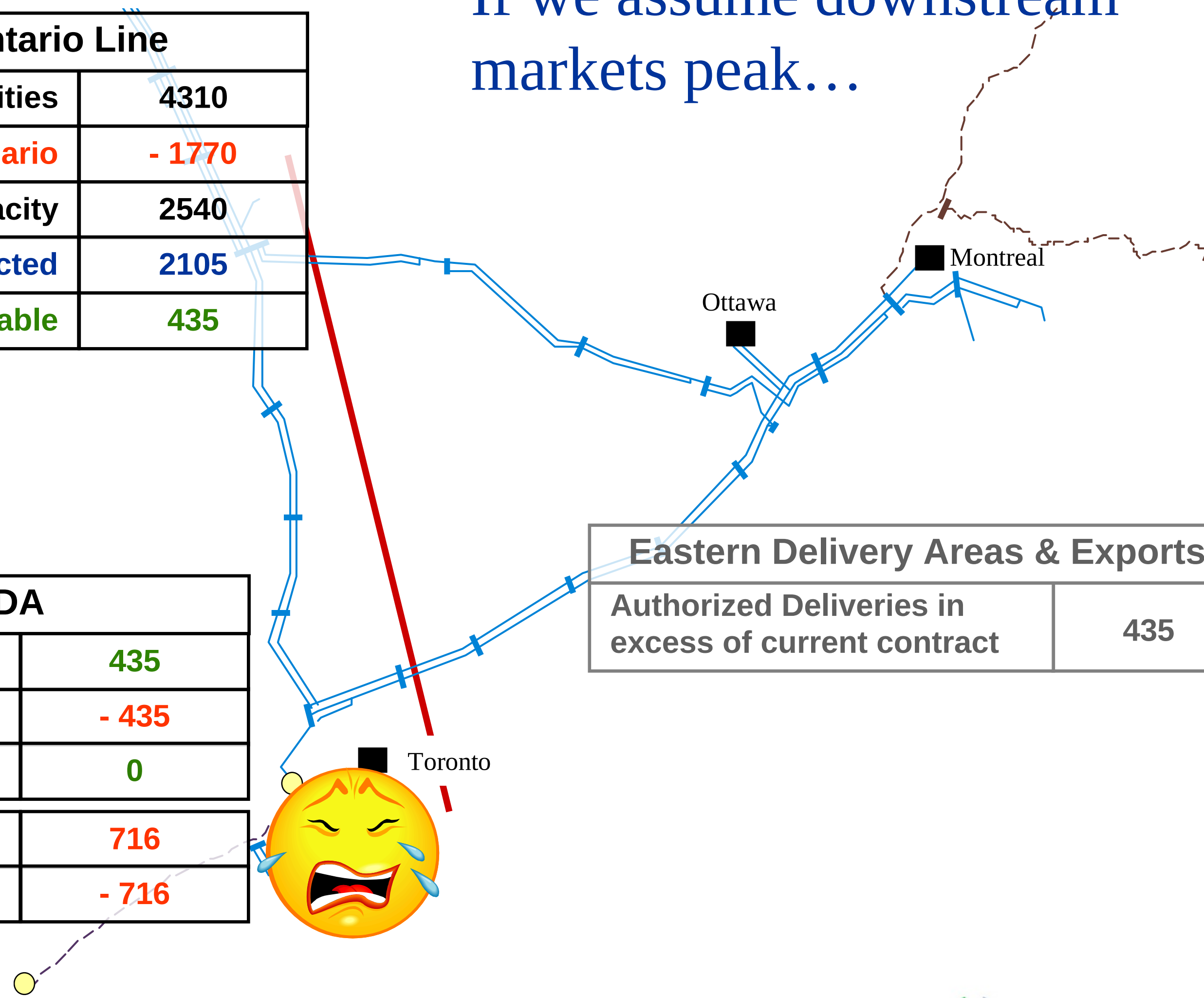
TransCanada

1770 TJ Reduction in NOL Capacity

Reduced Capacity Scenario

Northern Ontario Line	
Capacity with all facilities	4310
Less Outage Scenario	- 1770
Capacity	2540
Contracted	2105
Available	435

If we assume downstream markets peak…



Eastern Delivery Areas & Exports	
Authorized Deliveries in excess of current contract	435

Enbridge CDA	
Available through NOL	435
Less Gas to D/S Markets	- 435
Available to CDA	0
EGD CDA Exposed Qty	716
Shortfall	- 716

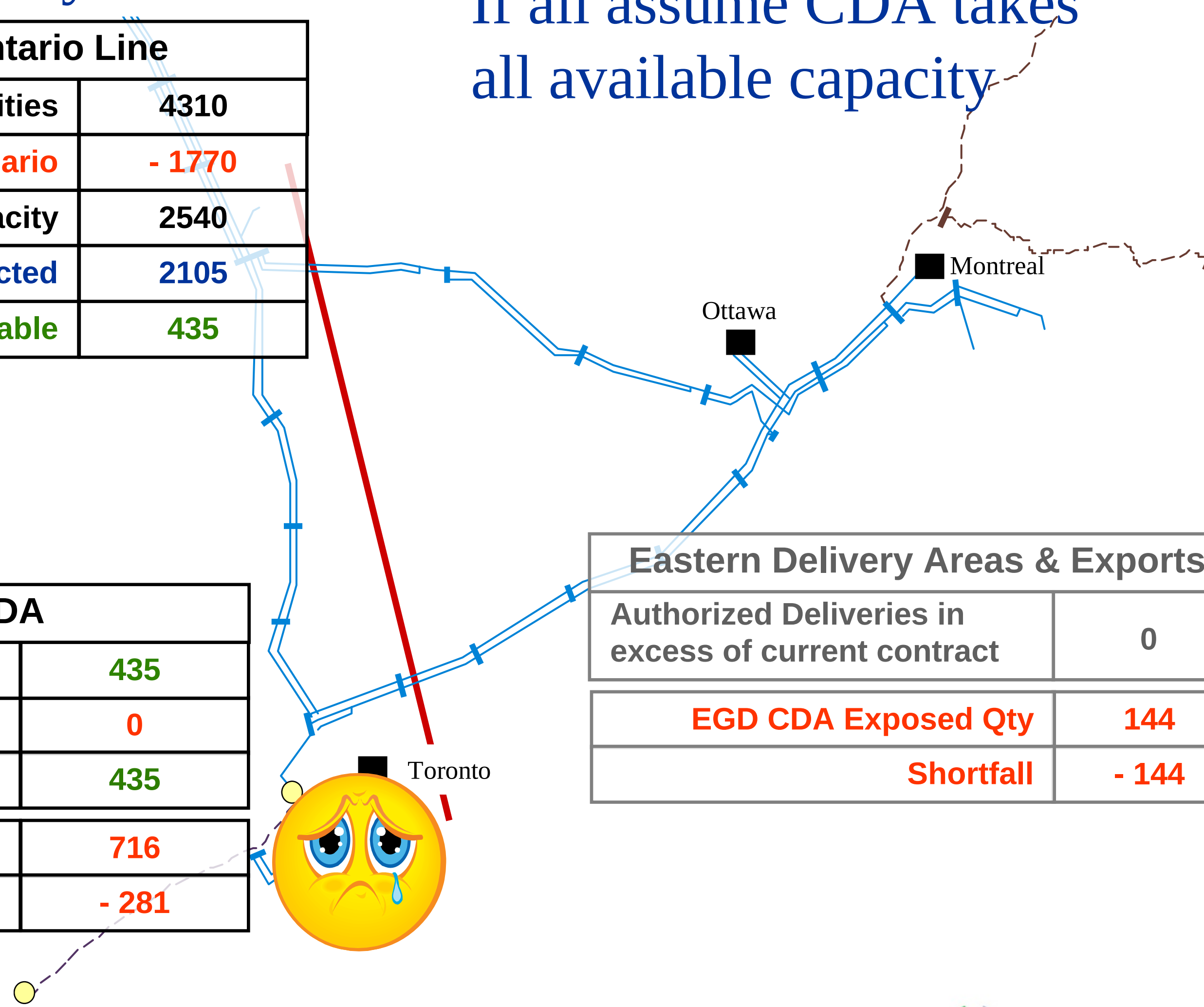
TransCanada

1770 TJ Reduction in NOL Capacity (…2)

Reduced Capacity Scenario

Northern Ontario Line	
Capacity with all facilities	4310
Less Outage Scenario	- 1770
Capacity	2540
Contracted	2105
Available	435

If all assume CDA takes all available capacity



Enbridge CDA	
Available through NOL	435
Less Gas to D/S Markets	0
Available to CDA	435

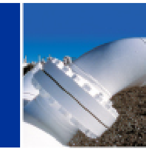
EGD CDA Exposed Qty	716
Shortfall	- 281

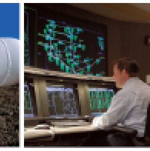
Eastern Delivery Areas & Exports	
Authorized Deliveries in excess of current contract	0

EGD CDA Exposed Qty	144
Shortfall	- 144

TransCanada

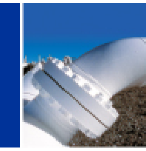
What does this all mean?

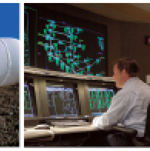




- **All facilities available**
  - Capacity available to Enbridge CDA & EDA
  - Must compete for capacity, more of an issue in the EDA
- **Firm (with loss of critical unit)**
  - Less capacity available to Enbridge CDA & EDA
  - Must compete for capacity
- **Extreme day: impact on non-firm services**
  - Jan/09 (600 TJ capacity loss): CDA could be restricted
  - Sept/09 Line Break (1,770 TJ capacity loss): CDA & EDA could be severely restricted
  - Union outage: Impact? 2.5 Bcf?

TransCanada





Probability of an Outage

Unable to establish a probability of an outage, since insufficient data on starting multiple units in extreme weather

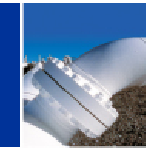
- **If the outage occurs during an average day:**
  - The impact on deliveries may be minimal (or none in the case of the Sept 09 line break)
- **If the outage occurs during periods of extreme cold weather:**
  - The impact on deliveries can be significant
  - There is increased likelihood of facilities failing
- **If an outage occurs:**
  - Non-firm discretionary services would be cut to zero before any firm services are impacted; and
  - If firm is impacted, such cuts would be made on a prorata basis.

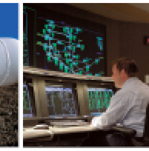
TransCanada

January 2009 Cold Snap

TransCanada
In business to deliver

Highlights



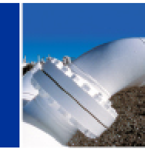


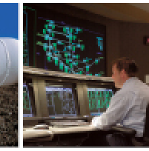
- **All available long haul STFT sold out**
- **High EDA deliveries ~ 3.1 bcf**
- **High NOL flows driven by reduced Overrun on Union of 500 mmcfd**
- **Multiple System Bottlenecks:**
  - East Hereford at Capacity – discretionary authorized every day
  - Chippawa at Capacity - New record set at 690 MMcfd
  - Prairies Line restricted on 14th
  - GMi EDA at capacity on 15th
  - NOL at capacity and restricting on 15th and 16th

All Firm Services Met

TransCanada

Prairies Line

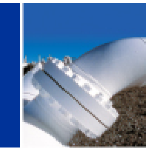


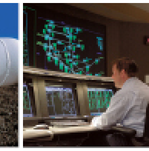


- **Extreme cold temperatures across the Prairies**
  - -35C in the west
- **Actions**
  - Cancelled 3 planned outages ~ 60 MW
  - Started 14 compressors totaling ~ 210 MW
- **Impact of extreme weather on the Prairies Line**
  - 5 unplanned unit outages
  - Several units failed to start
  - Frozen recycle valves, frozen isolation valves...

TransCanada

Northern Ontario Line

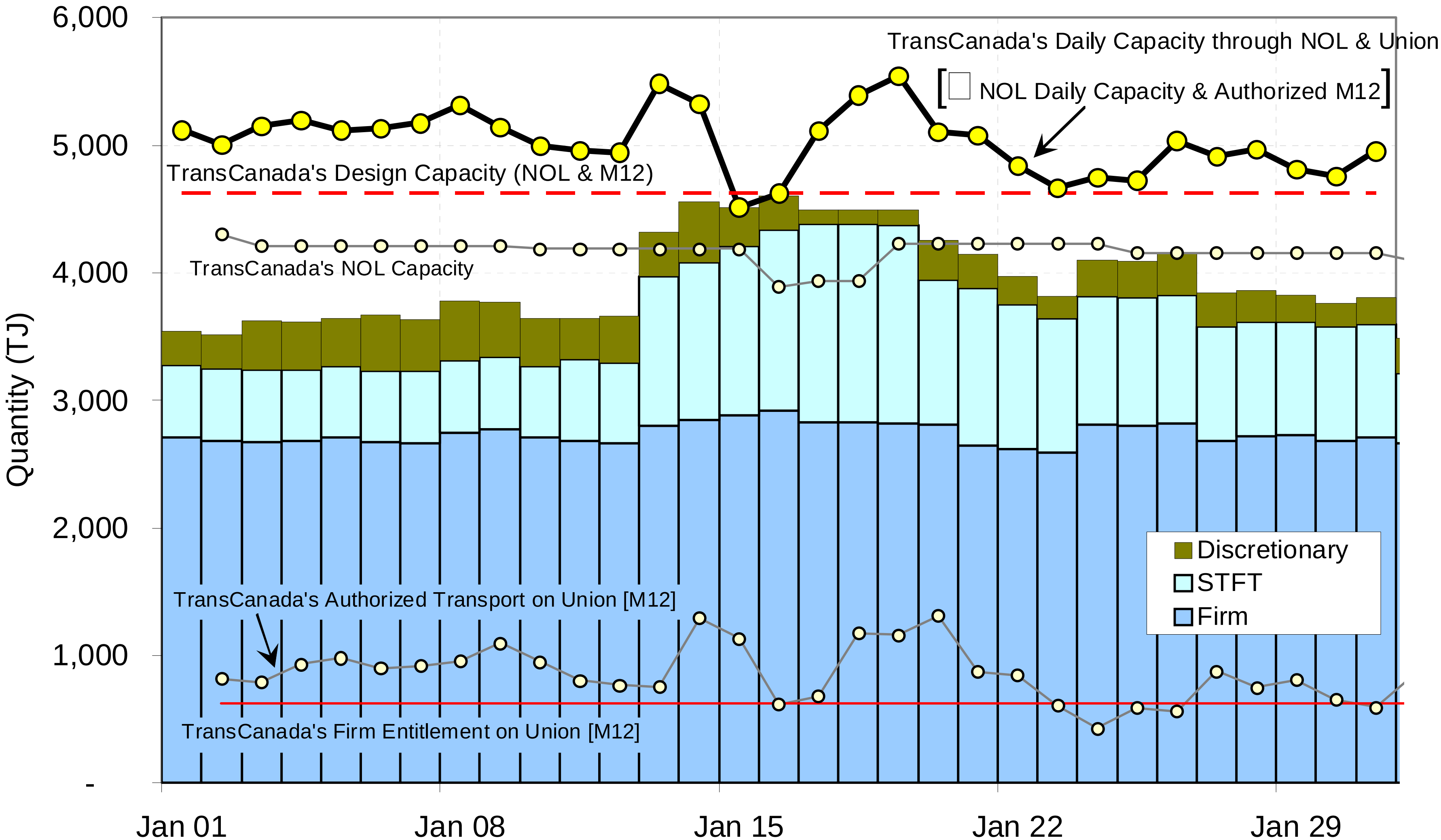




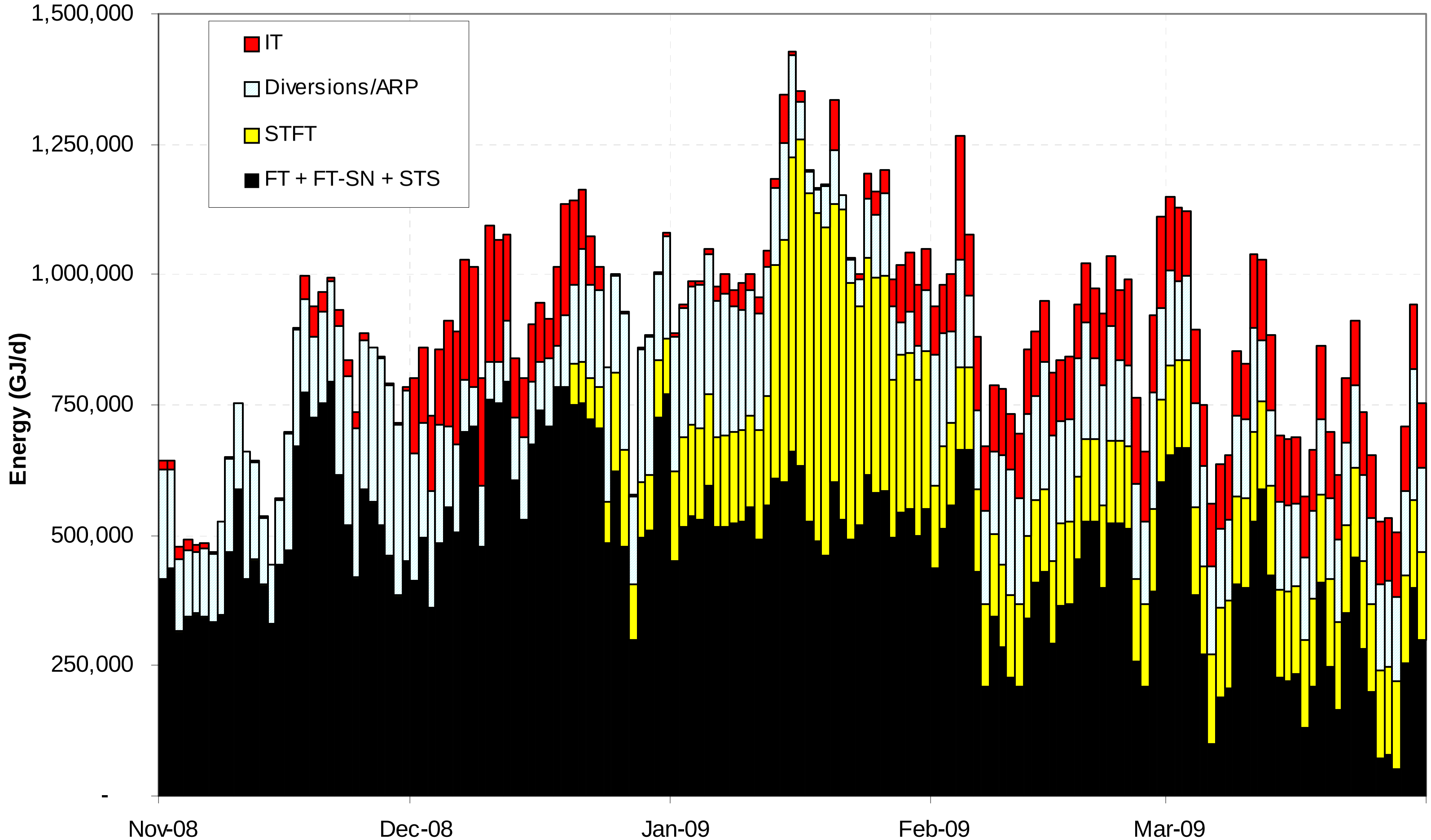
- **Extreme cold weather across the Northern Ontario Line**
  - -43C in Northern Ontario
  - -31C in Ottawa
- **Actions**
  - Expedited completion of 3 outages ~ 80 MW
  - Started 18 compressors totaling ~ 400 MW
- **Impact of extreme weather on the Northern Ontario Line**
  - 8 unplanned unit outages – reduced capacity by approx. 600 TJ/d
  - Several units failed to start
  - Frozen recycle valves, frozen isolation valves...
  - Effect of outages compounded by geographic proximity

TransCanada

Capacities & Services
- January 1-31



Deliveries to the Enbridge CDA*
- Winter 2008/2009



*** Includes Enbridge CDA, Goreway CDA, Victoria #2 CDA**

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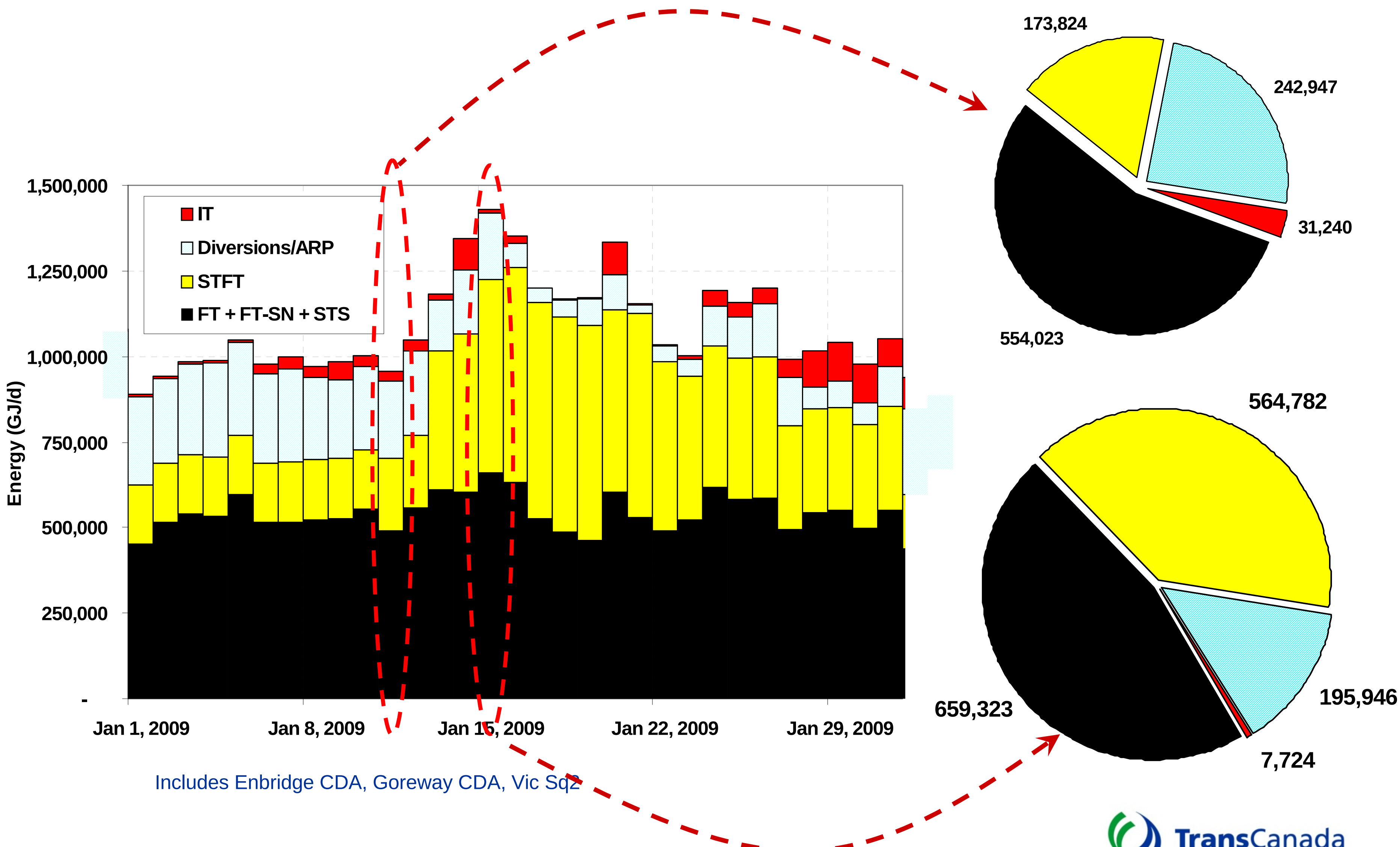
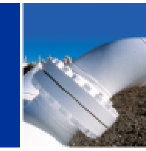
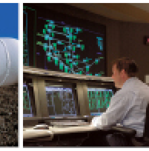
Deliveries to the Enbridge CDA*
- January 2009



Includes Enbridge CDA, Goreway CDA, Vic Sq2

IT & Diversion Nominations to Enbridge
- January 15, 2009, Timely Nomination Cycle





Enbridge CDA Service Category	Quantity Nominated (GJ)	Quantity Authorized (GJ)	% Authorized	Quantity Not Authorized (GJ)
IT –not through bottleneck	4,653	4,653	100%	0
IT – through bottleneck	5,306	0	0%	5,306
Diversions – Upstream	167,253	167,253	100%	0
Diversions – Downstream	73,166	40,873	55.9%	32,293

Enbridge EDA Service Category	Quantity Nominated (GJ)	Quantity Authorized (GJ)	% Authorized	Quantity Not Authorized (GJ)
IT – not through bottleneck	498	498	100%	0
IT – through bottleneck	24,433	0	0%	24,433
Diversions – Upstream	150,016	150,016	100%	0
Diversions - Downstream	21,735	12,143	55.9%	9,592

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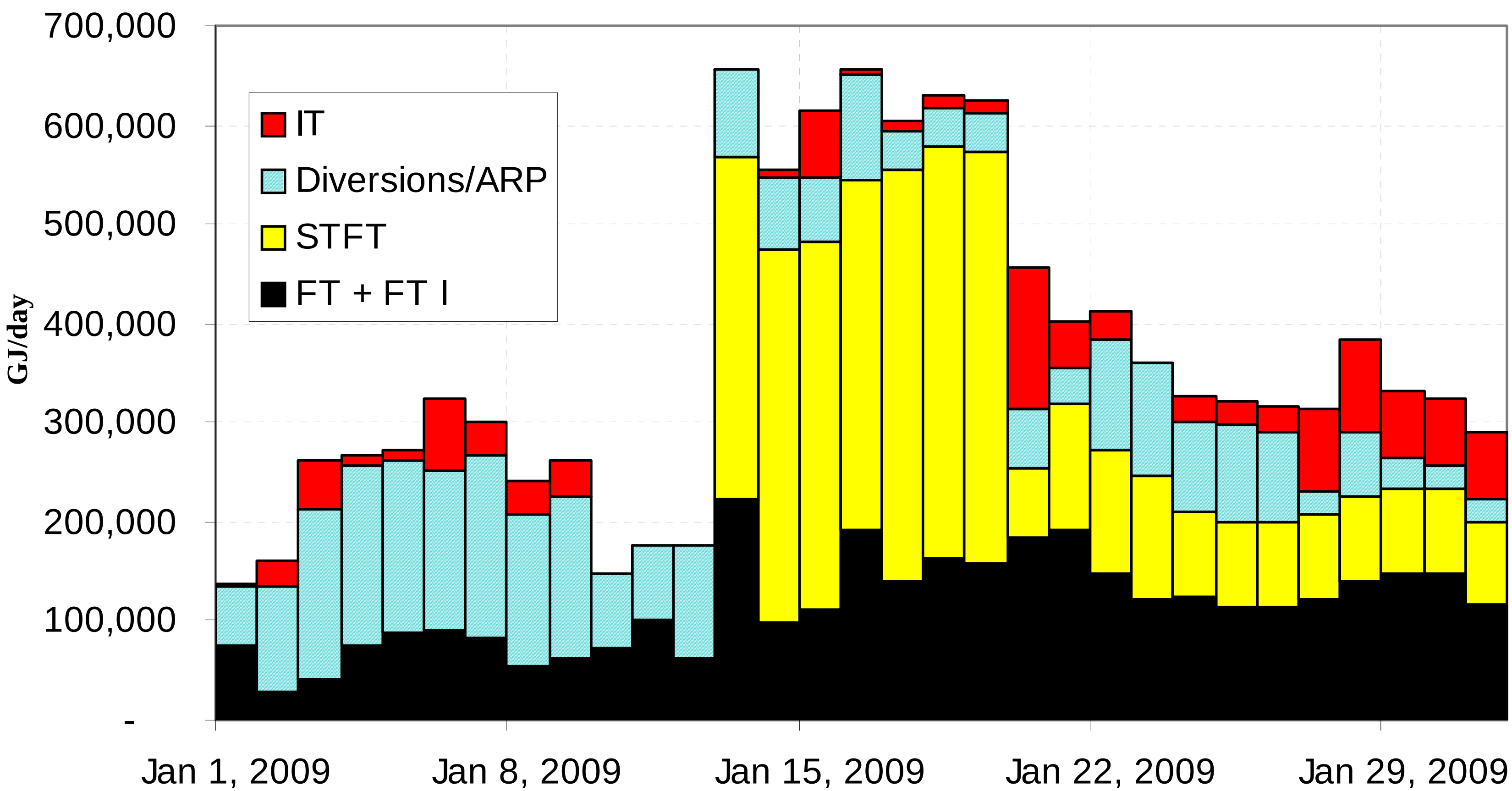
Deliveries to the Union CDA



Capacity & Service

Options to Serve Enbridge Markets

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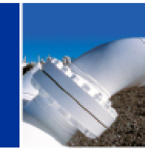
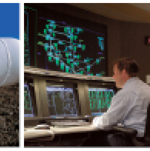
Options

- **FT from Empress = Low Risk**
  - Lots of capacity available
  - Excellent supply availability
- **STFT from Empress = Low Risk if contracted for full winter**
  - Lots of capacity available <u>if contracted before extreme day</u>
  - Excellent supply availability
- **FT or STFT from North Bay**
  - Supply availability?   Need partner with upstream firm transport

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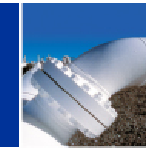
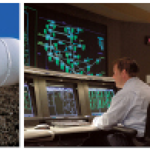
Options





- **FT or STFT from Dawn**
  - Capacity may be available
    - Subject to backhaul/exchange….with flow through Northern Ontario Line
  - Good supply availability

- **Upstream Diversion**
  - Capacity is “firm” for upstream diversions
    - Example:
      - Diversion to CDA from FT contract that delivers to Iroquois, East Hereford or EDA should typically be “upstream” and “firm”
      - Depends on location of bottleneck(s)
  - Requires “deal” with FT contract holder

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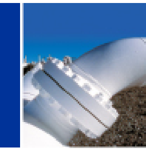
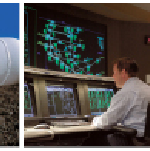
Options





- **Downstream Diversions = High Risk**
  - Limited or no capacity available on "extreme" days
  - Prorata allocation if any capacity is available
- **IT = High Risk**
  - Limited or no capacity available on "extreme" days
  - Must compete in bidding process for any capacity that is available

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Summary

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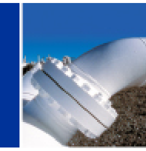
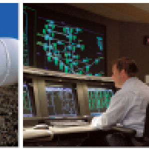
Summary - Capacities





- **All facilities available**
  - Capacity available to Enbridge CDA & EDA
  - Must compete for capacity, more of an issue in the EDA
- **Firm (with loss of critical unit)**
  - Less capacity available to Enbridge CDA & EDA
  - Must compete for capacity
- **Extreme day: impact on non-firm services**
  - Jan/09 (600 TJ capacity loss): CDA could be restricted
  - Sept/09 Line Break (1,770 TJ capacity loss): CDA & EDA could be severely restricted
  - Union outage: Impact? 2.5 Bcf?

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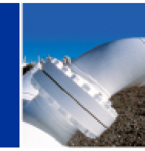
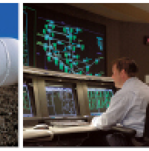
Summary - Options





- Firm services
  - FT: lowest risk
  - STFT: low risk if contracted before “extreme” day
- Supply sources
  - Empress: excellent supply availability
  - North Bay: need to ensure upstream supply / transport
  - Dawn: capacity may be available
- Upstream Diversion
  - Typically low risk; need FT partner
- Downstream Diversion & IT
  - Risky

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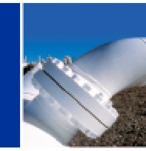
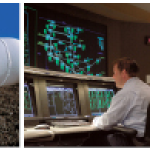
Keep these 6 Factors in mind when assessing risk





1) Upstream grid

- Need to think about risks and capacity constraints on any upstream pipeline...... Union, GLGT, Vector...
- EGD is highly reliant on Union system

2) Service Priority

- Long Term Firm, upstream Diversions and pre-contracted STFT have lowest risk

3) Higher risks of broad Distributor Delivery Areas"DDAs"

- localized constraint = broad impacts

4) Lots of capacity on Average day

5) Risks are higher on "extreme" days

- Impact of extreme cold weather; impact of flow volatility

6) Not just a question of <u>how much</u> capacity; also a question of <u>who</u> gets the capacity that is available.

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Questions?

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Working Committee Notes

Enbridge Gas Distribution Inc.
Working Committee Meeting 4
On
System Reliability

April 8, 2010
Ontario Energy Board
2300 Yonge St., 25th Floor
North Hearing Room

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Enbridge Gas Distribution Inc.
Working Committee Meeting 3
On
System Reliability

1. Opening and Introductory Remarks

Presented by Bob Betts, Facilitator

The meeting was called to order at 9:15 a.m. Bob Betts welcomed all those in attendance.

Bob asked all participants to introduce themselves, and asked Ian Mondrow to introduce Rob Rowe to the members.

Ian indicated that Rob recently retired from Enbridge and was attending in a support role for IGUA with a particular focus on issues of pipeline and pipeline constraints. IGUA felt that with Rob's assistance, IGUA would be able to provide a more robust input on the consultation.

Bob Betts provided the committee with more background to Rob's attendance. He referred first to the initiating call from Ian to himself proposing the idea of having Rob attend the meeting. Bob had indicated to Ian, that it would be Enbridge's decision to make, but he provided Ian with two comments, first that there might be some issue about IGUA having a second representative and it may be considered unfair if IGUA seemed to have a second voice at the working committee meeting, and second, that it would be very important that Rob accept the record "as is" and not make the committee go back over previously covered ground. Another item that was discussed was the potential concerns about funding.

Further to this, Bob made Ian aware of an email from CCC expressing concern about funding, referring to the stakeholder funding proposal to the Board and the position that there would be funding for only one representative of each participating stakeholder. Ian was not copied on the email from CCC and indicated that he would seek clarification from his client on the funding issue. Rob remained in the meeting after this discussion.

Ian Mondrow asked if Enbridge could forward him the copy of the original letter of August 31, 2009 and all of the attachments that went to the Board defining the consultation process. He indicated that he was missing Attachment 4.

2. Request from Dwayne Quinn, FRHPO to Join the Working Committee

Next the committee considered the request of Dwayne Quinn, representing the Federation of Rental Housing Providers of Ontario, (FRHPO), to join the working committee for both System Reliability and Mass Market Unbundling. Dwayne was on the telephone line and offered to give the committee the background to his request.

Dwayne described his extensive history and experience in gas operations and regulations in his past. He indicated his interest in contributing to a better design for regulation of gas distributers with respect to these two issues, while keeping in mind the impact on rates. He indicated that he had read the record from the last three meetings and accepts the record as it stands, and that his participation and questions within this committee would potentially save time versus dealing with the questions later.

Bob informed Dwayne and the committee of a couple of important points related to this request:

- First that Just Energy had made a similar request some time ago and was turned down on the basis that the larger stakeholder committee had selected the working committee to represent them, in the interest of keeping the working committee at an effective size, and that the committee results would be brought back to the larger consultative for discussion;
- Second, BP Canada had asked Bob when they would have an opportunity to get involved again, and Bob asked Peter Exall to allow the working committee to finish their work, which would then lead back to the larger group for discussion.

Both Just Energy and BP accepted those positions.

At this stage, Dwayne left the call and the committee discussed the matter further.

The committee discussed Dwayne's request and concluded that Bob as Facilitator should speak to Dwayne and indicate the committee's "preference" that he not join the working committee at this late stage, when the information gathering phase is largely over and the working committee is about to enter the stage of reaching a conclusion.

The primary reasons were that:

- Others that have been involved from the beginning have asked to join and have been turned down;
- It is too late to bring a new party into the process of searching for a consensus; and
- Dwayne and other interested stakeholders would be welcomed to question and contribute to this issue in the next phase.

The session recessed while Bob called Dwayne Quinn to explain the committee's position. The committee felt it would be most appropriate to relay this position to Dwayne one-on-one, instead of on a conference call.

COMMITTEE BREAK

Bob returned to inform the committee of his discussion with Dwayne Quinn. He said that Dwayne had accepted the committee's decision reluctantly. Dwayne still hoped to be invited back to participate in the working committee's settlement discussions, but Bob explained the two-fold concern that in that scenario he would not have heard the evidence that the other members had heard and therefore would be less effective in the settlement discussions, but more importantly, if he was invited in at that stage, it would only be appropriate to invite all interested parties in. Bob indicated to Dwayne that in his opinion that would not be helpful to the process.

Bob said that Dwayne was very good and indicated he would not want to derail the process, but he will need to talk to his client about this situation.

Dwayne Quinn asked for two things in closing:

- That Enbridge provide a description of how this process will move forward, thereby helping him understand how he will be able to participate in the settlement process; and
- That he be added to the distribution list for any and all materials related to the process.

3. April 8, 2010 Direct Energy – Brad Janzen & Jamie Humble

(A copy of this presentation included in Appendix E)

Brad led the committee through the presentation.

He started on slide 3 by reviewing the quotes for the Board's decision that he felt had been established in that hearing.

He next moved to slide 4 that depicted a graph of the daily prices in the New York City and the Hartford/Worchester gas markets plotted against the variations in temperature around normal conditions. That was compared to the CDA.

The chart showed much greater volatility and variation in the New York market area than in the CDA.

In response to a question from AEGENT he indicated that the temperature variations were based upon the average monthly January temperatures reported at Pearson, over a 30 year period.

Board Staff asked DE what conclusion DE was hoping the committee would draw from this graph. Brad explained that this was aimed to be visualization and that he didn't want the focus to be on the numbers. But the primary point being made here is that when the temperatures decline further away from the 30 year norms, the New York markets showed much greater volatility than the CDA market; concluding that gas prices in the CDA market are far less sensitive to temperature than the New York market. In response to a question by IGUA, DE stated that, in their opinion, this is evidence that the two US markets graphed here are more constrained by gas transport than is the CDA.

IGUA asked Enbridge if it could analyze and comment on the information provided on Slide 3 of DE's presentation. Enbridge said it could, but that it would need to know the details of the numbers, including what they are based on and what they mean.

Malini Giridhar did comment that this graph doesn't really address the issue that is of concern to Enbridge. Enbridge is not arguing that there is a constraint problem in these kinds of normal or reasonably abnormal conditions. Enbridge's concern focuses on the possibility of an unplanned and unpredictable, sudden and substantial restriction on either TCPL or Union, and the fact that Enbridge's non-firm deliveries would be the first to be dropped. The two examples in TCPL's presentation show that these occurrences can happen and have happened recently. So far they have not happened in the in the coldest period of the year.

IGUA was not surprised by Enbridge's position and asked DE to think about whether there is any additional information they could add to this chart on slide 3 to indicate how this market would respond to the severe and sudden restriction that is the concern of Enbridge in its franchise area.

AEGENT asked what the temperature scale was and Brad indicated that the "zero" point is 45 degrees Fahrenheit.

DE now proceeded to slide 5. DE used this graph to indicate that there is not a significant differential between summer and winter gas pricing in the CDA and that is another indicator that the market is not constrained.

EGD made the point that historical market pricing cannot be used to measure the potential for an unexpected event, they are only sensitive to foreseeable events, and this graph again doesn't address the concern of a sudden, unexpected and severe restriction.

Brad agreed that both slides 4 and 5 are broad generalizations and that they don't address the point of a sudden and severe supply restriction. This only provides a general idea of how markets act without getting into specifics. Brad indicated that he used these slides because they were considered by the Board when it made its decision.

Shell felt that this slide does provide some insight into the magnitude of penalties that might have to be imposed to ensure that shippers aren't incented to direct their CDA and EDA deliveries to other markets such as New York.

TransCanada indicated and Enbridge agreed that the markets used in the example all required to provide firm transport, and that the price changes are more reflective of normal pipeline constraints, rather than risks of unexpected capacity shortfalls.

Slide 6 was a slide based on a TCPL presentation and showed TCPL capacity on an Enbridge peak day ignoring any unusual line restriction scenarios.

TCPL's Ken Schubert confirmed that the left side of the slide was taken from TCPL's slide 21 and the right side was taken from TCPL's slide 23, and that both were without considering any unusual line restriction scenarios.

IGUA questioned DE by saying that neither TCPL nor Enbridge dispute that there is sufficient capacity to service the needs on a peak day under normal restrictions conditions, the issue with both TCPL and Enbridge are the concerns about unexpected restrictions.

TCPL added that even in peak day, with no unexpected line restrictions the EDA could still face shortfalls if there was severe competition for gas downstream of its area, given that the EDA was served to some extent by interruptible service.

Enbridge indicated that they had a slide coming up later that also dealt with this and the committee agreed to move on and return to this later if necessary.

DE emphasized that this indicates that deliveries have always been made into the CDA and EDA, and that while there may be hypothetical events that would compromise that, the fact is that deliveries have always been made.

Enbridge voiced its concern about referring to the line break on TCPL as hypothetical when it was based on an actual event this past September. Brad replied that deliveries were still made then. Enbridge's response was that if someone can guaranty that the September event cannot happen in winter, then all might be okay. The reality is that catastrophic restrictions can happen anytime and are perhaps even more likely to happen in winter. Enbridge noted that TCPL's scenarios were not hypothetical but events that did occur and are real risks.

Direct Energy's slide 7 focused on volatility and considered the impacts of gas fired generation facilities (GFGs), DSM initiatives and production. Brad indicated that producers are keeping up with demand and there is additional open season activity, but that because of an expected continuing growth in GFGs more transportation will likely need to be built.

Enbridge pointed out that GFGs generally establish their own contracts that are based on firm transportation arrangements, and referred to the NGEIR decision which described how Enbridge's assets were to be used in the support of the GFGs. The GFGs are not a concern in this issue of system reliability.

Enbridge also added that while average customer use is declining, total demand is not, and peak day demand and peak hourly demand are growing.

Slide 8 included quotes from Enbridge and other industry participants from a recent GFG conference along with industry responses to Enbridge.

IGUA asked DE to comment on the last quote on that slide which was "GFG gas demand forecast to grow less than the growth in installed capacity". DE believed that this meant that there is an anticipation of builds to create more capacity.

Enbridge offered a different view of the quote saying that this growth in installed capacity results from the gas supply and distribution industry needing to build to provide capacity for all users including the "peaky" GFGs. While capacity must be built to satisfy peak demand, the low load factor means that there will be unused capacity in non-peak circumstances. Unfortunately, this does not alleviate Enbridge's concern about deliveries on peak days, when GFGs would be in all probability generating to meet electricity demand on peak days which would not be an option where EGD could rely or use their pipeline capacity in an unpredicted, severe pipeline restriction.

Slide 9 made reference to quotes from natural gas producer's and natural gas industry experts to the impending changes to the North American marketplace with the emphasis on Ontario.

Slide 10 outlined some of the specific details about Alberta and the Northeast shale gas deposits and their associated production rates and costs.

Slide 11 was used to show that natural gas exports are declining and to support the hypothesis that this should alleviate some of the pressure on TCPL.

Slide 12 offered DE's view of the conclusions that can be drawn from their presentation, which included:

- Quoting the Board's decision, "…the Board is not persuaded that Enbridge operates in a significantly constrained market…and is persuaded that extra capacity is likely to be available…" and DE agrees with this.

- DE acknowledges that there is increased operational volatility due to a change in the supply & demand dynamic and has resulted in increased activity at Dawn; increased GFG (Demand Side Management), less reliance on WCSB & increased alternative gas supplies, and that this represents a challenge for Enbridge to manage.

- LDC's should "…develop services that will improve the interface between gas and electricity and in doing so will enhance: the wholesale gas market, which will benefit all gas users; and the reliability of the electricity system …"

    1. The operational volatility could support the review of EGD's current design degree day and that DE would support that review.

    2. DE supports and understands the need to replace Peaking Contracts with STFT

    3. DE indicated that they would be willing to investigate leverage off GFG projects (i.e.; YEC – the York Energy Centre) to negotiate additional capacity with TCPL; "FT from Dawn capacity may be available subject to back/haul exchange…with flow through NOL"

- DE would be prepared to negotiate the assignment of short-haul firm transport from EGD that would follow the customer, thereby mitigating attrition risk, while locking in FT.

- Security of supply can be ensured through diversification of supply basins and transportation pathways.

DE made a proposal regarding their willingness to support concerns of Enbridge by contracting for more firm transport, but doing so through FT from Dawn not Empress. This would be based upon a vertical slice approach and would require some firm transportation backhaul arrangement through TCPL and the Northern Ontario Line.

DE clarified that this doesn't mean that they would participate in an open season for shorthaul from Dawn, but that they would encourage Enbridge to do so and they would try to work with Enbridge.

CME asked Enbridge for their view on this proposal and Malini replied that they would consider this proposal and that it could represent a solution, or a part of the solution, but that it would have to be applicable to the entire retail market, not just one marketer, and that the transport would have to follow the customer. She said it could be a viable solution to providing firm transport into Enbridge's CDA.

CME asked if there would be any incremental costs that would flow down to ratepayers. Enbridge indicated that as long as the asset stranding issue was resolved there would be no costs other than those attributable to the retailer, but that they would analyze this proposal in more detail for the next meeting.

In response to a question from Enbridge, DE clarified that this would be equivalent to a "shorthaul vertical slice" and would apply only to short haul.

Morning Break

4. System Reliability Working Committee April 8, 2010 – Keith Irani & Malini Giridhar

Keith Irani began his presentation after the morning break. He first advised the committee that Shell had distributed their response to item 5 on slide 9 of Enbridge's January 21 presentation and that it would be incorporated into the Options slide.

Slides 4 and 5 were Enbridge's response to SR3.01

Slide 6 was the response to Action Item SR3.06 outlining the costs of supplying and installing shut-off and flow control equipment at Firm Customer locations. In response to a question, Enbridge indicated that these 50 large customers were probably already included in the emergency response grouping.

Enbridge indicated that this would be a rough per customer cost, whether there were one or many customers.

Slide 6 focused on the results of an informal survey Enbridge did on 19 large, non-IGUA customers as per Action Item SR 3.06. The results were:

- 10 preferred the vertical slice option
- 7 preferred the remote shut-off equipment, and
- 2 had no answer.

IGUA saw this as a significant finding in that there is clearly an interest in avoiding the firm transport option, even based on the cost of remote shut-off equipment, and the risk of being shut-off for failure to delivery.

Slide7 presented a different perspective on Capacity Outage Scenarios and potential shortfalls. The slide shows the impact on Enbridge's CDA and EDA using TransCanada's figures for the two shortfall scenarios of 600, and 1,770,000 GJs; and also a scenario selected by Enbridge to fall in between the two TransCanada scenarios at 950,000 GJs.

Using Enbridge's mid-point scenario and a 39.5DD peak day criteria, the shortfall in Enbridge's CDA would still add up to 384,000 GJs, which would equate to shutting down 384,000 residential customers in the CDA. At the same time there could be as many as 144,000 customers shut-off in the EDA.

If those numbers were applied to a peak day of 43.9 DD as was recorded in 1994, the shortfall would effectively shut down 682,000 natural gas customers in Enbridge's CDA.

The worst case scenario which was based on the 1,770,000 GJ restriction that was observed in September 2009, happening on a 43.9DD peak day, the shortfall could be as great as 1,014,000 GJs in the CDA and 198,000 GJs in the EDA, causing shut-off of gas supply to over 1 million residential customers in the CDA and 200,000 customers in the EDA.

In response to a question from AEGENT, Enbridge agreed if they could gain confidence in curtailment and if peaking was secured by firm transport, the shortfall would be reduced by approximately 300,000 GJs.

TransCanada reminded everyone that if Enbridge firmed up an additional 300,000 GJs, it would reduce TransCanada's available capacity by an equivalent amount which would greatly increase the risk associated with getting supply for the remaining exposed volume; thus emphasizing the need to firm up more than just the 300,000 GJs.

IGUA asked that the chart on Slide 8 be restated on the assumption that there was complete confidence in curtailment, and peaking was underpinned with firm supply. Enbridge agreed to do that. The purpose of the exercise was to attempt to quantify the amount of supply that would still need to be firmed up to avoid the 716,000 GJ shortfall.

Direct Energy suggested that under this scenario, even if all direct shippers were entirely firmed up there would still be a significant shortfall. Enbridge agreed but acknowledged that that shouldn't diminish the need to firm up the portions that can be firmed up.

AEGENT followed-up by asking Enbridge what they would have done in the scenario just described by DE, and Enbridge they would have to approach TCPL to ask if additional volumes were available, but assuming there weren't, Enbridge would have to shed load (shut down additional customers).

AEGENT went on to confirm with Enbridge that the concept of a line break was never included in Enbridge's original analysis of the Design Day Criteria. Enbridge agreed and said that a line break situation would affect all shippers on an equal prorata basis if all shippers are firm (as they were in the 90s). However in today's situation where more than the half the volumes to the CDA are non firm, while other jurisdictions like Union and GMi were mostly firm, the impact of a line break would be felt disproportionately by EGD's franchise area. Given the predominantly residential load and the size of EGD's franchise, this could cause a very significant outage for EGD customers. Other utilities, as was the case with GMi, have had a reserve margin built in. Such a margin could be used to deal with higher than design degree days, higher than average wind or supply failure whatever the cause.

Shell asked Union if they were accepting turnbacks in Union North and Union said they are. EGD clarified that it was their understanding that Union North allows large volume customers to turnback capacity but that mass marker customer arrangements are Western T without turnback.

Enbridge was asked if there were any curtailment options with the GFG customers. Enbridge indicated that there is currently no opportunity to do that and it would require involvement of the IESO, Ministry of Energy and the OEB and a policy consideration about gas supply being more important than the potential of electricity brown-outs. Enbridge added that intuitively, it is hard to imagine that policy makers would see sense in shutting down needed electrical generation to account for natural gas users not wanting to firm up their supply arrangements. IGUA felt that if the economics showed that it was less expensive to shut-down generation than it is to firm up gas supply policy makers might agree.

Following further discussion among IGUA, AEGENT and Enbridge it was agreed that there could be times when the GFG didn't need their capacity and by some agreement could release it to Enbridge to supplement their supply. Enbridge said that it has been talked about and is an item of consideration, but in order for that to be considered as a firm source there would have to be some form on call option that would give Enbridge priority access to the gas, regardless of the need for electricity. That would probably be problematic. TCPL added another issue that the contract to a GFG is to their specific location, and that might not permit it to be diverted to any other location.

The table on Slide 8 was filled in based on the Assumptions shown on Slide 9 and it shows the relative impacts on rate classes 1, 6 and large volume, for four options.

The following points of clarification were offered in response to committee members questions about the Estimated Customer Impact table on slide 8:

- The vertical slice option assumed that the 200,000GJ/day was contracted on TransCanada;
- The costs of the vertical slice were spread among all customers;
- The costs of the backstopping were allocated to only Ontario T customers;
- The entire table is based on current TCPL tolls;
- The backstopping would not be assigned; it would just be available if required.
- The option offered by Direct Energy earlier in the meeting, would be slightly different, in that transport would be assigned to the use of the direct shipper to deliver their MDV;
- In Enbridge's Backstopping option, If the direct shippers delivery did not show up, Enbridge would buy the quantity through the backstopping arrangement and charge the direct shipper for the transportation costs;
- The nomination of the quantity would probably have to be a short notice backstopping service which could add 20% to the transport charges, and that surcharge has not been included in this analysis;
- With the vertical slice option the direct purchase community would be assigned the shorthaul from Dawn, along with a slice of the other supply sources;

- The shorthaul Dawn to CDA and EDA is assignable, as opposed to the M12 and STS,;
- The DD option would be allocated primarily to heat load customers, rates 1 and 6.
- The costs in the peaking option represent the difference between the STFT and the current peaking service;
- The cost allocation is based on multiple uses of the extra STFT in order to minimize its cost impacts.

AEGENT indicated that while they would have no problem with Enbridge applying for a change to the degree day design methodology, it seems to be independent of the system reliability issue. Enbridge agreed that the adequacy of degree day methodology could be viewed separately from the contracting issue, but indicated that the change to a more conservative methodology, like the ones used by Union south and GMi, would reduce the amount of exposed volume that would need to be addressed in this system reliability issue.

IGUA asked Enbridge if they could redo the Peaking option on slide 8 using the assumption that it was not employed for multiple uses, but instead was dedicated to the use for peaking. Enbridge agreed to do that.

Slide 10 described some changes being considered to firm up the effectiveness of the curtailment program; Ian Macpherson led the committee through the slide.

Based on experience Enbridge only includes 60% of the contracted interruptible volume in its planning as emergency supply. Malini clarified that the adjustment is made to reflect that all interruptible customers may not be using their contract demand on peak day, thus reducing the amount of demand response. In addition, Enbridge has found that many customers that have taken the interruptible option are not really in a position to interrupt their supply, such as apartment buildings.

Ian summed up by saying that Enbridge is paying out credits to interruptible customers to be able to use their volume for system reliability when needed. Clearly if the volume is not available then it becomes a question of value for money. The credits to interruptibles mount up to about $10 million.

Enbridge stated that any new charges or arrangements with interruptible customers would have to be incorporated in the rate handbook, and would be best done in consultation with IGUA and Enbridge's large use customers.

Without these changes, there would have to be adjustments to the volume included in Enbridge's supply portfolio for the curtailment option.

DE asked why penalties are considered as a viable deterrent in this case and not in the case of direct purchase customers. Malini explained that the economic comparisons in the two cases are different. Penalties were more effective when direct purchase customers held firm transport and the penalty was designed to prevent diversion of the gas to another area. With shippers not holding firm transport the penalties would have to exceed the cost of holding firm transport for the entire year; in which case, the preferred solution is to require firm transport. Interruptibles would weigh the penalties against arranging for alternate fuels and losing their interruptible credits, Enbridge believes that the penalties applied to interruptibles would be more effective given the monetary benefits they stand to lose.

The last two slides, 11 and 12 showed the System Reliability Matrix that has not been completed by the majority of the committee members. Enbridge indicated that they are trying to get intervenors comments on the impacts to their clients and that Enbridge needs this to finalize their position.

Enbridge once again made a plea to get parties' positions, preferences or general comments on the options that are included on the System Reliability Matrix included on slides 11 and 12, April 8, 2010. To date only CCC/VECC and DE have replied. Members agreed that comments would be in by the end of the day on April 15, 2010, on the understanding that if they do not reply by then, that Enbridge can assume that there were no comments. All members agreed.

In response to one final question from VECC, Enbridge indicated that there is no significant capital costs associated with implementation of either the Degree Day methodology changes or the peaking option.

The meeting adjourned at 1:00 PM and parties agreed to reconvene at 1:30 PM to begin the Mass Market Unbundling Working Committee meeting.

Adjourn

Note to Readers:

Action items arising from this meeting can be found in Appendix D.

Appendices

Appendix A: Meeting Agenda April 8, 2010

COMMITTEE MEETING

STAKEHOLDER CONFERENCE
Thursday, April 8, 2010
9:00 AM – 12:00 PM
Ontario Energy Board
2300 Yonge St., 25th Floor
West Hearing Room
System Reliability

AGENDA 9:00 - 9:10 am	**Opening Remarks -** Bob Betts, Facilitator • Welcome and Housekeeping Items • Objectives and plan for this meeting • Next steps
9:10 – 12:00 am	**EGD System Reliability Presentation -** M. Giridhar/K. Irani • Action Items from February 25, 2010 System Reliability Meeting • Shell Energy Option 5 - Firm Delivery table • Capacity outage scenarios • Rate Class Impact of Options considered • System Reliability matrix

LUNCH

Appendix B: Participant Listing

Stakeholders

Attendee	Organization
Frank Brennan	AEGENT
Vince DeRose	CME
Ric Forster	Direct Energy
Brad Janzen	Direct Energy
Ian Mondrow	IGUA
Rob Rowe	IGUA
Colin Schuch	Ontario Energy Board
Paul Dumaresq	Shell Energy
Murray Ross	TCPL
Lisa DeAbreu	TCPL
Zafir Samoylove	TCPL
Ken Schubert	TCPL
Jim Bartlett	TCPL
Chris Ripley	Union Gas
Don Newbury	Union Gas
Roger Higgin	VECC & CCC

Enbridge Representatives

Attendee	Position
Malini Giridhar	Director, Energy Supply & Policy
Keith Irani	Manager, Energy Supply Services
Hilmi Muhammad	Manager, Energy Forecasting and Planning
Robert Bourke	Manager, Regulatory Proceedings
Ian Macpherson	Manager, Direct Purchase
Kent Wirth	Manager, Gas Control & Nominations
Edith Chin	Manager Upstream Regulatory Strategy &Major Projects

Other

Bob Betts	Facilitator, Regulatory Support Services

Appendix C: EGD System Reliability Working Committee Presentation by Keith Irani / M. Giridhar

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System Reliability Working Committee

April 8, 2010

System Reliability Working Committee Opening Remarks – Bob Betts, Facilitator

- Welcome & Housekeeping Items

- Objectives and Plan for the Meeting
  - Review from previous meetings
  - Update to Action Items
  - Presentation and discussion of costing of options
    - Gather additional committee input and finalize

- April 22 – EGD proposal and discussion

EGD System Reliability Presentation

K. Irani/M. Giridhar

Action items: Percentage of Firm Volumes to the CDA

1. ***SR3.01:*** Direct Energy asked Enbridge if they could determine what percentage of volume to the CDA was firm. He defined firm in this context as Ontario T Service where direct shippers would not have turned back their capacity.

Contract Year Ontario T Service (OTS) Deliveries (GJ/d) to CDA (*)		
Firm Capacity	**2008**	**2009**
FT Assigned	15,993	14,518
FT ABC Non – ABC	35,630	34,480
STFT OTS - ABC	0	40,352
Total Firm	51,623	89,350
Total OTS Deliveries	434,467	390,145
Firm Cap/Total Deliveries	12%	23%

*based on 2008 and 2009 contract year, TCPL Index of Customers as at Nov 1
**OEB interim resolution results

Turnback available in 2010 - 100%

Estimated Costs of Curtailment of Firm Customers: Hardware, Construction, Maintenance & Monitoring

2. ***SR 3.06:*** Enbridge agreed to confirm the estimated additional costs of flow-control equipment versus shut-off equipment

Nominal Pipe Size (NPS)	Actuator ($)	Construction ($)	Telemetry ($)	Communicator Controls ($)	Total hardware & Installation ($)	Customers (#)	Total Costs ($)	SCADA ($)	Total with shut off valve ($)	Total with flow control valve ($)*
NPS 2	7,300	5,000	20,000	1,000	33,300	50	1,665,000	240,000	1,905,000	**2,905,000**
NPS 3	8,000	5,000	20,000	1,000	34,000	50	1,700,000	240,000	1,940,000	**2,940,000**
NPS 4	8,600	5,000	20,000	1,000	34,600	50	1,730,000	240,000	1,970,000	**2,970,000**
NPS 6	18,000	5,000	20,000	1,000	44,000	50	2,200,000	240,000	2,440,000	**3,440,000**
NPS 8	18,000	5,000	20,000	1,000	44,000	50	2,200,000	240,000	2,440,000	**3,440,000**

Note: Costs vary by regions.

SCADA IT, maintenance and monitoring are $240,000 yearly ongoing cost.

**** Flow control valve costs initial costs are estimated at an incremental $20,000 per customer***

Action items: Survey other large users that may not be part of IGUA's membership.

3. ***SR 3.06:*** Enbridge also agrees to survey other large users that may not be part of IGUA's membership.

From a listing of EGD's top 50 customers, 19 (non-IGUA) customers were surveyed with the following question:

Given the choice between the two options as described below which would be your preference:

a. EGD arranging for all upstream transportation capacity and assigning customers a vertical slice of the Company's transportation portfolio

or

b. Installation of a remote shut off valve at the customer's facility that could be activated should a customer fail to supply their MDV delivery of gas. Cost of shut off valve to be borne by customer. (approx costs provided)

<u>Results</u>

▪ Remote Shut Off	7
▪ Vertical Slice	10
▪ Refused to answer	2

Capacity Outage Scenarios & Resulting Shortfall in EGD CDA and EDA (GJ)

Residential Customer Peak Day Volumes ≈ 1 GJ			
System Outage Scenario	**Jan 2009** **600,000**	**EGD Hypothetical** **950,000**	**Sep 2009** **1,770,000**
Current Peak Day Criteria: 39.5 DD			
CDA			
Non Firm/Exposed Quantity	716,000	716,000	716,000
Potential shortfall	34,000	384,000	716,000
EDA			
Non Firm/Exposed Quantity	144,000	144,000	144,000
Potential shortfall	up to 144,000	up to 144,000	144,000
Historical Peak Day Criteria: 43.9 DD			
CDA			
Non Firm/Exposed Quantity	1,014,000	1,014,000	1,014,000
Potential shortfall	332,000	682,000	1,014,000
EDA			
Non Firm/Exposed Quantity	198,000	198,000	198,000
Potential shortfall	up to 198,000	up to 198,000	198,000

Notes: Capacity reduction based on TCPL's Feb 25, 2010 presentation
Analysis does not reflect higher than average wind speed on peak day. Sources of shortfall include direct purchase deliveries, peaking supplies and curtailment of interruptible customers

Estimated Customer Impacts

		Rate 1		Rate 6	Large Volume
Option	**Incremental Firm Capacity (GJ/d)**	**Impact** *(¢/m³)*	**Annual $**	**Impact** *((¢/m³)*	**Impact** *(¢/m³)*
Vertical Slice (Transport)	200,000	0.2	$7	0.2	0.2
Backstopping (Provided to Ontario T only)	200,000	0.4	$13	0.4	0.4
Design Day (Load Balancing)	350,000	0.6	$19	0.5	0.1
Replacement of Peaking with STFT	250,000	Sales & Western T 0.2 Others 0.3	Sales & Western T $6 Others $9	Sales & Western T 0.2 Others 0.3	Sales & Western T 0.2 Others 0.3

Note: EGD does not determine the transportation charge for Ontario T customers

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Assumptions for Options in Estimated Customer Impacts

- Vertical slice: EGD contracts 200,000 GJ/d LH FT on behalf of all mass market customers. System (IT) changes to implement Vertical Slice is estimated at $5 million.

- Backstopping: EGD contracts for 200,000 GJ/d SH FT on behalf of direct purchase customers.

- Design day: Assumes STFT for 3 months (Jan –Mar) to meet incremental capacity requirements for change in degree day. Costs allocated on peak allocator

- Replacement of Peaking: EGD contracts incremental STFT for 3 months (Jan–Mar) to meet peak design day demand. STFT costs allocated on annual deliveries, with a partial offset in the transportation charge for reduced Dawn purchases.

Curtailment Program Effectiveness

Proposed Changes to Interruptible Distribution Service Rates (145, 170)

- demonstrate alternate fuel supply or ability to "accommodate total interruption of gas service"
- Curtailment Credit
  - paid on *"average winter use"* vs. MDV
  - Monthly Curtailment Credit not paid for customers who fail to comply with an order to curtail
  - Re-evaluate market value of interruptible services (current $10 million annually)
- Unauthorized Overrun Gas Rate: revised to 150% of the highest price of gas in effect on the day
- Eliminate Rate 145-72
  - Limited operational benefit (one time in 5 years)

System Reliability Matrix

Impact of Options	System Reliability			Competitiveness	Ratepayer/ Stakeholder impacts	Term
Options	**Firm Transport**	**Incremental Supply (backstopping)**	**Load Reduction (curtailment of firm customers)**	**Impact on Competitive Market**	**Ratepayer & Stakeholder Impacts**	**Estimated Lead time**
1. Vertical slice	• firm contracts to delivery area	• not required	• not required		TBD (CCC/VECC)	2-3 yrs
2. **Interim**						
a. Board interim resolution	• firm transport to delivery area (Jan-Mar), increasing 10% each yr	• potential option	• potential option		Cost $xxx (CCC/VECC)	3-6 mths
b. EGD interim solution (modified)	• firm transport (% of MDV) to delivery area (Dec-Mar)	• potential option	• potential option		Cost to be Determined (CCC/VECC)	3-6 mths
c. Direct Energy	• firm transport to delivery area, frozen at 2010 levels	• potential option	• potential option		Cost to be Determined (CCC/VECC)	3-6 mths

System Reliability Matrix

Impact of Options	System Reliability			Competitiveness	Ratepayer/ Stakeholder impacts	Term
Options	**Firm Transport**	**Incremental Supply (backstopping)**	**Load Reduction (curtailment of firm customers)**	**Impact on Competitive Market**	**Ratepayer & Stakeholder Impacts**	**Estimated Lead time**
3. Backstopping service	• potential option	• required	• potential option		Cost? (CCC/VECC)	1 year
4. Curtailment of firm customers	• not required	• not required	• required		Not Viable Option (CCC/VECC)	1-2 years
5. Firm Delivery/Financial rating	?	?	• potential option		More Info (CCC/VECC)	3-6 mths
6. EGD Design Day	• option to contract for incremental transport in winter	• potential option	• not required			
7. EGD Peaking contracts	• option to contract for incremental transport in winter	• potential option	• not required			

Appendix D: Summary of Action Items

From the System Reliability Committee Meeting 4
Held on April 8, 2010

Item	Page	Task	Responsibility
SR4.01	1	Ian Mondrow asked if Enbridge could forward him the copy of the original letter of August 31, 2009 and all of the attachments that went to the Board defining the consultation process. He indicated that he was missing Attachment 4.	Enbridge,
SR4.02	3	Dwayne Quinn asked for two things in closing: • That Enbridge provide a description of how this process will move forward, thereby helping him understand how he will be able to participate in the settlement process; and • That he be added to the distribution list for any and all materials related to the process.	Enbridge
SR4.03	3	IGUA asked Enbridge if it could analyze and comment on the information provided on Slide 3 of DE's presentation. Enbridge said it could, but that it would need to know the details of the numbers, including what they are based on and what they mean.	Enbridge
SR4.04	4	IGUA was not surprised by Enbridge's position and asked DE to think about whether there is any additional information they could add to this chart on slide 3 to indicate how this market would respond to the severe and sudden restriction that is the concern of Enbridge in its franchise area.	Enbridge
SR4.05	7	CME asked if there would be any incremental costs that would flow down to ratepayers. Enbridge indicated that as long as the asset stranding issue was resolved there would be no costs other than those attributable to the retailer, but that they would analyze this proposal in more detail for the next meeting.	Enbridge
SR4.06	8	IGUA asked that the chart on Slide 8 be restated on the assumption that there was complete confidence in curtailment, and peaking was underpinned with firm supply. Enbridge agreed to do that. The purpose of the exercise was to attempt to quantify the amount of supply that would still need to be firmed up to avoid the 716,000 GJ shortfall.	Enbridge
SR4.07	10	IGUA asked Enbridge if they could redo the Peaking option on slide 8 using the assumption that it was not employed for multiple uses, but instead was dedicated to the use for peaking. Enbridge agreed to do that.	Enbridge
SR4.08	11	Enbridge once again made a plea to get parties' positions, preferences or general comments on the options that are included on the System Reliability Matrix included on slides 11 and 12, April 8, 2010. To date only CCC/VECC and DE have replied. Members agreed that comments would be in by the end of the day on April 15, 2010, on the understanding that if they do not reply by then, that Enbridge can assume that there were no comments. All members agreed.	All Committee Members

Appendix E: 3. April 8, 2010 Direct Energy – Brad Janzen & Jamie Humble

Enbridge System Reliability

April 8, 2010

Direct Energy – Brad Janzen & Jamie Humble

Agenda

1. What has been established?

2. The Enbridge problem: Operational volatility.

3. Helping Enbridge help themselves; the role of marketers & producers.

“…system reliability is of the utmost importance.”

- “…the Board considered **the excess capacity currently available on TCPL’s pipeline** and is persuaded that extra capacity is likely to be available in the coming winter to support any additional firm transport required by the direct shippers.” - OEB Decision & Order Phase 2 July 14, 2009 pg 10

- “…the evidence suggests that **there is excess capacity on the TCPL mainline** which gives the Board confidence that peak day demands can be met with the interim solution in place.” – OEB Decision & Order Phase 2 July 14, 2009 pg 11

- “…Enbridge has focused on only one three-day period…(January 13-15, 2009) to highlight its concerns regarding system reliability. Yet even during this **period…interruptible customers, who had been fully curtailed, were able to bring in approximately 440,000 GJ of Curtailment Delivered Supply over the three days**.” The Final Submission of the OAPPA, June 2, 2009 pg 3 – OEB Transcript Volume2, May 8, 2009 pg’s 11-12

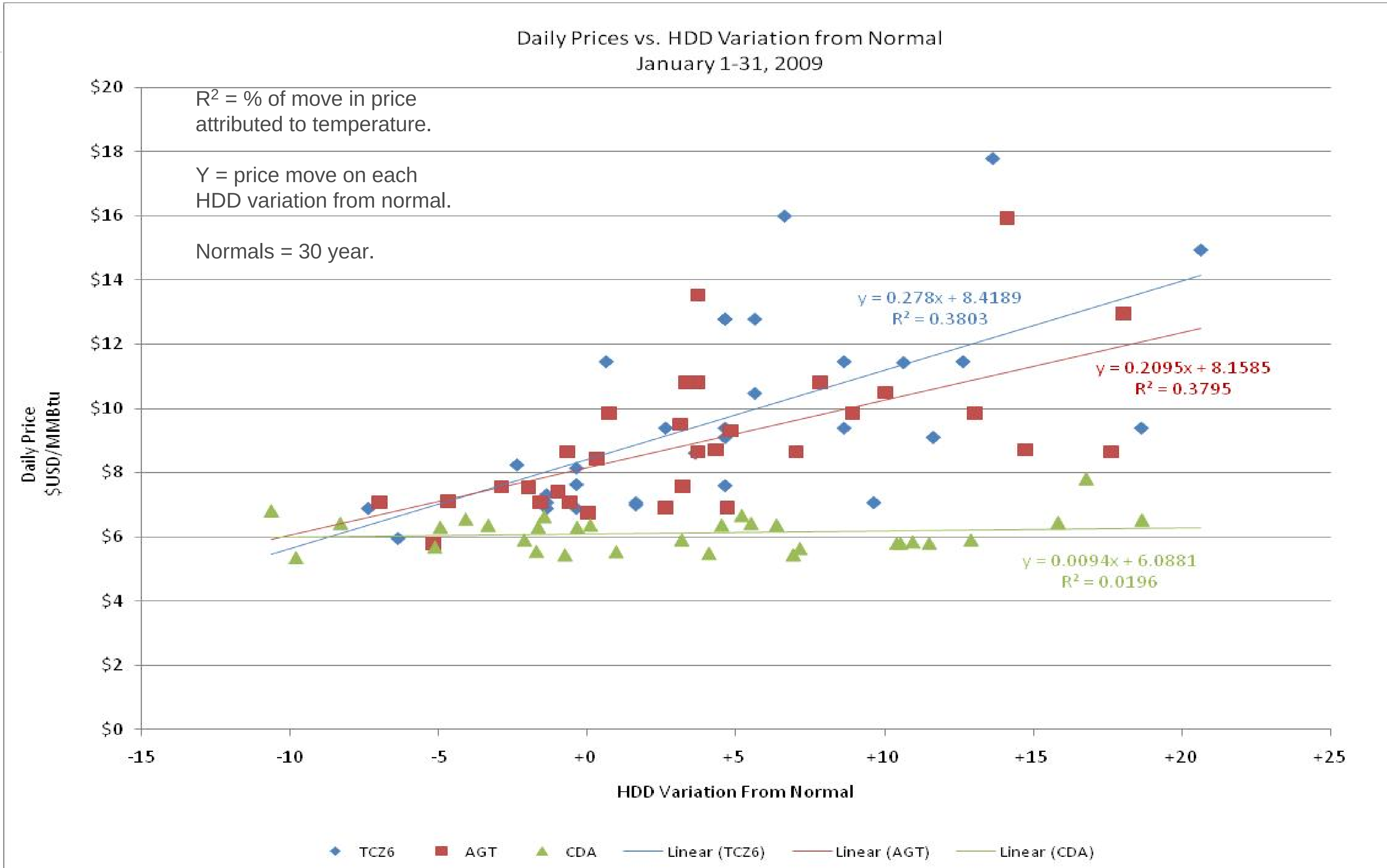
- **“TransCanada agrees that the Enbridge request for direct shippers to hold FT does not create any additional operational capacity.”** TCPL Interrogatory Responses April 20, 2009

- **“…daily load balancing is the LDC’s responsibility to ensure everybody gets gas on coldest days of winter**. In Enbridge’s case, the LDC must have sufficient contractual rights between pipeline capacity, storage withdrawal capability and other peaking services to meet its forecasted peak day.” EB-2008-0106 5-15-09

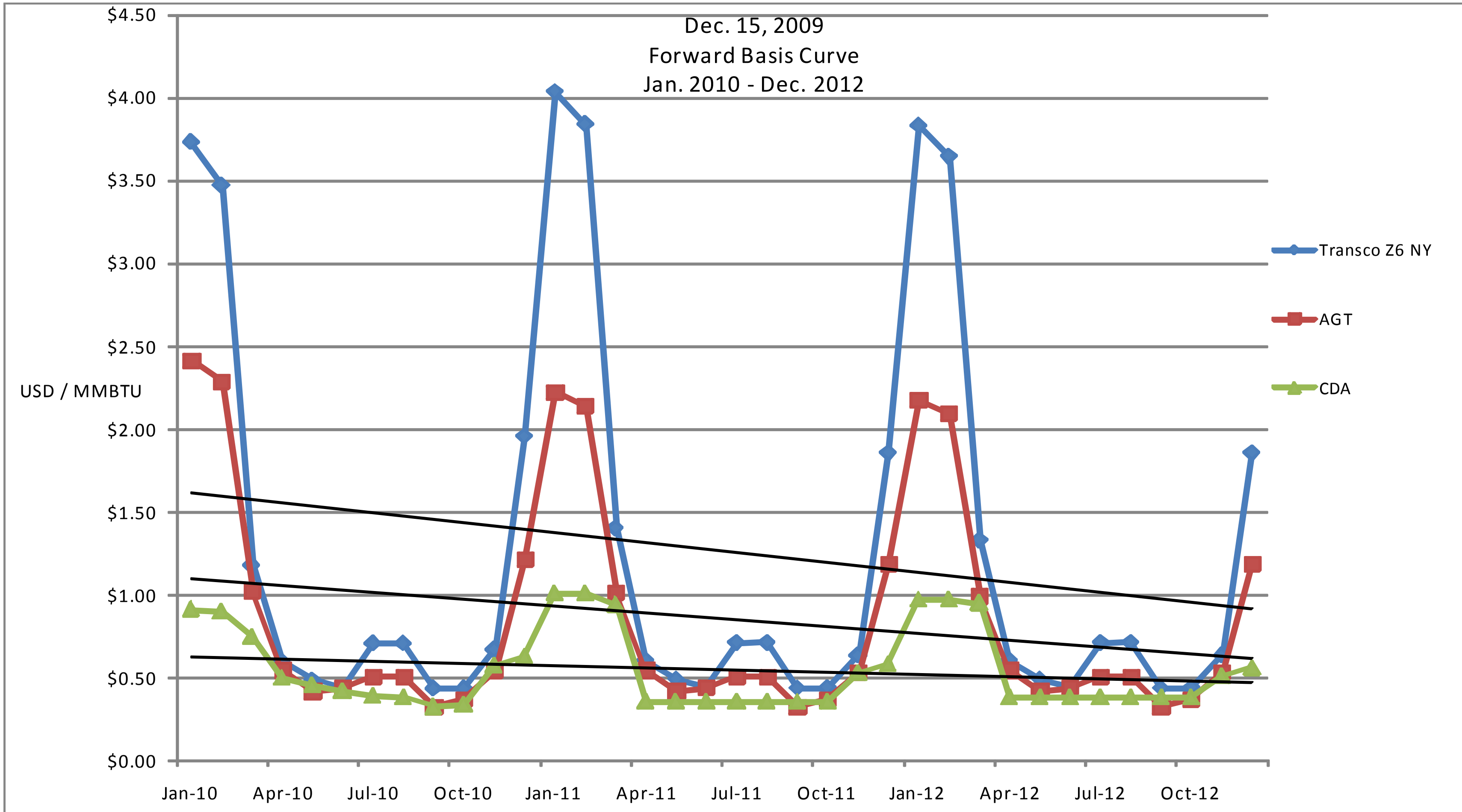
- Emergency Plan; Phase 0 = 180,000 gj’s / Phase 1 = 200,000 gj’s / Phase 2 = 100,000 gj’s; addresses “…a shortfall of 300,000 gj’s without…having to do anything…to the supply of residential customers…” OEB Hearing May 8, 2009 Volume 2 pg’s 16-17

- “The Board directs Enbridge to file an application which puts forward various options…including that of allocating a “Vertical Slice” of Enbridge’s transportation.”

"…the Board is not persuaded that Enbridge operates in a significantly constrained market…" - OEB Decision & Order Phase 2 July 14, 2009 (pg 11)

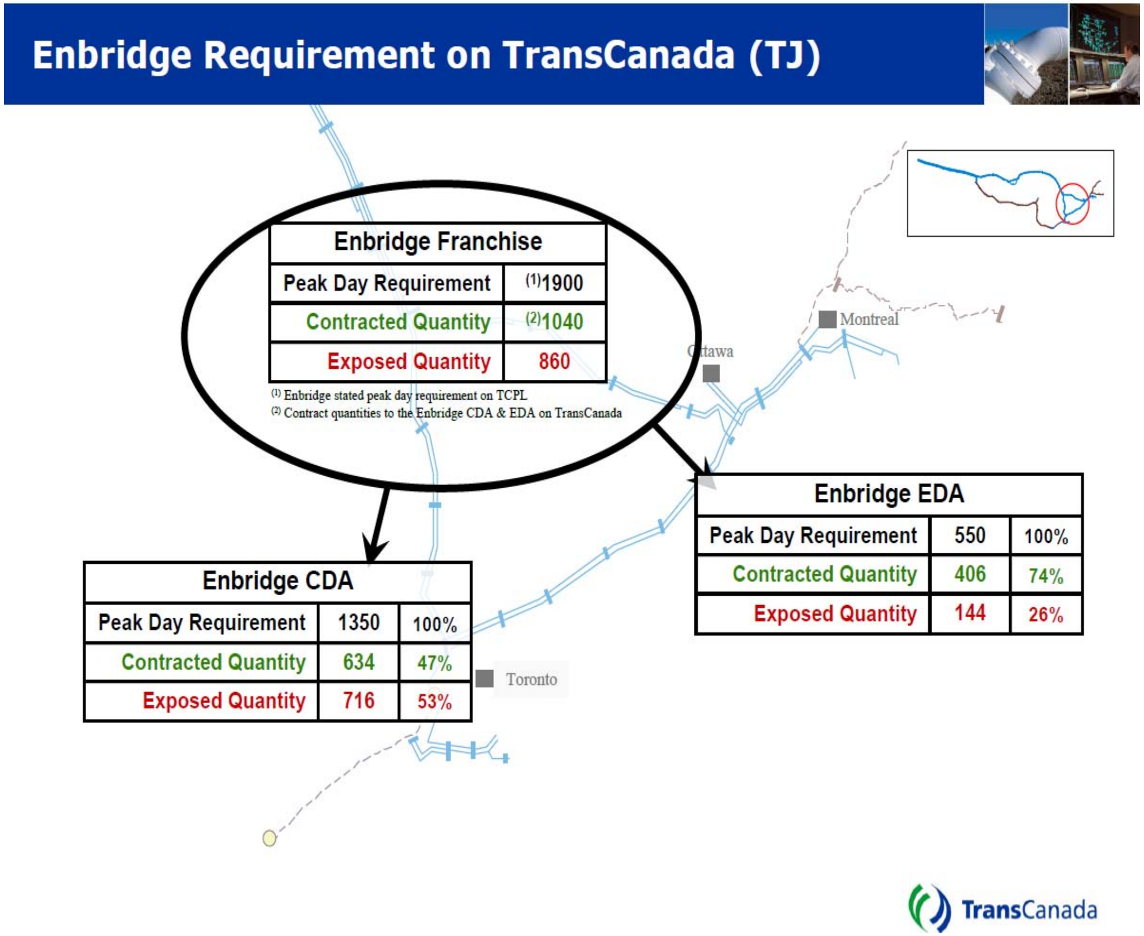


"…the difference between winter and summer forward pricing does not reveal the substantial difference that marks a constrained market…" - OEB Decision & Order Phase 2 July 14, 2009 (pg 11)



"…the Board considered the excess capacity currently available on TCPL's pipeline and is persuaded that extra capacity is likely to be available in the coming winter…"
OEB Decision & Order Phase 2

Enbridge Requirement on TransCanada (TJ)



Enbridge Franchise	
Peak Day Requirement	(1)1900
Contracted Quantity	(2)1040
Exposed Quantity	860

(1) Enbridge stated peak day requirement on TCPL
(2) Contract quantities to the Enbridge CDA & EDA on TransCanada

Enbridge CDA		
Peak Day Requirement	1350	100%
Contracted Quantity	634	47%
Exposed Quantity	716	53%

Enbridge EDA		
Peak Day Requirement	550	100%
Contracted Quantity	406	74%
Exposed Quantity	144	26%

TCPL capacity & EGD Peak Day

Enbridge Franchise		
Exposed Quantity	860	860
Northern Ontario Line		
Available - All / Firm	2205	1879
Excess Capacity	1345	1019

What if EDA & exports peak?

Enbridge Franchise		
Exposed Quantity	716	716
Northern Ontario Line		
	All	Firm
Available	2205	1879
Less EDA	(923)	(923)
Available to CDA	1282	956
Excess Capacity	566	240

The Enbridge problem; Operational volatility

Enbridge, GMI and Union seeing flat to declining annual demand growth but increasing peak days, why?

- About 10% of the natural gas consumed in Ontario (1,000 Bcf/yr) is used to generate electricity.

- Under the IPSP, natural-gas fired generation capacity in Ontario grows by 140% from 5,029MW in '07 to 12,082MW in 2015 – Natural Gas-Fired Generation in the Integrated Power System Plan, North Side Energy, LLC May 2008

- "Gas-fired generators that enter into contracts with the OPA are expected to acquire natural gas at the Dawn Hub. **Buying at Dawn reduces exposure to firm transportation charges,** provides access to natural gas storage and balancing services…" Natural Gas-Fired Generation in the Integrated Power System Plan – prepared for the OPA by North Side Energy, LLC May 2008

  Demand Side Management, related to the development of gas-fired generation, is driving a shift from long-haul transport to short haul transport out of Dawn and increasing operational volatility.

  Excerpt's from **"Gas-fired Generation and Influence on Demand, Storage and Pipeline Operations"**
  Enbridge 1/22/08 Malini Giridhar

- GFG sector is driving growth... Demand forecast to grow by up to 0.2 Bcf/d from 2008.

- **Peak Day flows expected to be higher. Changing gas flows and market unbundling create stress on upstream services and assets used by LDC for daily balancing of loads.**

- Changes on LDC's balancing role:
  - Shift in long haul transportation contracting practices
  - Increase short haul services (TCPL LH Toll **$1.64** vs. EGD system charge **$1.25**).
  - Increase storage transportation

- "Maintain the ability to use natural gas capacity at peak times and pursue high efficiency and high value use of fuel" Ontario Government Supply Mix Directive for Electricity. (Peak times – 14% of the hours with the highest demand)

An Enbridge Response – GFG 1/22/08

- Increase transport infrastructure
- Increase pipeline and balancing services with greater flexibility
- Ensure regulatory climate encourages adequate infrastructure growth
- Establish clear communication protocols between gas industry players, generators and the IESO
- Preserve liquid & competitive markets and services
- Recognize LDC's role in ensuring cost effective balancing of end use customer

An Industry Response

- LDCs should "…develop services that will improve the interface between gas and electricity and in doing so will enhance: the wholesale gas market, **which will benefit all gas users; and the reliability of the electricity system,** which will benefit all electricity users." - APPrO

- "**Union wants to attract as many customers as possible to the Dawn Hub**…" - Union Gas - Asset Expansion & Longer Term Initiatives September 14, 2009

- The Dawn Hub provides Power Generators services for short notice start-up/shut-down, access to balancing and storage services and access to multiple supply basins.

- Shift from Long-haul transport to Short-haul transport out of Dawn.- Asset Expansions & Longer Term Initiatives, Uniongas

- GFG gas demand forecast to grow less than growth in installed capacity

A Producer Response

- "The Northern Access project will enable Marcellus…gas to flow to…liquid markets at Niagara and Dawn." - National Fuel OS159

- U.S. gas producers eye Ontario market – Report on Business Feb. 24, 2010
  - TCPL & Union "…have issued "open season" calls to determine the interest of Marcellus producers in supplying gas to the Ontario market from Pennsylvania and West Virginia…westward to its Dawn hub near Sarnia."
  - "…eastern consumers are also seeing new supply from Canaport liquified natural gas terminal…"
  - "…loss of market share in Ontario could undermine the economics of shipping western gas to eastern markets. **Declining volumes would drive up pipeline tolls**…" Richard Zarzeczny, President Canadian Enerdata Ltd.

- 10% of Canadian natural gas exports are being displaced by REX gas. - Resource Investor, 7/8/2009

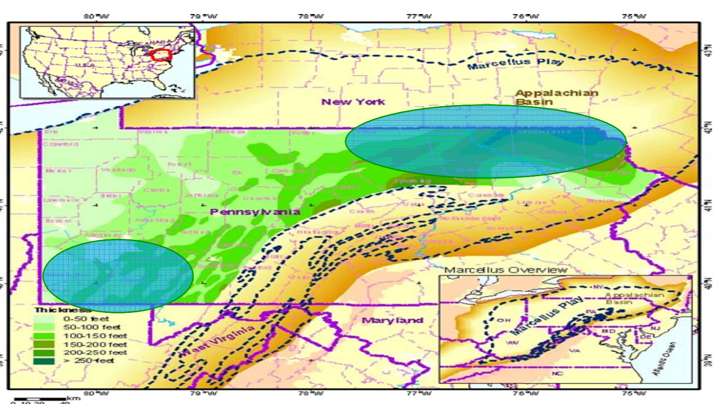
- **Dawn Gateway** - Adds new Rockies and Mid-continent supplies to Dawn
  - Connects new and existing storage to Dawn Hub
  - Initial capacity of 360,000 Dth/d starting November 2010

The best way to ensure security of supply is through diversification of supply basins and transportation pathways. Marcellus Shale is well positioned to be a key supply basin for Ontario.

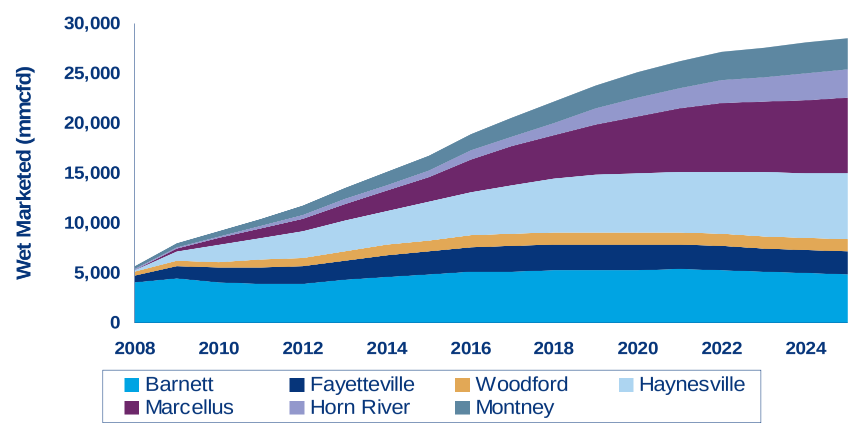
Production costs in the Marcellus Shale are dropping quickly as technologies and well optimization strategies are improved.

- 2007: average initial test rate 2.4 mmcf/d and average completion costs $3.1M
- 2008: average initial test rate 3.6 mmcf/d and average completion costs $2.6M
- 2009: average initial test rate 5.1 mmcf/d and average completion costs $2.1M

Source: Range Resources.

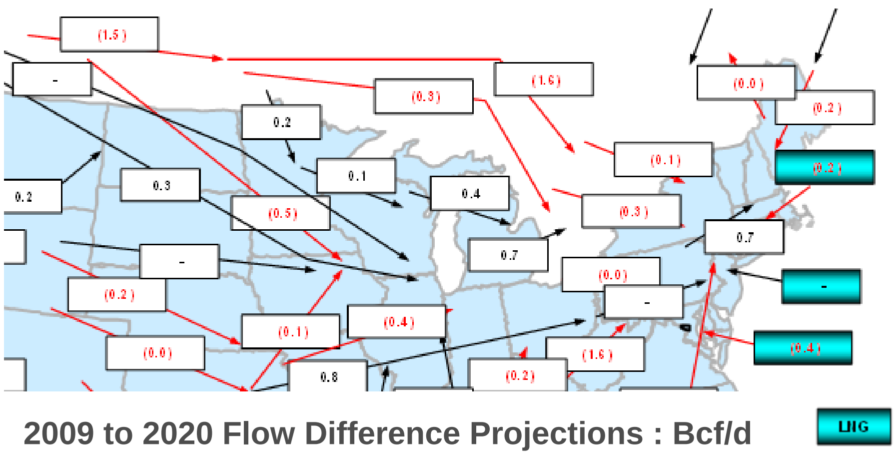


Marcellus Gas deposit locations.



Shale Gas production set to grow steeply
Source: Wood Mackenzie

There is a shift underway on how natural gas will be sourced in Eastern North America.



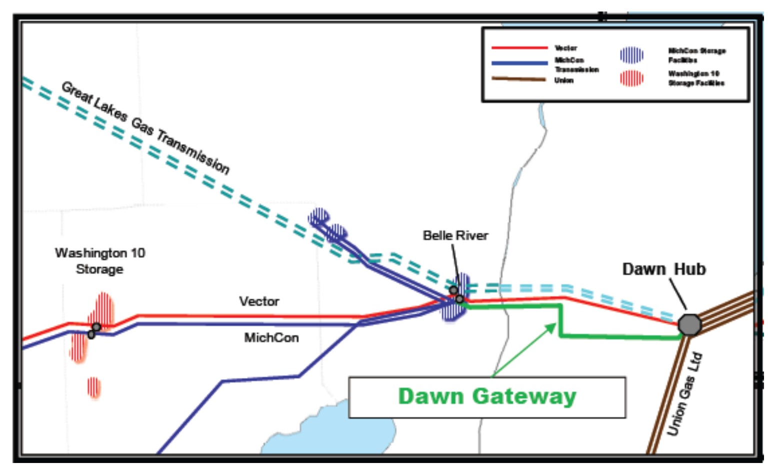
2009 to 2020 Flow Difference Projections : Bcf/d
Source: Wood Mackenzie

As alternate supply basins and pathways begin supplying the Northeast, there will be a reduced reliance on WCSB and TCPL longhaul (and associated Canadian exports out of Ontario) leaving Enbridge franchise area even less constrained.

Dawn Gateway project is a good example of how Ontario is becoming less reliant on Western Canadian deliveries.

- Partnership between DTE Pipeline Company and Spectra Energy
- Connects MichCon's Belle River to Union's Dawn Hub
- In service November 1, 2010
- Initial capacity of 360,000 Dth/d
- Readily expanded with compression

Source: DTE Energy



Conclusions

- "…the Board **is not** persuaded that Enbridge operates in a significantly constrained market…**and is** persuaded that extra capacity is likely to be available…"

- Increased operational volatility is due to a change in the supply & demand dynamic and has resulted in increased activity at Dawn; increased GFG (Demand Side Management), less reliance on WCSB & increased alternative gas supplies.

- LDC's should "…develop services that will improve the interface between gas and electricity and in doing so will enhance: the wholesale gas market, which will benefit all gas users; and the reliability of the electricity system …"

  1. The operational volatility could support the review of EGD's current design degree day.

  2. Replace Peaking Contracts with STFT

  3. Leverage off GFG projects (ie; YEP) to negotiate additional capacity with TCPL; "FT from Dawn capacity may be available subject to back/haul exchange…with flow through NOL"

  DE would be prepared to negotiate the assignment of short-haul firm transport from EGD thereby mitigating its attrition risk while locking in FT.

- **Security of supply can be ensured through diversification of supply basins and transportation pathways.** "The gold medal winners will be the ones who…bring the gas to market most efficiently at the lowest cost" **to the benefit of all rate-payers.**

Working Committee Notes

(With the Revised Presentations)

Enbridge Gas Distribution Inc. Working Committee Meeting 5 On System Reliability

April 30, 2010
Ontario Energy Board
2300 Yonge St., 25th Floor
West Hearing Room

Prepared By:
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Putting the Pieces Together

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Enbridge Gas Distribution Inc.
Working Committee Meeting 5
On
System Reliability

1. Opening and Introductory Remarks

Presented by Bob Betts, Facilitator

The meeting was called to order at 9:15 a.m. Bob Betts welcomed all those in attendance and asked all participants to introduce themselves.

Bob first acknowledged that committee agreed to only do System Reliability this day and leave mass market unbundling to another date.

He reviewed the activities that occurred since the last meeting and also outlined the items on the agenda for today, which included: a review of previous action items; and the presentation of Enbridge's proposal for the resolution of the system reliability issue.

In his role as Facilitator, Bob congratulated the committee for all the time and effort that they have put into this issue, and the open and cooperative styles that they have applied to the discussions. Everyone has learned a great deal and has become much more aware of the other party's concerns and issues.

He commented that the committee is now entering the negotiating or settlement stage of this consultation and needs to continue to keep their minds open and to continue to show a willingness to accommodate the needs of others.

He reminded everyone of the benefits of a consensus or a settlement, and the risks of forcing the Board to decide, which inevitably leaves some as winners and some as losers.

Before turning things over to Enbridge for their presentation, Bob pointed out that Vince DeRose of CME, was involved in court this day and might not be able to join in, and that Union had indicated that since the discussions might lead into negotiations, they felt that they should not attend this day. Union did comment that they were still available to answer any questions that might arise to assist the committee in reaching its goals.

2. Action Items and System Reliability Index – K. Irani/M. Giridhar

(A copy of this presentation is included as Appendix E)

Prior to the commencement of Enbridge's presentation, Direct Energy asked if it made sense to review the comments made by IGUA and AEGENT first and also to address a question from Direct Energy that was missed in the previous meeting

Action Items about the "Discount" factor applied to the load shedding capabilities of interruptible customers. DE recalled that the discount factor was 40% and that he wanted to understand what that represented in interruptible volume.

Malini Giridhar indicated that the IGUA and AEGENT comments have been incorporated into the presentation that will be made and the committee could discuss those at that time.

Malini apologized for missing Direct Energy's question, decided to address it at this time. She started by saying that the discounting on contract demand would be better described as a "diversity" factor rather than a "discount" factor, and that it attempted to address the fact that not all interruptible customers are peaking on peak days, for example some are production sensitive, while others are heat load sensitive.

Ian Macpherson added that during curtailment exercises they discount the total 170,000 GJ contract demand for curtailment customers to reflect the fact that many interruptible customers may not be consuming on that day. In other words for planning purposes, Enbridge only counts on the availability of 60% of the curtailment contract demand, or about 102,000 GJ of the total 170,000 GJ contract volume.

AEGENT followed up on this discount factor issue with a question about Slide 2 in the upcoming "Action Items and System Reliability Matrix System Reliability" presentation, referring to the "Curtailment (firm)" volumes for the CDA and EDA of 110,000 and 33,000 respectively, totaling 143,000 GJs; asking if this 143,000 represented the discounted curtailment volume. Malini clarified that this represents the CDS volume that doesn't really get off the system on peak days; but she said that she will confirm that and provide clarification to the committee of the curtailment volumes that are planned for on peak days. She offered to do that by email.

IGUA asked what kind of customers are in that interruptible class. Ian Macpherson responded that any customer consuming more than 340,000 cubic meters in rate classes 170, 145 (with 16 hours notice) and 145 (with 72 hours notice) is eligible. There are about 233 customers in those rate classes and they include apartments, hospitals, manufacturing facilities, and so on.

In response to another question from IGUA, Ian pointed out that very few of the customers in these classes would have a high load factor and those customers with load factors of 80% or over are generally found in rate class 115. The lower load factor on the general interruptible customer leads to this discounting, since they would not be drawing contract demand on a steady and consistent basis.

Malini provided further clarification about the volume that is used for planning purposes as curtailment volume. She said that the amount of curtailment is based upon the forecast of demand from curtailment customers, which was included in the peak day demand forecast. Since the forecast includes Enbridge's best estimate of what will actually be consumed that day, it would reflect the forecast of the actual usage of the interruptibles, which is estimated at 60% of their contract volumes. It is only that 60% of contract demand volume that would be considered eligible for curtailment.

AEGENT tried to reconcile the curtailment (firm) volumes on slide 2, reported to be CDS volumes (143,000 GJs), with expected 60% curtailment volume of 102,000 GJs, saying that the 143,000 CDS volume would indicate that interruptibles are actually consuming much more than the discount factor suggests. Enbridge offered to try to clarify these two volumes and to report back to the committee.

Keith now began the Enbridge presentation on action items from the previous meeting. He started by correcting some values on slide 3 of the presentation. First under EGD Hypothetical, the potential shortfall should have been 682,000 GJ, not the 384,000 shown on the slide. That makes the potential shortfall 383,000 rather than the 85,000 shown on the slide. He indicated that he would revise the slide deck and recirculate it to the committee. Everyone agreed that we would include the revised version in the Notes.

Slide 2 of the Action Item slide deck showed the various shortfall scenarios with peaking and curtailment added, based upon Enbridge's 39.5 DD Peak Day criteria. This reduced the shortfall projections for the CDA to 0 in the Jan.2009 scenario, 85,000 GJs in the EGD Scenario and 1,770,000 GJs for the Sept 2009 line break scenario. The shortfalls for the EDA were reduced to 0 to 32,000 GJs for the same three scenarios.

Slide 3 showed the same three scenarios based upon the Historic Peak Day of 43.9 DD, resulting in CDA shortfalls of 33,000, 383,000 and 715,000 for the three scenarios, and EDA shortfalls of 0-86,000 GJs. In both of the slide 2 and 3 the analysis were based upon customers downstream of the CDA being successful at securing all of the capacity that was available to them.

Slide 4 was in response to a VECC question asking for the $5 million IT costs to be included in the customer impact analysis. The analysis indicated that the Vertical Slice IT incremental bill impacts for Rate 1 customers would be approximately 0.015 ¢/m^3 or $0.50 per year for the average customer.

The same slide responded to included customer impacts that resulted from replacing peaking with STFT. It showed an annual bill impact for Western T and Ontario T customers to be $8.00 and $11.00 respectively. This is based on allocating the STFT costs in the same manner as the peaking was previously rather than a volumetric allocation as in the earlier presentation. The difference was approximately $2.00 per year annually for large volume customers.

The next slides 5 to 30 inclusive identified all of the comments received from committee members for inclusion into the System Reliability Matrix for the options and the impacts. It was agreed that the committee would not go into a detailed analysis of these comments at this time, but would instead move on to hear Enbridge's proposed solution to the System Reliability issue.

3. Eastern Canadian Mutual Assistance Plan (ECMAP) – Malini Giridhar

(A copy of this presentation is included in Appendix F)
Before commencing the presentation of Enbridge's proposal, Malini presented information to the committee about the "Eastern Canadian Mutual Assistance Plan" or ECMAP.

Malini explained that it was coming to the committee at this point because it was referenced in an unbundling paper filed by Enbridge in 1999 referring to ECMAP, IGUA followed-up by inquiring about ECMAP. Enbridge responded to IGUA off-line and decided to bring ECMAP to the committee as added information about system reliability.

Malini indicated that the plan has been in place for many years and it has several members, including: City of Kitchener; City of Kingston; NRG; EGD, GMi, Union Gas, and TCPL. It is basically a self-help plan established to facilitate neighboring utilities and pipelines to provide assistance to one another in the event that any party experiences a serious supply problem. In essence, if one utility has excess capacity, while a neighboring utility is facing a risk of losing firm customers, then the utility with excess capacity could direct its excess to the utility in trouble.

The slide presented on this topic detailed some of the terms of the agreement, first describing Level 1 and Level2 supply shortfall conditions. Malini indicated that each utility reacts to the two conditions differently depending upon their supply assets and characteristics. In Enbridge's circumstances, it reacts to a Level 1 condition through curtailment, maximizing storage and peak shaving and by going to the marketplace for additional supply. A Level 1 condition does not invoke ECMAP.

A Level 2 condition is defined as a situation that results from an unplanned facility outage that causes or will likely cause a supply shortfall to firm customers and cannot be managed under Level 1 conditions.

ECMAP provides a process where all or individual members may voluntarily, without any obligation whatsoever, allocate available natural gas and transportation service to assist a member in a Level 2 condition. The assistance is provided for a minimum of 1 day and not more than 5 days, with the gas replaced in no more than 5 days, unless mutually agreed otherwise.

While ECMAP can assist where there is a local problem affecting a confined area, it cannot be depended upon for any widespread problem affecting neighboring utilities because under no circumstance will any member be required to contravene or breach its gas transportation tariff or any of its existing obligations including, without limitation, any firm and interruptible contracts with its shippers and obligations with any interconnecting pipeline.

Shell and Direct Energy asked if and when Enbridge had ever invoked a Level 2 ECMAP call and Enbridge confirmed that it has not invoked one to their recollection in the last 20 years.

IGUA asked if there were some criteria, (i.e. a shortfall amount) that were established for supply planning purposes at which Enbridge would call on ECMAP. Malini indicated that she was unsure if there was one established or what it might be, but said she would get that answer for IGUA. IGUA also asked if Enbridge could determine if there was some volume of emergency supply that Enbridge used in its planning mock-runs as an amount that could be obtained from the ECMAP call.

Enbridge agreed to report any details they could about how ECMAP was positioned as an emergency supply tool, but advised the committee that ECMAP could not be planned upon as a supply asset for system reliability planning because; 1) it is voluntary; and 2) it would not be available if the other member utilities were involved with the same supply restriction; such as a TCPL pipeline problem, or widespread cold temperatures. IGUA focused their question by asking Enbridge if it has included some amount of available capacity from an ECMAP member in any of the mock scenarios in the last three years and what amount volume amount that was. IGUA understood that the ECMAP volume used might have many conditions associated with the nature of the supply shortfall mock run.

Before moving on to the next presentation, IGUA asked TCPL if they could report on the latest information about turnback on TCPL. TCPL indicated that it would be posted on their website very soon. IGUA asked if someone could forward that information or an appropriate link to him when it was available.

4. EGD Proposal for System Reliability – Malini Giridhar

(Commencing with Slide 3 of the presentation contained in Appendix C)

4.1. Background

Malini began by explaining that she wanted to set the stage for their proposal by reviewing some of the important pieces of past discussions.

Slide 4 reviewed the Board Decisions and Orders that recently dealt with the system reliability issue and this consultation process. She highlighted the following points:

- The Board concluded that the system reliability issue raised by Enbridge must be addressed.
- The Board agreed with Enbridge that a prudent system operator does not wait for the system to fail but rather manages with a view to preventing outages, and to containing or removing any foreseeable risk to system reliability".
- Generally, parties acknowledged that system reliability is absolutely crucial not only for gas customers but also to the continuing integrity of the de-regulated gas marketplace in Ontario.
- The Board viewed that a long term resolution of the system reliability issue is needed. While the Board was comfortable that the Board's interim resolution would meet reliability requirements in the short term, it was not assured that the appropriate long term resolution had been found.
- The Board also stated that EGD should "…undertake consultations with all stakeholders to fashion a permanent resolution."

4.2. Committee Milestones

Malini reviewed significant milestones in the consultation process outlined on slide 5:

Nov 20, 2009 meeting:

- Options discussed: Vertical Slice, Interim Solution, Backstopping, Curtailment of LV firm customers.
- Comparison with Eastern Canadian LDCs, including Union South, Union North and Gas Met in terms of design day and the nature of their markets and supply assets;

Jan 21, 2010 meeting:

- New options discussed: Firm deliveries proposed by Shell and Short Haul build suggested by Direct Energy
- EGD provided additional volumes information by customer type

Feb 25, 2010 meeting:

- TCPL presentation;
- Consideration of two new options replacing peaking with STFT; and changes to the design degree day

April 8, 2010 meeting:

- DE presentation
- Capacity outage scenarios & resulting shortfall
- Customer rate impact from options.

CCC asked EGD for the costs of the degree day change option and EGD pointed to slide 8 of the April 8th presentation for the answer. Responding further to that question and added questions for IGUA, Enbridge said those costs were based upon the historic cold day of 43.8, rather than 39.5 current design day DD.

Enbridge confirmed that the allocation would be based on heat sensitivity. If consultations concluded that the change was sparked by system reliability concerns, the costs would be allocated by annual volumes, but if discussions with the committee concluded that it was sparked by insufficient firm supply that costs would continue to be allocated by peak day supply.

On slide 8, on the Apr 8th presentation the "$19" was based on the peak allocator. That number would be lower if the allocation was done by annual volume; conversely the number for large volume would be something higher than the 0.1 ¢/m^3 if the allocator changes to annual volume.

4.3. The System Reliability Issue

EGD's slide 6 attempted to summarize the System Reliability Issue by first saying that extensive use of discretionary supply services during periods of high demand can compromise system reliability.

Slide 6 also drew two conclusions being:

1. Direct purchase contracting practices, peaking supplies and reliance on curtailment must be reviewed; and
2. Different compositions of exposure in CDA and EDA may require different solutions

The slide also showed two pie charts, one for the CDA and one for the EDA, showing the supply portions and more importantly the portions identified as "exposed volumes" from the TCPL presentation. EGD further broke down that exposed volume into the three components that contribute to the exposed volume, those being: Direct Purchase; Peaking; and Curtailment. The portions of the exposed volumes for those three components were: 56%, 26% and 16% respectively in the CDA and 16%, 59% and 25% respectively in the EDA.

In response to an AEGENT question about the curtailment component, Malini indicated that the percentage for curtailment represented the volume associated with curtailment customers that expect to consume gas on the peak day.

The percentages associated with the Direct Purchase were not surprising to Enbridge based upon the high levels of turnback in the CDA and the relatively lower levels of turnback in the EDA.

Shell commented that the indication of CDS volumes does not necessarily show that customers are unable or unwilling to curtail, but may just be indicating that CDS volumes are available and that there is no need to curtail. Malini agreed with that point and added that there is often also a price consideration. However, she added that once a customer decides to consume in a curtailment situation, the problem may be that the CDS does not get delivered, and they still do not get off the system.

Enbridge confirmed that if they can firm up the contract terms with curtailment customers that the dependable curtailment volumes would improve. Enbridge also confirmed that the majority of large curtailment customers do have an alternate energy source and could curtail if required. With these confirmations IGUA asked Enbridge to attempt to restate the value of the curtailment capacity based upon the amount that they can reasonably expect to receive from curtailment customers.

Malini tried to clarify the matter further by saying that there are about 40-50 customers on Rate 170, and 180 on Rate 145. The 40 to 50 customers on Rate 170, that have 4 hours curtailment notice, generally have backup capabilities, whether they choose to use it or not. The 180 customers on rate 145 generally have no backup and Enbridge is now realizing that most of them do not have any plans to get off of gas if required to do so. It is this group that Enbridge would like to focus on to tighten up their responsibilities for curtailment and asked stakeholders to assist with this focus. Whether or not these customers are taken off of curtailment arrangements still remains a moot point in the calculation of shortfall volumes, in that even if they are removed from the curtailment rate classes, they are still customers that cannot be shut down and therefore remain part of the shortfall volume.

Enbridge agreed with a point made by Shell and provided additional clarification about this issue by saying that these volumes relate to curtailment customers who nominate CDS, but who's CDS does not show up and they continue to consume.

At this point the committee paused for a 15 minute morning break.

Morning Break

The committee reconvened at 10:45 AM and returned to the presentation of Enbridge's proposal. Bob Betts indicated that Vivian Krauchek of Enbridge had joined the committee by telephone during the break.

4.4. Assessing the Capacity to be Firmed-up

Enbridge moved on to slide 7 summarizing the shortfalls for the CDA and EDA using the TCPL scenarios and thereby providing guidance in establishing an appropriate amount to be firmed up.

IGUA questioned the numbers on the slide and Enbridge acknowledged that there were addition errors. The required corrections in the first row were to change the 176,000 to 178,000, and the 716,000 to 860,000, the 528,000 was correct. Enbridge agreed to correct those numbers and recirculate the slide deck, and all agreed that the revised slide deck would be the one included with the meeting notes.

Shell expressed its concern that these shortfall scenarios represent the "worst case", particularly because it assumes that everyone else gets their gas, but that Enbridge does not.

IGUA responded to Shell by asking Shell what else Enbridge could do in this case but to assume the "worst case" in the system planning exercise. Shell agreed but asked that the group not forget the assumptions that underpin the shortfall numbers.

4.5. The EGD Proposal

Enbridge now presented its proposed resolution on Slide 8.

Enbridge proposed to increase the use of pre-contracted STFT by 330,000 Gj/d in the winter season.

– Mass Market retailers receive a temporary assignment of 50,000 GJ/d of short haul capacity to CDA. EGD replaces assignment with STFT for five months, November to March, for sales customers until additional shorthaul capacity becomes available.

– EGD replaces 200,000 GJ/d of peaking supplies with STFT for three months, January to March.

– EGD acquires 80,000 GJ/d of STFT for three months to provide a reserve margin for one DD

Malini defined "pre-contracted STFT" to be STFT contracted before November 1 for volumes for the winter months of November to March inclusive, and indicated that this pre-contracted STFT was a good alternative to FT supply.

She explained the first bullet point as an attempt to react to concerns of retailers who said that they are not opposed to the idea of firming up, but really need additional access to short haul from Dawn to the CDA. Direct Energy made that suggestion on the premise that when additional capacity was available from Dawn to the CDA that they would have access to it. Malini said that Enbridge understood their concern and reviewed their asset portfolio and identified that they could offer 50,000 GJs/d of their Dawn to CDA to mass market retailers. She indicated that parties would have to agree on what the criteria would be for this allocation. She also said that this assignment would be reviewed when a build of additional shorthaul eventually became available.

She indicated that this would have to be allocated to the retailer until such time that some form of vertical slice IT solution was established that would allow the assignment to go to the customer instead of the retailer. It would be allocated on a temporary basis, to be reviewed every November.

CCC asked how Enbridge would determine which retailers would be eligible, and Malini replied that they have not determined that yet, but it would probably relate to size and distribution, and that the allocation would be in proportion to the Mean Daily Volumes.

In response to DE's question, Malini confirmed that this 50,000 GJ/d would be shorthaul FT for the entire year, but that Enbridge would replace it with "pre-contracted STFT" nominated before November 1 for the 5 winter months, from November 1st to March 31st. Malini added that the 50,000 is shorthaul FT that was previously used for system gas customers that would be made available to retailers. She further explained that the 50,000 GJ/d amount came about as a result of a November 1, 2010 turnback of Vector capacity that was matched with this shorthaul. While Enbridge had been planning on additional supply from Dawn to utilize the shorthaul, they decided to offer the capacity to retailers in an effort to resolve some of their concerns.

Enbridge explained to CCC that this will address retailer concerns that the portfolio held by Enbridge for its system gas customers had more diversity than the assets available to retailer's customers. Unfortunately this balancing of diversity would have a cost impact to the system gas customer.

Shell asked EGD if they had planned on shedding the 50,000 GJ/d anyway, or whether this proposal is a direct result of Enbridge's attempt to settle this matter. Malini confirmed that this proposal was made to resolve retailer's concerns and that Enbridge would otherwise have retained the shorthaul in question.

In response to a question from AEGENT, Malini indicated that the 50,000 GJ/d would be made available to retailers for 12 months because they have an obligation to deliver into the CDA 12 months of the year and Enbridge is basing this proposal on the expectation that the retailers will honour that obligation.

IGUA asked if it is less expensive for Enbridge to hold STFT for 5 months of the year versus holding the shorthaul from Dawn for 12 months. Enbridge confirmed that is not less expensive and that the proposal will represent a higher transportation cost for system gas customers.

There was no discussion about the 2nd bullet point in the proposal, but the 3rd bullet point did spark some questions and discussion. It described the proposal for the addition of 1 degree day to the peak day design, to create a reserve margin equivalent to 80,000 GJ/d. That additional 80,000 GJ/d reserve would be apply for three months January to March, and would be underpinned by STFT.

Malini indicated that others such as Gaz Met have added a reserve capacity to their peak day design calculations, and in Enbridge's case this 1 DD reserve would bring the total additional firm capacity up to 330,000 GJ/d, which is what Enbridge believes it needs based upon the risk scenarios discussed in this consultation.

In response to a question from Shell, Enbridge confirmed that this would effectively change Enbridge's design degree day to 40.5 versus the current 39.5, and Union's 44 degree days.

AEGENT expressed its opinion that while they could probably support the change in the degree day value, they did not see it as a solution to system reliability, on the basis that if it is needed to address an inappropriate design value it is completely weather related, not related to the amount of firm transport. Malini agreed, but indicated that this would be a "reserve margin", that would mitigate the risk of both unusual weather conditions and system restrictions that might occur in the coldest temperatures. The reserve margin would assist greatly in reducing the risks Enbridge's sees in the current lack of firm transport for all customers. If the 80,000 was not available from the 1 DD reserve, it would have to be added as FT in some other way.

Another general question from Direct Energy related to the fact that in the original application, Enbridge only asked for an additional 200,000 GJ of FT, but this proposal is for 330,000 GJs. Malini acknowledged that and indicated that this consultation has provided additional evidence that the potential risks of shortfall are greater than 200,000 and that information was not available to Enbridge for the last application.

This consultation has also helped Enbridge recognize that peaking services cannot be considerable as a dependable supply source in restricted transportation scenarios.

A question was asked about the additional 40,000 GJs of FT resulting from the Board's interim resolution and Enbridge agreed that this proposal would replace the Board's interim resolution.

DE asked how this proposal would be viewed as a long term resolution; Malini asked if she could come back to that question.

Moving on to Slide 9, "Customer Impact", Malini explained that Enbridge tried to identify the rate impacts of each of the 3 proposal components on Rate 1, Rate 6 and large volume customers, using current gas costs and tolls. She also clarified that Enbridge could not determine the impact on Ontario-T customers because EGD does not determine their transportation charges, she referred the committee to information available on "Energy Shop" showing a wide variation in rates by retailer, ranging from the low being Enbridge's 4.66 ¢/m^3, up to a retailer's high of 6.9 ¢/m^3.

The customer impacts on slide 9 collectively added up to 0.39 ¢/m^3 for Rate 1 (or $12.00 total annual for the average customer), 0.37¢/m^3 for Rate 6 and 0.21 ¢/m^3 for the large volume customer remaining on system.

In response to a question for CCC about what factors could influence these costs in the future, Enbridge indicated that this relationship would be affected by pipelines tolls, whether up or down, and the relative spreads between supply points because this concept is based upon shifting supply from Chicago/Dawn and AECO (Empress).

CCC asked for clarification on slide 9, as to whether the costs are strictly attributable to system gas customers. Malini replied saying that the first row affects strictly System Gas and Western-T customers, the second row affects all customers and the third row also affects all customers. She said they would add that information to this slide.

Malini and Keith noted another change to this slide in that on the third row, Backstopping should be removed and also the phrase "Provided to Ontario T only/" should also be removed. Malini indicated that they would make these changes in the redistributed packaged.

Responding to a question from Shell, Malini indicated that the reserve margin cost impact is spread evenly across large and small volume customers because it is deemed to be best allocated by volume.

Enbridge moved on to Slide 10 which summarized some additional changes they would be seeking as part of their proposed long term resolution. Malini indicated that it would be Ian Macpherson's group that would be moving these changes forward.

First they would restrict large volume customers' ability to self suspend their deliveries in the winter season in the same manner as Union Gas does. This would basically require notice to EGD and acceptance by EGD if a large volume customer decides to shut down deliveries. This provides greater assurance about the amount of volume that will show up on any given day and provides more confidence for EGD that the customer will not consume when they suspend.

Prepared by Regulatory Support Services
(Div of R. J. Betts Enterprises Ltd.)

Shell suggested that these customers may need some flexibility to cut back under certain economic conditions. There was further discussion about that point based on the fundamental differences in Union's circumstances and EGD's, and the proximity of a liquid hub.

Enbridge agreed that they would be open to various suggestions about how this point could be handled including the concept of recallable approvals to suspend versus firm suspensions.

There was additional discussion about withholding approval to suspend and the criteria for doing so. It was noted that the criteria would have to reflect the supply conditions and whether the approval was being withheld for system reliability issues. Enbridge agreed that they would keep that point in mind as they consider the protocols.

Malini summarized Enbridge's concerns on this point by saying that:

1. They need to know with certainty, if a customer is suspending deliveries, because they are not consuming that volume on that day, and
2. They need to be able to balance the amount of consumption with the amount of delivery on any given day.

Enbridge agreed with AEGENT that the first point on this slide could be changed to read "Enbridge authorization required before large volume customers could self suspend in the winter season."

The next bullet point, "Strengthen EGD's contractual ability to suspend service to large volume customers who fail to deliver", this would be short of installing expensive equipment to remotely control their supply and could allow Enbridge to withdraw the customers authorized volume.

Next "Increase effectiveness of Curtailment" referred to the ideas presented by Ian during the last meeting. Enbridge indicated that they would move those concepts forward using consultation with interested parties.

In response to a question from Direct Energy, Enbridge indicated that they would want to implement their proposal outlined on slide 8 for November 1st, but that the changes to large volume protocols would be done later, for their next rate case. After some group discussion it was recognized that there could be some difficulty in implementing some aspects of the proposal for November 1st. In particular, winter season STFT is offered July 1, and without an assurance that EGD can contract for winter season STFT, EGD would not be able to assign short haul FT.

DE went on to a question about "Limit turnback in the EDA" and whether the regulatory approval process would affect implementation timing. Malini indicated that this will take some thinking about how this turnback would be structured, but it was agreed that the regulatory approval would be required for any limitation of current rights and changes to the Rate Order. All agreed that if it was part of a settlement of this issue in this consultation, that the Board would probably find it acceptable.

Malini now answered DE's earlier question about whether this proposal was one that could be considered a "long term resolution" as requested by the OEB. She said in the

CDA she would consider this as a "long term resolution"; however, Enbridge would need a satisfactory solution for turnback in the EDA to be comfortable with this proposal lasting in the longer term.

Direct Energy asked if thought could be given to describing the types of "triggers" that could cause the Enbridge proposal to be subjected to another review. Enbridge agreed that they would give that some thought.

TCPL asked if they understood correctly that this proposal only requires direct marketers to come up with an additional 50,000 GJs and based upon the 40,000 that they have already come up with and the potential for turnback in the EDA that there could even be a lower requirement for marketers to firm up than they currently have.

Enbridge confirmed that could be the case, particularly if the turnback in the EDA could not be controlled, and potentially could be the case if parties take further advantage of turnbacks in the CDA. That thought caused Enbridge to say they would also reconsider the CDA in this respect.

Finally Slide 11 showed how the Enbridge proposal reduces the "Exposed Volume" originally shown on Slide 6 from 53% to 32% in the CDA, and 26% to 17% in the EDA.

That closed the presentation portion, at which point IGUA thanked Enbridge for bringing forward what they viewed at this point as a very "constructive proposal".

5. Next Steps

Bob Betts asked the group how they would like to proceed from this point forward.

First with respect to Note Taking, all agreed that the Notes have been very beneficial, but that there may be discussions that should not be recorded in the notes. The committee agreed that it would continue to try to capture some content in notes, in order to continue to inform the other stakeholders, and that they would ask the Facilitator to apply the first level of judgment as to what would be appropriate to note and what would be best kept in confidence. Bob Betts indicated that he could apply his judgment first to what items should be get confidential, and circulate the record to all committee members for their comments on the draft notes prior to circulation to any non-committee parties. All agreed that the committee would try it that way.

Second, Enbridge can bring Counsel David Stevens to assist in preparing a Settlement Document for consideration of committee members, and for presentation to the larger stakeholder group.

Third, Enbridge agreed that they would try to circulate the next package of information as far ahead of the May 17th meeting as possible. It was agreed that Enbridge could use today's proposal presentation, and just incorporate additional information and changes on it as a foundation for the material for the 17th.

The group agreed to add May 20th to their calendars for mass market unbundling and that it would probably only require the morning.

The group also agreed to keep May 27th open tentatively for the presentation to the larger group.

All agreed to reconvene on May 17th and 18th to continue with the system reliability discussions.

Adjourn

The meeting adjourned at 12:40PM.

Note to Readers:

Action items arising from this meeting can be found in Appendix D.

Appendices

Appendix A: Meeting Agenda April 30, 2010

STAKEHOLDER CONFERENCE
Friday, April 30, 2010
9:00 AM – 12:00 PM
Ontario Energy Board
2300 Yonge St., 25th Floor
West Hearing Room
System Reliability

AGENDA

9:00 - 9:10 am	**Opening Remarks -** Bob Betts, Facilitator • Welcome and Housekeeping Items • Objectives and plan for this meeting
9:10 – 12:00 am	**EGD System Reliability Presentation -** M. Giridhar/K. Irani • Action Items and System Reliability Matrix • EGD Proposal for System Reliability

Adjourn

Lunch

Appendix B: Participant Listing

Stakeholders

Attendee	Organization
Frank Brennan	AEGENT
Ric Forster	Direct Energy
Ian Mondrow	IGUA
Colin Schuch	Ontario Energy Board
Paul Dumaresq	Shell Energy
Paul Kerr	Shell Energy
Murray Ross	TCPL
Lisa DeAbreu	TCPL
Julie Girvan	VECC & CCC

Enbridge Representatives

Attendee	Position
Malini Giridhar	Director, Energy Supply & Policy
Norm Ryckman	Director, Regulatory Affairs
Keith Irani	Manager, Energy Supply Services
Hilmi Muhammad	Manager, Energy Forecasting and Planning
Robert Bourke	Manager, Regulatory Proceedings
Ian Macpherson	Manager, Direct Purchase
Vivian Krauchek	Manager, Gas Supply
Edith Chin	Manager Upstream Regulatory Strategy &Major Projects

Other

Bob Betts	Facilitator, Regulatory Support Services

Appendix C: EGD System Reliability Presentation - The Proposal (REVISED) – M. Giridhar

Appendix C

ENBRIDGE

System Reliability Working Committee

April 30, 2010

System Reliability Working Committee Opening Remarks – Bob Betts, Facilitator

- Welcome & Housekeeping Items
- Objectives and Plan for the Meeting
    - Action items and System Reliability Matrix
    - System Reliability Proposal
- May 17-18 Settlement Conference

EGD System Reliability Presentation

M. Giridhar

ENBRIDGE

Review of Board Decision

OEB Decision and Order

- The Board therefore concludes that the system reliability issue raised by Enbridge must be addressed.[1]
- The Board agrees with Enbridge that a prudent system operator does not wait for the system to fail but rather manages with a view to preventing outages, and to containing or removing any foreseeable risk to system reliability".[2]
- Parties have also acknowledged that system reliability is absolutely crucial not only for gas customers but also to the continuing integrity of the de-regulated gas marketplace in Ontario.[3]
- The Board is of the view that a long term resolution of the system reliability issue is needed. While the Board is comfortable that the Board's interim resolution will meet reliability requirements for the coming winter, it is not assured that the appropriate long term resolution has been found.[4]
- The Board also stated "…and to undertake consultations with all stakeholders to fashion a permanent resolution."[5]

[1] Decision And Order Phase 2 July 14, 2009, p.7 para 5.
[2] IBID p.7, para 2 [3] IBID p. 7 para 2 [4] IBID p.11 para 1 [5] IBID p.8 para 1

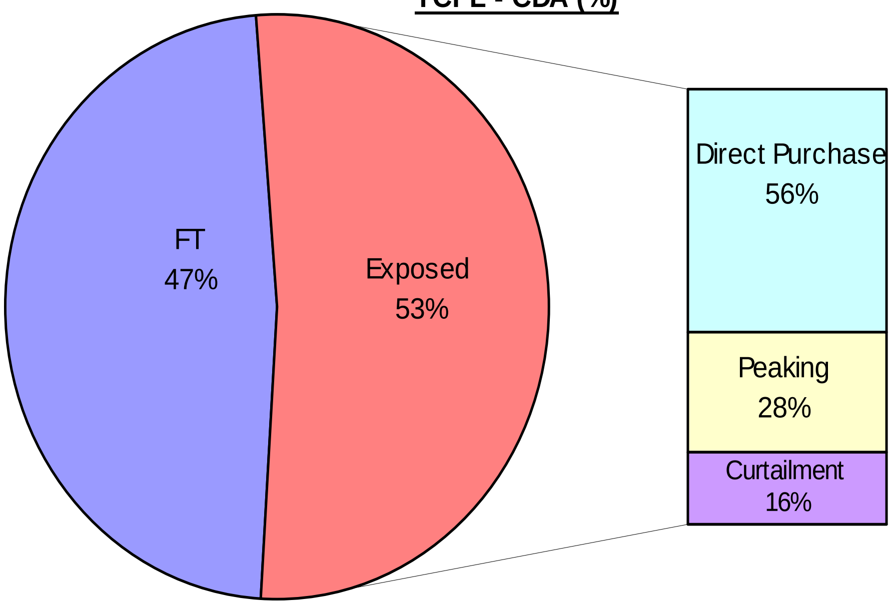
Review of Working Committee Meetings

Meeting	Highlights
Nov 20, 2009	• Options discussed: Vertical Slice, Interim Solution, Backstopping, Curtailment of LV firm customers. • Comparison with Eastern Canadian LDCs
Jan 21, 2010	• New options discussed: Firm deliveries, Short Haul build • EGD Volumes by customer type
Feb 25, 2010	• TCPL presentation; • New options discussed: replace peaking with STFT; change to design degree day
April 8, 2010	• DE presentation • Capacity outage scenarios & resulting shortfall • Customer rate impact from options.

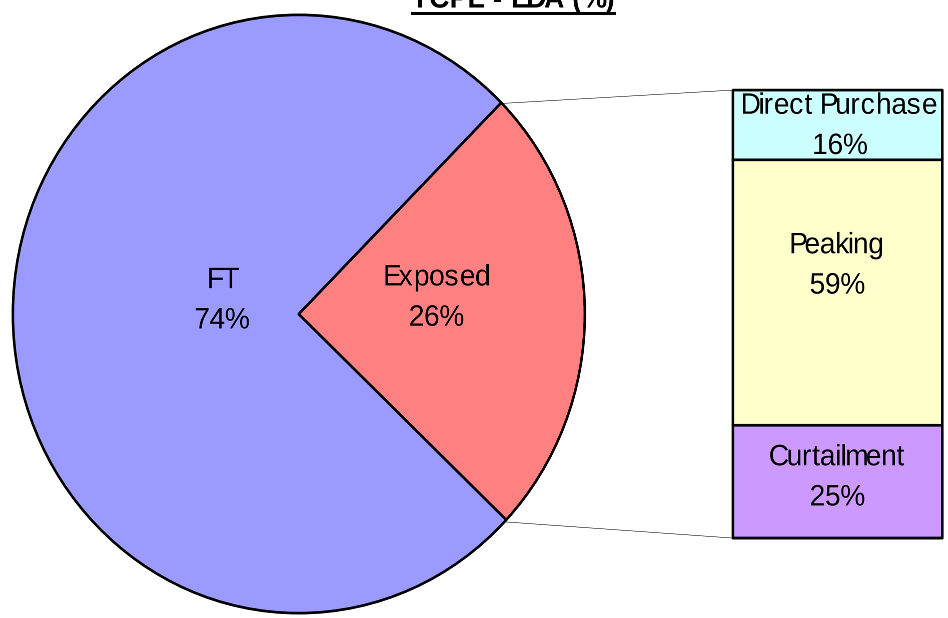
System Reliability Issue

- Extensive use of discretionary services during periods of high demand can compromise system reliability
- EGD conclusion
  - Direct purchase contracting practices, peaking supplies and reliance on curtailment must be reviewed
  - Different compositions of exposure in CDA and EDA may require different solutions

TCPL - CDA (%)



TCPL - EDA (%)



Possible Impact of Capacity Outages on EGD Franchise (Revised in *Italics*)

Capacity Outage Scenario (GJ)	**600,000** **Jan 2009**	**950,000** **EGD Crisis Scenario**	**1,770,000** **Sep 2009**
Current Design Day (39.5 DD)	*178,000*	528,000	*860,000*
Historical Peak Day scenario (43.8 DD)	530,000	880,000	1,212,000
Current peak day with high wind conditions (impact of 23 m/hr wind speed vs. 9 m/hr)	*478,000*	828,000	*1,160,000*

What is the appropriate quantity to be firmed up?

EGD Proposal

Increase the use of pre-contracted STFT by 330,000 Gj/d in the winter season

- Mass Market retailers receive a temporary assignment of 50,000 GJ/d of short haul capacity to CDA. EGD replaces assignment with STFT for five months for sales customers until additional shorthaul capacity becomes available.

- EGD replaces 200,000 GJ/d of peaking supplies with STFT for three months.

- EGD acquires 80,000 GJ/d of STFT for three months to provide a reserve margin for one DD

EGD Proposal - Customer Impact

		Rate 1		Rate 6	Large Volume
Option	**Firm Capacity (GJ/d)**	**Impact** *(¢/m³)*	**Annual $**	**Impact** *(¢/m³)*	**Impact** *(¢/m³)*
Assign SH capacity and contract STFT *Sales and Western T*	50,000	0.09	$3.00	0.09	0.10
Replace Peaking with STFT *All customers*	200,000	0.19	$6.00	0.17	0.00
Reserve margin *All customers*	80,000	0.11	$3.00	0.11	0.11

Note: Assumes current TCPL tolls. TCPL's toll proposal for 2011 would result in a reduction in cost by ~20%. Also, the analysis reflects current basis spreads between Aeco, Chicago and Dawn which are at historical lows. A higher basis would also lower toll impacts, due to the displacement of Dawn and Chicago with AECO purchases.

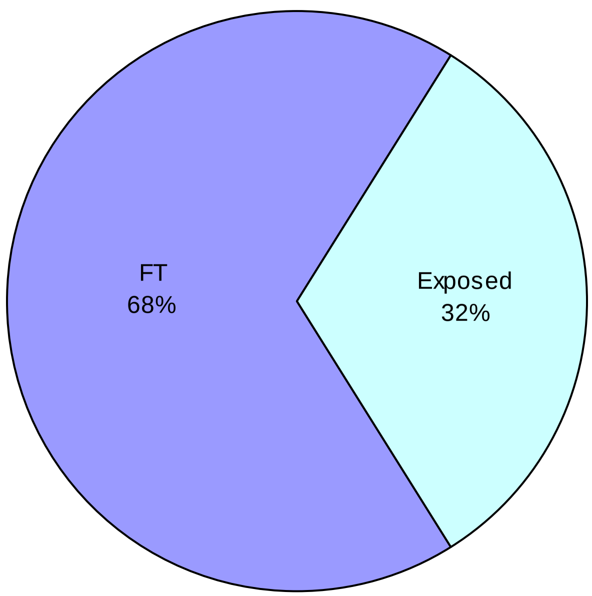
Other Proposed Changes

- Restrict large volume customers' ability to self suspend in the winter season
- Strengthen EGD's contractual ability to suspend service to large volume customers who fail to deliver
- Increase effectiveness of Curtailment
- Limit turnback in the EDA

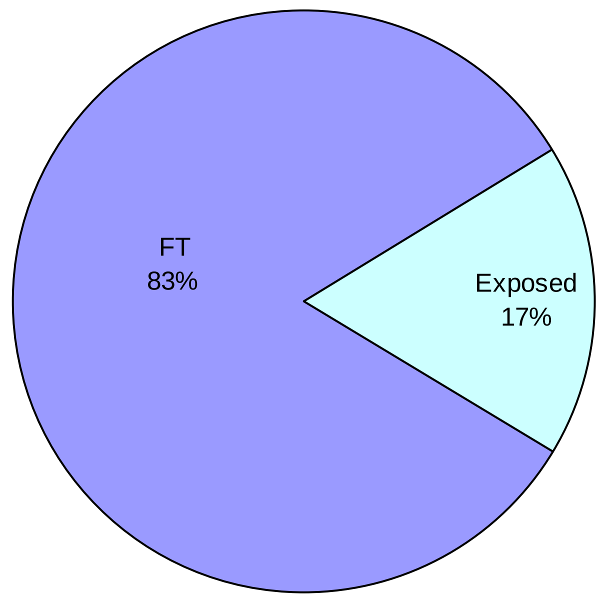
Impact of EGD Proposal on System Reliability

- EGD's proposal will significantly reduce reliance on "less assured" forms of discretionary services, while restricting the ability of large volume customers to draft the system if they fail to deliver and improving the effectiveness of curtailment

CDA Impact from Proposal - (%)



EDA Impact from Proposal - (%)



Note : Winter season STFT is treated as Firm. Exposed quantities can be further reduced by changes to large volume firm and interruptible rates/contracts

Appendix D: Summary of Action Items

From the System Reliability Committee Meeting 5
Held on April 30, 2010

Item	Page	Task	Responsibility
SR5.01	2	AEGENT followed up on this discount factor issue with a question about Slide 2 in the upcoming “Action Items and System Reliability Matrix System Reliability” presentation, referring to the “Curtailment (firm)” volumes for the CDA and EDA of 110,000 and 33,000 respectively, totaling 143,000 GJs; asking if this 143,000 represented the discounted curtailment volume. Malini clarified that this represents the CDS volume that doesn’t really get off the system on peak days; but she said that she will confirm that and provide clarification to the committee of the curtailment volumes that are planned for on peak days. She offered to do that by email.	Enbridge
SR5.02	3	AEGENT tried to reconcile the curtailment (firm) volumes on slide 2, reported to be CDS volumes (143,000 GJs), with expected 60% curtailment volume of 102,000 GJs, saying that the 143,000 CDS volume would indicate that interruptibles are actually consuming much more than the discount factor suggests. Enbridge offered to try to clarify these two volumes and to report back to the committee.	Enbridge
SR5.03	3	Keith now began the Enbridge presentation on action items from the previous meeting. He started by correcting some values on slide 3 of the presentation. First under EGD Hypothetical, the potential shortfall should have been 682,000 GJ, not the 384,000 shown on the slide. That makes the potential shortfall 383,000 rather than the 85,000 shown on the slide. He indicated that he would revise the slide deck and recirculate it to the committee. Everyone agreed that we would include the revised version in the Notes.	Enbridge
SR5.04	5	IGUA asked if there were some criteria, (i.e. a shortfall amount) that were established for supply planning purposes at which Enbridge would call on ECMAP. Malini indicated that she was unsure if there was one established or what it might be, but said she would get that answer for IGUA. IGUA also asked if Enbridge could determine if there was some volume of emergency supply that Enbridge used in its planning mock-runs as an amount that could be obtained from the ECMAP call. Enbridge agreed to report any details they could about how ECMAP was positioned as an emergency supply tool, but advised the committee that ECMAP could not be planned upon as a supply asset for system reliability planning because; 1) it is voluntary; and 2) it would not be available if the other member utilities were involved with the same supply restriction; such as a TCPL pipeline problem, or widespread cold temperatures. IGUA focused their question by asking Enbridge if it has included some amount of available capacity from an ECMAP member in any of the mock scenarios in the last three years	Enbridge

		and what amount volume amount that was. IGUA understood that the ECMAP volume used might have many conditions associated with the nature of the supply shortfall mock run.	
SR5.05	5	Before moving on to the next presentation, IGUA asked TCPL if they could report on the latest information about turnback on TCPL. TCPL indicated that it would be posted on their website very soon. IGUA asked if someone could forward that information or an appropriate link to him when it was available.	TCPL
SR5.06	8	IGUA questioned the numbers on the slide and Enbridge acknowledged that there were addition errors. The required corrections in the first row were to change the 176,000 to 178,000, and the 716,000 to 860,000, the 528,000 was correct. Enbridge agreed to correct those numbers and recirculate the slide deck, and all agreed that the revised slide deck would be the one included with the meeting notes.	Enbridge
SR5.07	11	CCC asked for clarification on slide 9, as to whether the costs are strictly attributable to system gas customers. Malini replied saying that the first row affects strictly System Gas and Western-T customers, the second row affects all customers and the third row also affects all customers. She said they would add that information to this slide. Malini and Keith noted another change to this slide in that on the third row, Backstopping should be removed and also the phrase “Provided to Ontario T only/” should also be removed. Malini indicated that they would make these changes in the redistributed packaged.	Enbridge
SR5.08	12	There was additional discussion about withholding approval to suspend and the criteria for doing so. It was noted that the criteria would have to reflect the supply conditions and whether the approval was being withheld for system reliability issues. Enbridge agreed that they would keep that point in mind as they consider the protocols.	Enbridge
SR5.09	12	Enbridge agreed with AEGENT that the first point on this slide could be changed to read “Enbridge authorization required before large volume customers could self suspend in the winter season.”	Enbridge
SR5.10	13	Direct Energy asked if thought could be given to describing the types of “triggers” that could cause the Enbridge proposal to be subjected to another review. Enbridge agreed that they would give that some thought.	Enbridge
SR5.11	13	Second, Enbridge can bring Counsel David Stevens to assist in preparing a Settlement Document for consideration of committee members, and for presentation to the larger stakeholder group.	Enbridge
SR5.12	13	Third, Enbridge agreed that they would try to circulate the next package of information as far ahead of the May 17th meeting as possible. It was agreed that Enbridge could use today’s proposal presentation, and just incorporate additional information and changes on it as a foundation for the material for the 17th.	Enbridge

Appendix E: Action Items and Matrix (REVISED) – K. Irani/M. Giridhar

Appendix E

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Action Items and System Reliability Matrix
System Reliability
Working Committee

April 30, 2010

Action items: Add Peaking and Curtailment

***SR4.06:** IGUA asked that the chart on Slide 7* be restated on the assumption that there was complete confidence in curtailment, and peaking was underpinned with firm supply.*

System Outage Scenario	Jan 2009 600,000	EGD Hypothetical 950,000	Sep 2009 1,770,000
Current Peak Day Criteria: 39.5 DD			
CDA			
Non Firm/Exposed Quantity	716,000	716,000	716,000
Potential shortfall	34,000	384,000	716,000
Add: STFT – Peaking	189,000	189,000	189,000
Add: Curtailment (firm)	110,000	110,000	110,000
Potential shortfall	0	85,000	417,000
EDA			
Non Firm/Exposed Quantity	144,000	144,000	144,000
Potential shortfall	0 to 144,000	0 to 144,000	144,000
Add: STFT – Peaking	79,130	79,130	79,130
Add: Curtailment (firm)	33,000	33,000	33,000
Potential shortfall	0 to 32,000	0 to 32,000	32,000

*** Corrected from Final System Reliability Committee Notes, Appendix D, Summary of Action Items reference to Slide 8**

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Action items: Add Peaking and Curtailment .. Continued (Revised in *Italics*)

SR4.06: *IGUA asked that the chart on Slide 7* be restated on the assumption that there was complete confidence in curtailment, and peaking was underpinned with firm supply.*

System Outage Scenario	Jan 2009 600,000	EGD Hypothetical 950,000	Sep 2009 1,770,000
Historical Peak Day Criteria: 43.9 DD			
CDA			
Non Firm/Exposed Quantity	1,014,000	1,014,000	1,014,000
Potential shortfall	332,000	*682,000*	1,014,000
Add: STFT – Peaking	189,000	189,000	189,000
Add: Curtailment (firm)	110,000	110,000	110,000
Potential shortfall	33,000	*383,000*	715,000
EDA			
Non Firm/Exposed Quantity	198,000	198,000	198,000
Potential shortfall	0 to 198,000	0 to 198,000	198,000
Add: STFT – Peaking	79,130	79,130	79,130
Add: Curtailment (firm)	33,000	33,000	33,000
Potential shortfall	0 to 86,000	0 to 86,000	86,000

*** Corrected from Final System Reliability Committee Notes, Appendix D, Summary of Action Items reference to Slide 8**

Action items: Add Implementation Costs, Show Peaking Option dedicated to Peaking and not Multiple Uses

SR4.07: *IGUA asked Enbridge if they could redo the Peaking option using the assumption that it was not employed for multiple uses, but instead was dedicated to the use for peaking*

		Rate 1		Rate 6	Large Volume
Option	**Incremental Firm Capacity (GJ/d)**	**Impact** ***(¢/m³)***	**Annual $**	**Impact** ***((¢/m³)***	**Impact** ***(¢/m³)***
Vertical Slice (Transport & IT Implementation)	200,000	0.2	$7.5	0.2	0.2
Backstopping (Provided to Ontario T only)	200,000	0.4	$13	0.4	0.4
Design Day (Load Balancing)	350,000	0.6	$19	0.5	0.1
Replacement of Peaking with STFT	250,000	Sales & Western T 0.3 Others 0.4	Sales & Western T $8 Others $11	Sales & Western T 0.2 Others 0.3	Sales & Western T 0.0 Others 0.1

Note: Vertical Slice IT costs are approx.0.015 ¢/m3 or approx. 50 ¢/year for Rate 1. STFT costs (option 4) allocated based on the peaking allocator.

System Reliability Matrix

Impact of Options	System Reliability			Competitiveness	Ratepayer/ Stakeholder impacts	Term
Options	**Firm Transport**	**Incremental Supply (backstopping)**	**Load Reduction (curtailment of firm customers)**	**Impact on Competitive Market**	**Ratepayer & Stakeholder Impacts**	**Estimate Lead time**
1. Vertical slice	• firm contracts to delivery area	• not required	• not required	TCPL: None	- TBD CCC/VECC TCPL: • Enhanced security of supply •No change in cost for system supply customers •Cost change for DP customers – retail – at their supplier's discretion - wholesale – increased trans. costs	2-3 yrs

System Reliability Matrix

Impact of Options	System Reliability			Competitiveness	Ratepayer/ Stakeholder impacts	Term
Options	**Firm Transport**	**Incremental Supply (backstopping)**	**Load Reduction (curtailment of firm customers)**	**Impact on Competitive Market**	**Ratepayer & Stakeholder Impacts**	**Estimate Lead time**
2. Interim						
a. Board interim resolution	• firm transport to delivery area (Jan-Mar), increasing 10% each yr	• potential option	• potential option	TCPL: •Difficult to enforce which will lead to different interpretations by DP suppliers which will result in an uneven playing field.	Cost $xxx (CCC/VECC) TCPL: • Enhanced security of supply •No change in cost for system supply customers •Cost change for DP customers – retail – at their supplier's discretion - wholesale – maybe a small increase in trans. Costs	3-6 mths

System Reliability Matrix

Impact of Options	System Reliability			Competitiveness	Ratepayer/ Stakeholder impacts	Term
Options	Firm Transport	Incremental Supply (backstopping)	Load Reduction (curtailment of firm customers)	Impact on Competitive Market	Ratepayer & Stakeholder Impacts	Estimated Lead time
2. Interim						
b. EGD interim solution (modified)	• firm transport (% of MDV) to delivery area (Dec-Mar)	• potential option	• potential option	TCPL: •Would make the rules clearer than in the Board Resolution Option.	Cost to be Determined (CCC/VECC) TCPL: • Enhanced security of supply •No change in cost for system supply customers •Cost change for DP customers – retail – at their supplier's discretion -wholesale – maybe a small increase in trans. Costs	3-6 mths

Appendix E

System Reliability Matrix

Impact of Options	System Reliability			Competitiveness	Ratepayer/ Stakeholder impacts	Term
Options	**Firm Transport**	**Incremental Supply (backstopping)**	**Load Reduction (curtailment of firm customers)**	**Impact on Competitive Market**	**Ratepayer & Stakeholder Impacts**	**Estimated Lead time**
2. Interim						
c. Direct Energy	• firm transport to delivery area, frozen at 2010 levels	• potential option	• potential option	TCPL: •Difficult to enforce which will lead to different interpretations by DP suppliers which will result in an uneven playing field.	Cost to be Determined (CCC/VECC) TCPL: • Enhanced security of supply •No change in cost for system supply customers •Cost change for DP customers – retail – at their supplier's discretion - wholesale – maybe a small increase in trans. Costs	3-6 mths

System Reliability Matrix

Impact of Options	System Reliability			Competitiveness	Ratepayer/ Stakeholder impacts	Term
Options	Firm Transport	Incremental Supply (backstopping)	Load Reduction (curtailment of firm customers)	Impact on Competitive Market	Ratepayer & Stakeholder Impacts	Estimated Lead time
3. Backstopping service	• potential option	• required	• potential option	TCPL: •May encourage DP Suppliers to take more risk.	Cost? (CCC/VECC) TCPL: • Enhanced security of supply •Potentially high cost. The impact on system supply customers &DP customers would depend on cost allocation	1 year
4. Curtailment of firm customers	▪ not required	• not required	▪ required	TCPL: • None	Not Viable Option (CCC/VECC) TCPL •None if all costs allocated to those customers electing this option. •Question the benefit of this option.	1-2 years

System Reliability Matrix

Impact of Options	System Reliability			Competitiveness	Ratepayer/ Stakeholder impacts	Term
Options	**Firm Transport**	**Incremental Supply (backstopping)**	**Load Reduction (curtailment of firm customers)**	**Impact on Competitive Market**	**Ratepayer & Stakeholder Impacts**	**Estimated Lead time**
5. Firm Delivery/Financial rating	?	?	• potential option	TCPL: • Benefits the most financially stable suppliers which could result in a reduction in the # of suppliers & this competition	More Info (CCC/VECC) TCPL: •No increase in security of supply. •No change in cost for both system supply or DP customers	3-6 mths
6. EGD Design Day	• option to contract for incremental transport in winter	• potential option	• not required	TCPL: • None	TCPL: •Enhanced security of supply for system gas customers •Increased cost for system supply customers. Mayb e no change in cost for DP customers.	

System Reliability Matrix

Impact of Options	System Reliability			Competitiveness	Ratepayer/ Stakeholder impacts	Term
Options	**Firm Transport**	**Incremental Supply (backstopping)**	**Load Reduction (curtailment of firm customers)**	**Impact on Competitive Market**	**Ratepayer & Stakeholder Impacts**	**Estimated Lead time**
7. EGD Peaking contracts	• option to contract for incremental transport in winter	• potential option	• not required	TCPL: • None	TCPL: •Enhanced security of supply •Increased cost for both system supply or DP customers.	

System Reliability Matrix Response (Direct Energy)

Vertical Slice

- **System Reliability** - Suggesting that Vertical Slice ("VS") requires no backstopping would be to suggest that the assets are in place to provide capacity that is sufficient to meet take-away demand and that EGD is simply trying to address the deployment of the assets. DE would concur that no backstopping is required and that as long as the assets provide the necessary capacity the market will ensure that gas supply will meet gas demand.

- **Impact on Competitive Markets** - EGD's current customer transport rate ($1.25) reflects a transport portfolio with a weighting towards SHFT therefore to accommodate the successful implementation of VS a full unbundling of assets must be considered. DE has no interest in assuming the expensive long-haul ("LH") transport from EGD in any proportion that is not identical to the portion held by EGD as this would unnecessarily increase costs at the expense of the customer. Any allocation of assets must reflect the ownership of such assets by the customer; the assets must follow the customer.

- **Ratepayer/Stakeholder Impacts** – Precluding the stakeholders from the choice of participating in synthetic transport rates will impact their ability to provide customers market driven rates. Also, as the implementation of VS would require a broader unbundling of assets the cost associated with such implementation would be assumed by the ratepayers.

System Reliability Matrix Response (Direct Energy)

Interim Resolutions (Board, EGD & DE)

- **System Reliability** – These options, in their entirety, are unnecessary and costly as they unduly include months that are statistically not a reliability risk. In its ruling the Board noted "…that the risk to reliability of system arises on the coldest days of the year…" Based on historical data over the last 56 years the daily average temperature only exceeded -21 degrees Celsius (39 DD) 16 days of which none of those days occurred in December or in March. Considering the "…excess capacity available on TCPL's pipeline…" it is unnecessary to include December and March in an extended interim solution.

- **Impact on Competitive Markets** – Freezing the initial interim solution provides a somewhat balanced approach however modifying the interim solution, as proposed by EGD, would create an additional increased cost. Synthetic transport charges related to previously turned-back volumes would be unwound at current market rates which are considerably lower than the current LH TCPL tolls. A significant portion of these costs would be for periods that historically do not represent a reliability risk.

System Reliability Matrix Response (Direct Energy)

Backstopping/Short haul build

- **System Reliability –** EGD is in the best position to ascertain if they require incremental capacity. DE has no position regarding suitability of "new build" capacity into the EGD franchise area.

- As discussed by Enbridge the backstopping service creates a "…trade-off between duplication of capacity versus adequacy of contingency arrangements." DE agrees with the Board that "…Enbridge does not operate in a significantly restrained market; rather, the evidence suggests that there is excess capacity on the TCPL mainline which gives the Board additional confidence that peak day demands can be met…"

- **Ratepayer/Stakeholder Impacts –** If, as provider of last resort, EGD discerns that it is prudent to pursue "new build" those costs will be allocated to its ratepayers.

System Reliability Matrix Response (Direct Energy)

Firm Delivery / Financial Rating

- **System Reliability** – DE agrees with Shell that "gas will always arrive at a price unless there is truly a capacity issue." However, implying that a particular financial/credit threshold will resolve the suggested system reliability issue is offering up a financial solution to what EGD is promoting as a physical problem. Regardless, DE supports Shells effort to find a reasonable long-term solution and would consider accommodating a financial/credit solution. A majority of the "firm" delivered gas supply transacted by DE at CDA is with counterparty's that have the same or higher credit rating then TCPL (A-) or EGD (BBB+).

- **Impact on Competitive Markets –** There may be some marginal DP Eastern delivery clients of EGD that will be unable to obtain the necessary credit worthy contracts. Although there may be some non-competitive aspects to the proposal this can also be viewed as credit protection to EGD who will now have the benefit of dealing only with DP's that are maintaining a minimum credit/financial threshold. There could also be a material administrative cost to the larger commercial players who generate both proprietary and retail procurement activity. The comingled activity could create some challenges when attempting to isolate contracts.

- **Ratepayer/Stakeholder Impacts –** There would definitely be some cost to monitoring and oversight responsibility that would need to be passed on to the DP's and/or ratepayers.

System Reliability Matrix Response (Aegent)

1. Vertical Slice

- Enbridge would contract 200,000 GJ/d of long haul FT on TransCanada and then allocate to all Ont ABC customers a slice of each transportation contract (TCPL, Vector, Alliance,etc) held by Enbridge.
- We don't understand why the capacity needs to be long haul and why it needs to be FT and not STFT.
- By contracting for TCPL capacity only, Enbridge will be decreasing diversity of supply compared to what markets and suppliers can offer with delivered supply.
- Based on the information provided to date, large volume non-ABC customers are not considered to be a concern since they already rely of firm transportation.
- There doesn't seem to be any recognition that some DP customers rely on upstream diversions to the CDA from Iroquois, that TCPL indicated are essentially firm. During the Jan 13-15 period all upstream diversions were approved in the first nomination window.

2a Board Interim Solution

- We do not agree with Enbridge's interpretation of the Board's decision that the amount of transportation that needs to be firmed up increases by 10% each year.

2b Enbridge Interim Solution (Modified)

- It appears that this option would require all DP customers (ABC and non-ABC) to hold firm upstream transportation on 90% of their requirements. Seems inconsistent with option 1.
- Greatly reduces diversity of supply if it means having to contract on TCPL.
- There doesn't seem to be any recognition that some DP customers rely on upstream diversions to the CDA from Iroquois, that TCPL indicated are essentially firm. During the Jan 13-15 period all upstream diversions were approved in the first nomination window.

System Reliability Matrix Response (Aegent)

2c Direct Energy

- With the likelihood of additional excess capacity on TCPL, this requirement could be relaxed and reviewed from time to time.

3. Backstopping

- Enbridge would contract for 200,000 GJ/d of shorthaul FT
- We don't understand why Enbridge is proposing FT instead of STFT.
- It appears from the information that TCPL presented that transportation capacity is currently not an issue nor is likely to be going forward. The issue is related more to the contracting of the excess capacity.
- If Enbridge isn't aware of a supply failure until after the timely nomination has closed, how they propose to use the backstopping capacity?
- Contracting firm transportation for 365 days of the year and only using it one or two days a year seems uneconomic.

4. Curtailment of Firm Customers

- This option would apply to large volume firm customers.
- Most of these large volume customers have contracted for firm transportation capacity because they cannot accommodate an interruption to their gas supply.
- Cost of control valves may be prohibitive.
- Enbridge should consider discussing with the large power generators the idea of paying them for the use of their transportation capacity on days when other customers fail to deliver. This would be similar to Enbridge's existing peaking services.

System Reliability Matrix Response (Aegent)

5. Firm Deliveries/ Financial Rating

- Not sure this addresses the consequences of a supplier failing to deliver.

6. EGD Design Day

- Design day would increase from 39.5 degree day to a 43.9 degree day
- This doesn't do anything to address a system reliability concern on peak day
- Enbridge should treat this as a separate issue and take it to the Board if they choose.

7. EGD Peaking Contracts

- This should also be treated as a separate issue. If Enbridge is convinced that the current peaking service arrangements are underpinned by interruptible transportation, then they should address it.
- Maybe contracting for STFT to replace the peaking service arrangements is the action necessary to resolve the system reliability issue.

System Reliability Matrix Response (IGUA)

WORKING DRAFT - FOR DISCUSSION PURPOSES ONLY

EGD System Reliability Working Group

IGUA Comments

These comments/questions are offered for the purpose of discussion, and should not be taken to indicate final IGUA positions on the issues under consideration.

General comments:

In its EB-2008-0219 Phase 2 Decision, the Board expressly stated that it was comfortable that its interim solution (which requires ABC-T customers to demonstrate firm transportation for winter 2009/2010 in proportion to the average of their last 3 years of firm transportation as a percentage of total deliveries, plus 10%) would meet reliability requirements for this past winter. This comfort level was expressly premised on findings of a significant amount of non-firm contracted TCPL capacity and that EGD's franchise is not significantly transportation constrained. ***At first instance, for any incremental measures to be implemented, demonstration of some changes in circumstance since the time of that Board decision should be required.***

System Reliability Matrix Response (IGUA)

WORKING DRAFT - FOR DISCUSSION PURPOSES ONLY

- Assuming that there is a system reliability problem, and that a certain amount of transportation capacity must be firm, how can we determine how much capacity is required to be firm?
  - The starting point should be that EGD can rely on a customer meeting their MDV obligations. This assumption would dictate that all MDV obligations should be firm.
    - What is EGD's total MDV for bundled transportation customers, and is it currently 100% underpinned by firm transportation?
    - What is the MDV for Ontario Transportation customers?
  - Is there some basis upon which firming up less than the MDV volumes can be justified? What is that basis, and what is the resulting firm transportation requirement?
  - Would replacement of current design day criteria (39.5 dd) with historical peak day design criteria (43.9 dd) and/or the "firming up" of peaking supply arrangements alter the conclusion regarding how much of the MDV volumes must be firmed up, and if so what would the adjusted conclusion be?

System Reliability Matrix Response (IGUA)

WORKING DRAFT - FOR DISCUSSION PURPOSES ONLY

- Notionally, foregoing gas consumption should be equivalent to MDV gas delivery for the purposes of ensuring system reliability on a transportation capacity constrained day.
  - Is it feasible to allow larger customers to meet their "system reliability obligations" by agreeing to remote flow control in lieu of a requirement to demonstrate firm upstream transportation?
  - Ideally, such flow control would be initiated only to effect reduction in volume consumed equivalent to the volume shortfall on the customer's MDV. Is this level of control and operational reaction feasible?
- All options under consideration require cost by customer class information, for both Western T and Ontario T customers, and derived based on the firm volume requirements resolved to be appropriately applied.
- As a matter of principle, it is IGUA's view that any regulatory intervention should be structured so as to least impair the "natural" development of the Ontario/Eastern North American gas market. For example, a requirement to contract for, or take assignment of, long-term TCPL long haul contracts should be avoided, in the interests of preserving market response for new build short haul and sourcing of eastern North American gas supplies.

System Reliability Matrix Response (IGUA)

WORKING DRAFT - FOR DISCUSSION PURPOSES ONLY

- **Curtailment of firm customers** "option". IGUA views the "option" to be remote shut off capability (i.e. flow control meters). "Curtailment" is a level of distribution service already in place. EGD should be able to specify how much curtailment it can rely upon for peak day planning purposes (somewhere between 0% and 100% of the load under curtailable rates). This reliable curtailment volume should reduce any requirement for the curtailable customers, as a group, to firm up transportation. The assessment of how much curtailment can be relied on should contemplate the changes to curtailable service described by EGD at the April 8, 2010 meeting, including: i) demonstration of ability to accommodate total interruption of gas service; ii) disallowance of curtailment credit for the (entire) winter season for customers who fail to comply with a curtailment order; and iii) revision of unauthorized overrun charges to 150% of the highest price of gas in effect on the day.

System Reliability Matrix Response (IGUA)

WORKING DRAFT - FOR DISCUSSION PURPOSES ONLY

Option	Comments/Issues
Vertical Slice. EGD contracts firm for MDV for both system and DP customers (all customer segments). DP customers are assigned proportional capacity allocation, and can "optimize" (by utilizing pipeline service features such as diversions).	• EGD is required to contract at least cost to meet reliability requirements. Under current circumstances, this should dictate STFT for certain winter months (December through March, or some shorter period - DE suggests January and February, based on the last 56 years). If EGD becomes concerned about the availability of STFT, it should come back to the Board for authorization to change its contracting practices. • It may be appropriate for EGD to commit to longer term transportation contracts to underpin new build, for the benefit of the market as whole. Unless this is the least cost option, it should be subject to advance OEB approval. [IGUA considers this point to address Direct Energy's "Short Haul Build" option.] • Would customers be able to "opt out" of this mechanism upon demonstration of their own firm transportation arrangements? (Such demonstration by the customer would have to be sufficiently in advance of EGD's annual planning cycle.)

System Reliability Matrix Response (IGUA)

WORKING DRAFT - FOR DISCUSSION PURPOSES ONLY

Option	Comments/Issues
Vertical Slice. EGD contracts firm for MDV for both system and DP customers (all customer segments). DP customers are assigned proportional capacity allocation, and can "optimize" (by utilizing pipeline service features such as diversions).	• EGD to confirm additional transportation required to match all customers' MDVs, incremental cost, and proposed allocation of that cost to various rate groups (meaning rate classes, subdivided into system and DP customers, as the latter should presumably bear any incremental firm transportation cost). • Are there implementation timing issues related to the ability of DP customers to turn back their existing firm transportation to preclude excessive overall contracting? Would an "opt out" (partial or complete) option address this issue? • Turn back of new allocations would render this intervention ineffective and so could not be permitted. • The costs of implementing a vertical slice solution should be borne by all distribution customers (allocated as part of vertical slice mechanism), as an expenditure to facilitate continuation of a competitive Ontario gas services market. • For those customers with insufficient credit capacity to contract for firm transportation, the vertical slice might be preferable as it would provide a capacity assignment that could be optimized. What is the real value of this "optimization" potential to customers (marketers and large volume users)?

ENBRIDGE

System Reliability Matrix Response (IGUA)

WORKING DRAFT - FOR DISCUSSION PURPOSES ONLY

Option	Comments/Issues
"Interim Solution." The various positions to date are really sub-options differing in respect of the type and quantum of transportation capacity required. The basic framework is that the DP customer is responsible for firming up a specified portion of their MDV (rather than the utility assuming that responsibility under the "vertical slice" option).	• It should be up to Ontario T-service customers to determine how best to contract for firm transportation. In particular, STFT and/or alternative (new build) shipping contracts should be permitted. (The latter would only satisfy regulatory requirements as the new build is placed in service.) • Affected customers should be required to demonstrate firm transportation for the coming winter by November 1st. (What sanction should there be for failure to obtain sufficient firm transportation capacity?) • The OEB "interim solution" parameters (January through March) should be the starting point. Should this period be shifted to include December but exclude March, or changed include only January and February (as DE has suggested based on the last 56 years of data)? • Is there a basis for reducing the firm requirement below the customer's full MDV? • Those customers with insufficient credit capacity would need to become western T-service customers.

Appendix E

System Reliability Matrix Response (IGUA)

WORKING DRAFT - FOR DISCUSSION PURPOSES ONLY

Option	Comments/Issues
Backstopping service. In lieu of EGD contracting for firm transportation for all customers, or Ontario T service customer contracting obligations, EGD would provide a backstopping service. EGD would contract for firm short-notice transportation and storage.	•This could be a least cost option, overall, only to the extent that EGD could rely on "diversity" to mitigate risk of customer non-delivery. However, in a pipeline constrained peak day situation, it is not clear that diversity reliance would be appropriate. If diversity benefits do not reduce the amount of firm transportation required, this would seem to be a non-cost effective option. • Any costs of this service should be recovered fully from those customers for whom it is developed. • Would it be feasible to allow Ontario T customers who demonstrate firm transportation to opt out of cost responsibility for backstopping, and if so under what conditions (i.e. by when would this demonstration be required)?

System Reliability Matrix Response (IGUA)

WORKING DRAFT - FOR DISCUSSION PURPOSES ONLY

Option	Comments/Issues
Remote shut off. EGD would supply, and customers opting for participation in this program would pay for (capital and ongoing operating costs), remote control gas flow limiters. Indications are that relative to the cost of firm transportation on TCPL, the amortized capital and operating costs of these devices would be marginally less expensive.	• IGUA sees this as a customer electable alternative to a requirement to demonstrate firm upstream transportation, or to participate in a utility vertical slice program. Could this be implemented on a customer election basis? (Given the long equipment life, once a customer elects this option they would presumably be bound to stay with it for the duration of the life of the equipment, or at least to pay for the equipment in full.) • The option would only be attractive to large volume customers who are not concerned with business loss or equipment damage from short notice flow limitation. Preliminary indications from both EGD and IGUA polling of large volume customers is that a sizeable portion of this customer group might be interested in this option. • Validation of the costs of this option, relative to the customer costs of the alternative option ultimately proposed, will be required, following which a more definitive survey of eligible customers should precede any adoption of this option.

System Reliability Matrix Response (IGUA)

WORKING DRAFT - FOR DISCUSSION PURPOSES ONLY

Option	Comments/Issues
Firm delivery. Shell proposed this option as an alternative. As IGUA understands it, the credit rating of the supplier would be considered indicative of reliable fulfillment of an obligation to deliver gas to Ontario. According to Shell, the business costs of a failure to deliver would definitively outweigh cost to deliver, even on a peak day, and thus the supplier would pay whatever it had to pay to get gas to the franchise.	• The operating premise underlying this option is that a credit worthy supplier obligated to deliver will not consider the economics of obtaining marginal transportation capacity as a factor that could lead to a business decision not to deliver. In IGUA's view, this "option" is really premised upon acceptance that there is no reasonable likelihood of peak day transportation capacity physical constraint to the franchise. • IGUA does not consider this option as an alternative to address an accepted capacity physical constraint contingency.

System Reliability Matrix Response (IGUA)

WORKING DRAFT - FOR DISCUSSION PURPOSES ONLY

Option	Comments/Issues
Adjustment of Design Degree Day (DDD). EGD would adjust its DDD from 39.5 to its historical peak day experience of 43.8. EGD has also suggested adding wind effects to its DDD criteria.	• As IGUA understands it, the nexus between this issue and system reliability relates to increase in peak day delivery capacity required to be secured under a higher DDD criteria. Such an increase in peak day delivery capacity required could result in: –A greater amount of supply (perhaps underpinned by firm transportation, see below). –To the extent that less than 100% of customers' MDV is otherwise required to be firmed up, this criteria change might increase that percentage. (If more capacity is assumed to be required on a design day, and capacity is potentially constrained on a peak day, then the availability of discretionary capacity on a peak day would be even tighter as the peak requirement is larger.) –On the other hand, a more conservative planning assumption also means a lower probability of occurrence. While current DDD criteria has probability of occurrence of 20% (relatively high), using historical peak would reduce that probability to 5% (relatively low). This significantly lower probability of occurrence, if hedged by increased peaking supply underpinned by firm transportation, may lead to a reasonable conclusion that less than 100% of MDV volumes require firm transportation underpinning. –Subject to more complete consideration of conclusions in other jurisdictions on the issue, adding wind effects to DDD criteria seems to be a reasonable proposal. The impact of this change would be subject to the same considerations as outlined above in respect of increasing the DDD temperature level. –The costs of incremental peaking supply should be borne by all customers.

System Reliability Matrix Response (IGUA)

WORKING DRAFT - FOR DISCUSSION PURPOSES ONLY

Option	Comments/Issues
Firm Transportation Supported Peaking Contracts. EGD's current peaking supply is contracted on the basis of "firm delivery". Going forward, EGD would require its peaking suppliers to demonstrate firm upstream transportation.	• IGUA believes this to be a reasonable proposal. • As this would result in more firm transportation capacity to the franchise, everything else being equal it should also lessen concerns regarding the need to underpin MDV with firm transportation. • The costs of incremental peaking supply firm transportation should be borne by all customers.

Appendix F: Eastern Canadian Mutual Assistance Plan (ECMAP) UPDATED – Malini Giridhar

Eastern Canadian Mutual Assistance Plan (ECMAP)

ECMAP operates under the following guidelines:

- Level 1 condition is defined as a supply shortfall that can be managed by the member through curtailment, maximizing storage and peak shaving facility or facilities or obtaining gas from the marketplace. Level 1 condition is not eligible for assistance as part of the ECMAP.
- A Level 2 condition is defined as a situation that results from an unplanned facility outage that causes or will likely cause a supply shortfall to firm customers and cannot be managed under Level 1 conditions.
- ECMAP provides a process where all or individual members may voluntarily without any obligation whatsoever allocate available natural gas and transportation service to assist a member in a Level 2 condition.
- Duration of assistance is for a minimum of 1 day and not more than 5 days
- … under no circumstance will any member be required to contravene or breach its gas transportation tariff or any of its existing obligations including without limitation any firm and interruptible contracts with its shippers and obligations with any interconnecting pipeline.
- Maximum of five days or mutually agreed to period to pay back replacement gas. Affected member is responsible for all reasonable costs. If there is no payback, assisting member can purchase replacement volume and recover all reasonable costs.
- Members: City of Kitchener; City of Kingston; NrG; EGD, GMi, Union Gas, TCPL.

Eastern Canadian Mutual Assistance Plan (ECMAP) cont'd

- ECMAP agreement in place since 1995
- Increased focus on ECMAP in 1999 to address Y2K
- ECMAP has not been called on by EGD to date
- EGD considers ECMAP in emergency planning based on the following:
    1. Evaluate impact of outage on distribution system
    2. Institute curtailment of interruptible customers
    3. Investigate availability of gas supply in market place for incremental supply, as well as, initiate communications with ECMAP members for supply availability
    4. If incremental supply does not mitigate outage, declare force majeure and institute phased curtailment of firm customers

ENBRIDGE

Working Committee Notes

Enbridge Gas Distribution Inc.
Working Committee Meeting 6
On
System Reliability

May 17, 2010
Ontario Energy Board
2300 Yonge St., 25th Floor
West Hearing Room

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Putting the Pieces Together

Table of Contents

Enbridge Gas Distribution Inc.
Working Committee Meeting 6
On
System Reliability

1. Opening and Introductory Remarks

Presented by Bob Betts, Facilitator

The meeting was called to order at 9:00 AM.

Bob briefly provided the group with the background for the meeting and the agenda for the day.

He indicated that the first part of the morning would be spent in further discovery and following which the group would switch to something more similar to a settlement phase.

Bob indicated that before the committee entered the settlement phase that the committee would talk about how that part of the consultation should proceed.

He then invited Malini Giridhar to make the Enbridge presentation.

2. Action Items from Previous Meetings – M. Giridhar

Malini first briefly discussed the Action Item list from the previous meeting. She said that there were three items, two were updates to the presentation tables which were included in the Revised Notes from that meeting, and the third related to curtailment, and that was sent out independently by email.

Malini asked if there were any questions or comments on the Action Item list and there being none, she moved on to the presentation of the Enbridge proposal.

3. EGD System Reliability Proposal – Malini Giridhar

(Commencing with Slide 4 of the presentation contained in Appendix C)

Malini began by stating that Enbridge sees this proposal as a package even though components will be presented and discussed separately, changes to one will affect the others.

3.1. Mass Market Short Haul Assignment

Slide 4 outlined the details of this component of the Enbridge proposal.

- Mass Market retailers receive a temporary assignment of 50,000 GJ/d of short haul capacity from Dawn to EGD's CDA
- EGD replaces assignment with equivalent long haul STFT for five months (November to March) for sales customers
- Assignment criteria
  - Assignment available to all agents with MDV delivery obligations of 1500 GJ/d or more
  - Assignment ~30% of MDV obligation
  - Assignment reviewed prior to Nov 1 each year
- EGD would consider expanding this program based on future market dynamics.
  - May require implementation of technology (IT) based solution to allocate capacity to end use customer rather than to agent

In response to a question from IGUA, Malini explained that future market dynamics referred to changes in the availability of additional short haul capacity to the CDA, most likely resulting from new builds. If additional short haul became available there might be further assignment. Malini indicated that future changes to this assignment would probably also see the assignment being made to the customer rather than the sales agent so that the assigned volume would follow the customer. This would require Enbridge to implement a vertical slice methodology into their processes.

Shell asked about which classification of direct purchase customer type would be eligible for this assignment, Malini and Ian indicated that it is 'Agent" type only, (as defined in the Rate Handbook), and it would apply to Ontario-T only.

CME asked for clarification about the concept of expansion of this program, Enbridge indicated that this is for information only. Any expansion of this concept would be handled in another process.

IGUA asked another question about the 4th bullet point, specifically if that bullet suggests that this is not a long term resolution in Enbridge's view. Enbridge clarified by saying that they do consider this a long term resolution based upon what is known today. This point is only intended to confirm that if things change in the future, then further changes may be considered.

VECC asked about the details of the 50,000 GJ/d short haul. Malini explained that it is 1/3 of the total 150,000 GJ/d short haul capacity that Enbridge holds from Dawn to the CDA. It is firm capacity that is renewable every year.

Prepared by Regulatory Support Services (Div of R. J. Betts Enterprises Ltd.)

IMPACTS

As discussed later on slide 7, the impact of this component of the proposal was a total cost of $5.4 Million, or 0.0009 $/m3 for all Sales and Western T customers, rate classes 1, 6 and LV (large volume). The annual impact for rate 1 sales customers was shown as $3.00 per year.

3.2. Replace 200,000 GJ/d of Peaking Supplies with STFT for 3 months

- Represents ~75% of design day peaking requirements for 2009 & 2010
- STFT will be used in lieu of peaking supplies in peak and near peak conditions and will Enbridge to replace Dawn purchase requirements if applicable
  - Provides benefit to Sales and western-T customers, which will appear through the transportation charge.

IMPACTS

The impact of this component of the proposal, as outlined on slide 7 was a total cost of $17.8 Million, or 0.0019, 0.0017 and 0.0 $/m^3 for Sales customers, rate classes 1, 6 and LV respectively. The annual impact for rate 1 sales customers was shown as $6.00 per year.

The impact was 0.0026, 0.0024 and 0.0001 $/m^3 for direct purchase customers (Ontario-T), rate classes 1, 6 and LV respectively. The annual impact for rate 1 Ontario T customers was shown as $8.00 per year.

3.3. Acquire 80,000 GJ/d of STFT for Three Months to Provide a Reserve Margin

- Reserve margin is a concept used by many utilities and provides additional coverage in different scenarios such as:
  - one DD over current design day of 39.5 DD
  - higher than average wind conditions on current design day
  - failure to deliver (>300,000 GJ/d of direct shipper gas uses discretionary services)
- Benefits all customers through increased security of supply

IMPACTS

The impact of this component of the proposal, as outlined on slide 7 was a total cost of $11.5 million, or 0.0011, 0.0011 and 0.0011 $/m^3 for Sales customers, rate classes 1, 6 and LV respectively. The annual impact for rate 1 sales customers was shown as $3.00 per year.

VECC questioned the appropriateness of a Design Day methodology change of this type in relationship to the system reliability issue. Enbridge replied by saying that they were not trying to change the degree day methodology at this stage, but may contemplate that change during rebasing. This proposal of an added reserve margin was intended to address the capacity shortfall risks, which are often associated with cold weather conditions, but generally come from infrastructure problems.

VECC wasn't necessarily arguing against a change to the degree day methodology, indicating that most utilities now include a "wind" factor, but that this consultation process on system reliability was insufficient to underpin the required changes to the methodology.

Malini agreed with VECC's point, but stressed the "reserve" nature of the capacity saying that it would serve to cover off for slightly colder weather, slightly windier weather and some failure to deliver.

3.4. Rate Handbook & Contract Changes to LV Firm Service

Rate Handbook

- Large Volume customers obligated to deliver Mean Daily Volume during the months of December to March unless otherwise authorized by Enbridge,

  NOTE to READERS: During her oral presentation of this slide Malini corrected the obligation period to be from November to March, instead of December to March; all parties were asked to correct their copies.

  - Unless authorized, any shortfall in delivered volume will be treated as Unauthorized Overrun Volume

Contract Changes

- EGD will ensure contractual ability to suspend service to large volume customers who fail to deliver
  - Legal review in conjunction with review to address MDV re-establishment, HST etc

In response to a question from CCC, Enbridge indicated that they are not proposing at this time to install any form of remote curtailment devices and therefore, their ability to effectively shut down customers that fail to deliver and still continue to consume would probably be reduced to a very small number of large volume customers.

3.5. Increase Effectiveness of Curtailment

- Demonstrated ability to curtail or use backup fuel
- Penalties for failure to deliver/curtail during curtailment
  - o 150% of highest price on day applied to unauthorized volume
  - o Pull back of curtailment credits
  - o Transfer to firm service at EGD's sole discretion
- Elimination of 72 hour curtailment notice service under Rate 145

The 72 hour curtailment notice service no longer serves a purpose since the 3 day notice period cannot effectively address system reliability matters. Movement of this customer group to either 16 hour notice or firm transport will make curtailment volumes more dependable and transfer some of the associated curtailment credits to firm customers. Malini offered to add a clarifying note to this slide about this proposal regarding 72 hour curtailment notice service.

IGUA questioned whether this change would impact the amount of curtailment volume Enbridge plans on having, but Enbridge indicated that for peak day planning and from a system reliability perspective, they do not include any volume from this group and therefore there will be no change to the curtailment capacity volumes for planning purposes.

VECC asked if Union had a parallel situation with respect to this customer type. Enbridge indicated their understanding that Union uses curtailment for distribution system capacity issues only, while Enbridge uses curtailment for supply issues and as such the two approaches to curtailment are very different.

3.6. Changes to Turnback Policy

- EGD has offered turnback of TCPL FT capacity over the last decade
  - o Current Ontario - T assignments for Nov 1, 2010 ~30,000 GJ/d
  - o Current Western - T assignments for Nov 1, 2010 ~141,000 GJ/d
- A change to current Turnback Policy is required to ensure sustainable solution to system reliability concerns
- The Company will make reasonable efforts to accommodate TCPL FT capacity turnback requests, subject to the following considerations:
  - i. The FT capacity to be turned back must be replaced with alternative, contracted firm transportation (primary capacity or assignment) that Enbridge in its sole discretion considers to be of equivalent quality to the TCPL FT capacity;

ii. The amount of turnback capacity that Enbridge will accommodate may be reduced to address the impact of stranded costs, other transitional costs or incremental gas costs arising from any turnback request; and

iii. Enbridge must act in a manner that maintains the integrity and reliability of the gas distribution system and that respects the sanctity of contracts.

Malini added a comment about point ii) saying that the Turnback could result in adding transportation costs to all customers because of the reduction in Enbridge's ability to use TCPL Storage Transportation Service (STS). STS is a service that is a function of long haul FT and which Enbridge depends upon to meet winter demand by withdrawing gas from storage. A reduction in long haul FT would result in reduced injections in the summer.

CME expressed some concern about the first sub-bullet i) and the phrase "Enbridge in its sole discretion considers to be of equivalent quality to the TCPL FT capacity", saying that this may lead to unnecessary debate about suitable alternatives. Enbridge was sympathetic to that concern and indicated that the criteria changes frequently, but they could try to publish a list annually of the suitable alternative services as they see them.

CME indicated that it would be helped if Enbridge could list in an informal way as part of this settlement, the alternatives that would be considered suitable now, recognizing that this could change in the future. Alternatively, IGUA indicated their feeling that Enbridge should specify acceptable alternatives now, and be forced to go to the OEB for changes to the rate order in the future.

AEGENT asked if Enbridge was discussing the issue of STS with TCPL to see if modifications to the service were possible. Enbridge confirmed that some discussion had taken place and were continuing. TCPL added that some efforts had been made to make changes, but none have resolved Enbridge's problem yet.

Moving on to Slide 11, Enbridge indicated that 91% of Western T capacity is used for mass market customers and that they generally pay less than, or certainly no more than alternate Ontario T arrangements. Slide 11 showed an excerpt from Energyshop.com confirming those charges. Enbridge provided this information to make the point that suspension of turnback for mass market Western T customers is unlikely to increase their transportation costs

IGUA offered their assessment that what Enbridge was saying was that they could not support any further Turnback. IGUA asked Enbridge to think about that and come back with their clear position on whether or not Turnback should continue. After a question from Direct Energy, IGUA made the point more clearly saying that it doesn't seem evident that Turnback can continue until there are some other suitable supply routes into the CDA and EDA, in other words until additional short haul becomes available.

AEGENT and Shell felt that suppliers have alternate routes that they can provide now to replace Turnback from Empress. After some discussion, AEGENT and Shell indicated that they would make an initial listing of those alternative supply routes for Enbridge's consideration and the committee's information.

Malini moved on to the last two slides of the proposal presentation, slides 12 and 13, showing the System Reliability Matrix filled in with current information and highlighting how each of the 6 Proposal components addresses system reliability and competiveness. The slide also summarized Ratepayer/Shareholder costs and potential implementation timing.

In reviewing the slide 12, Malini caught an error on the implementation dates for Proposal Components 4 and 5. The date of Jan. 1, 2010 should be changed to read Jan. 1, 2011.

That concluded the presentation and final follow-up questions were invited.

In response to a question from IGUA, Enbridge confirmed that the $500,000 potential credit benefits associated with 72 hour curtailment was not included on the impact slide for mass market customers.

4. Settlement Phase

Bob Betts led a discussion about the Committee's preferred approach to the settlement or negotiating phase of this consultation process, indicating that he would play whatever role parties wished in order to see this communication process continue toward a full settlement.

All parties agreed to break for one hour, allowing intervenors the opportunity to meet alone to discuss issues in general and agree on a process for settlement negotiations.

Everyone agreed to break and return at 11:30 AM. Enbridge and the Facilitator left the room to allow Intervenors to have a discussion.

Break for Intervenor (Only) Discussion
10:30 AM

5. Plenary Settlement Session 1 – 11:30 AM

At 11:30 AM Enbridge was invited back into the room to received further questions and a brief update from Intervenors.

5.1. Responses to Morning Questions

Enbridge began by responding to questions asked in the morning, starting with slide 7 from the morning's presentation.

The slight difference between the impact to Large Volume customers versus rates 1 and 6 in the first row, the 50,000 GJ/d assignments, was correct and results from the allocation methodology.

Similarly, the Large Volume allocations for Replacing Peaking with STFT are correct and are a function of the allocation methodology.

VECC had asked about the cost of IT system upgrades to accommodate a vertical slice methodology if the first element was expanded. The capital costs are estimated to be $5 Million (annualized to $1 Million per year). This would represent an annualized impact for rate 1 customers of 50¢ per year.

Finally, Enbridge was able to confirm that the annual benefits potentially available from the removal of the 72 hour curtailment notice service were only about $100,000.

TCPL was now able to reply to IGUA's action item request for an update on Turnback this year. Lisa provided sheets that listed the capacity that was turned back and also the results of the Open Season to redistribute the turnback capacity.

This prompted a discussion about GMi allowing some turnback. While there was no certainty about how they replaced that turnback, IGUA and AEGENT indicated their understanding that they had contracted for firm delivery. IGUA felt that this was an indication of a change in GMi's traditional determination to have 100% firm transport.

That said, IGUA admitted that the situations are vastly different between GMi and Enbridge, with Enbridge's capacity exposure being much greater GMi's based on these turnback numbers.

5.2. Intervenor's Position of the Settlement Process

CME spoke for the intervenor members of the committee saying that they were communicating very well and preferred to proceed on their own, reconvening with Enbridge at strategic times. They felt that they would like to work through lunch and meet again with Enbridge at about 1:30 PM.

The Committee broke at 11:50 AM to reconvene after lunch.

Break for Intervenor (Only) Discussion
11:50 AM

6. Plenary Settlement Session 2 – 1:30 PM

At 1:30 PM Enbridge was invited back into the room to respond to further questions arising after the intervenor group had their initial review.

CME led the Q&A process first pointing Enbridge to slide 4.

6.1. Additional Intervenor Questions

Slide 4 – Component 1

Q-How often would the STFT assignment occur?

A- Once a year, on November 1st.

Q-Would large volume customers also be eligible for assignment if they meet the 1500 GJ/d criteria? Please explain why not.

Q-Intervenors need a written definition of what an Agent is.

Slide 5 –Component 2

Q-Would there be "optimization" benefits on this and Components 1 and 3, and where would those benefits flow to?

A- To the extent that the STFT could be used to displace Dawn purchases, that amount would flow through the PGVA.

Q- The benefits flow through the PGVA, what groups are attributed the costs?

A- The benefit and costs would flow to sales and Western T customers.

Q- What about optimization benefits from 1 or 3?

A- There are no expected no optimization benefits from 1 because it would be used as base load. Component 3 would probably have limited optimization benefits; it would be called upon for supply whenever the degree day exceeded a certain point.

Q- If there were optimization benefits from 3, where would they flow through?

A- Those benefits would flow through the Transactional Services account. .

Slide 7 – Customer Impacts

Q- Can Enbridge provide the working papers identifying the calculation of the Total Cost $5.4, $17.8 and $11.5 million, hopefully showing the underlying assumptions?

Q- Can Enbridge provide a written description of how and why the total costs would be allocated to specific rate classes?

Slide 8 – Rate Handbook Changes

Q- How does the bullet under Rate Handbook impact a large volume customer's ability to self-suspend? Is Enbridge's concern that they want to secure the delivery or do they just want to know if the customer is consuming or not? And if notice is the concern, how far in advance does Enbridge need to know?

Slide 10- Turnback

Q- Can Enbridge provide an explanation why their Turnback focus is now on both the CDA and EDA, when it was only the EDA on April 30th?

Q- Still outstanding is IGUA's question about whether Turnback is an option or whether Enbridge wants to discontinue the turnback option.

Intervenors acknowledge that Enbridge is still waiting for the list of alternatives to Turnback FT.

Slide 13- System reliability Matrix

Comment- On the row 5, "Increase Curtailment Effectiveness", the intervenor members suggested that Enbridge indicate that "Some parties feel that there is an impact on "Competitive market".

Follow-up Questions/Comments

Q Slide 7- IGUA asked for further clarification on why on row 2, Replace Peaking with STFT the allocation of costs to large volumes sales customers was different from LV direct purchase?

A- Enbridge explained that for sales customers the costs of firming up of peaking supplies is allocated on the basis of the peaking allocator and they enjoy a share of the benefits if the STFT can displace some Dawn purchases. In the case of LV sales customers both numbers are very small and effectively net out to zero. In the case of the direct purchase, they get the cost allocation, which again is very small, but they do not get any offsetting benefit from the displacement of Dawn purchases, thus netting out to a very small number, but something greater than zero.

Comments
It was pointed out that the headings for the first column on slide 7 is “Options” which is now incorrect based upon the current application of these items, they should be called “Components”.

A further discussion ensued regarding suitable alternatives to FT Turnback, and Enbridge indicated that an alternative would be assignment of FT from some liquid trading point. AEGENT asked Enbridge to provide a list of the points they felt were liquid trading points.

Enbridge indicated that they would return at about 2:30PM with the answers that were available at that time.

Break for Enbridge to Develop Responses to Questions 2:05 PM

7. Plenary Settlement Session 3 – 2:45 PM

At 2:45 PM Enbridge returned to respond to questions from the plenary session 2 and prior.

Malini Giridhar responded to the earlier questions.

Q-Would large volume customers also be eligible for assignment if they meet the 1500 GJ/d criteria? Please explain why not.

A- The assignment of the Dawn short haul responds to direct purchaser concerns that they are being forced to firm up their transportation, large volume customers have not been forced to do so.

Q-Intervenors need a written definition of what an Agent is.

A- Referring to the Master Services Agreement, which Ian said he would send out to the group, there are two descriptions of customer types: first, one which owns 50% of the accounts and the other, being the “Agent” where ownership is less than 50% of all of the contracting accounts. A choice made at this stage determines which group of agreements the contracting party will need to sign.

There remained some confusion about the definition of an “agent” and Enbridge indicated that it would provide a written definition for circulation to the committee.

Q-Would there be "optimization" benefits on this and Components 1 and 3, and where would those benefits flow to?

A – Adding to her previous answer, Malini indicated that this STFT is not assignable or divertible like FT, and is therefore less suitable for optimization. The displacement of Dawn purchases in excess of the forecast would be a credit to the PGVA. Any optimization through Transactional Services would flow to the Transactional Services Deferral Account

Q-Enbridge earlier spoke about some loss of optimization potential resulting from the assignment of some short haul from Dawn, has that been factored into the benefit analysis?

A – No, the effects are not in the impact analysis. They are hard to estimate and would vary from year to year.

There was some follow-up debate about whether this would represent a net reduction or increase in transportation costs because of the extent that reduced shorthaul costs, versus additional STFT for 5 months versus loss in transactional services revenue would offset each other. IGUA pointed out that the net impact is an increase in costs of $5M.

Q- Can Enbridge provide the working papers identifying the calculation of the Total Cost $5.4, $17.8 and $11.5 million, hopefully showing the underlying assumptions?

A – Enbridge distributed copies of the working papers (copies may be found in Appendix E) and Don Small spoke to the committee about them. Don indicated that this is based on the numbers provided in the April 2010 QRAM.

The first component was the Assignment of Dawn short haul. In this component, transportation costs increase by $9.1M due to the replacement of shorthaul with 5 months of STFT. The replacement of Dawn purchases with Empress supplies provides a benefit of 3.5M for a net cost increase of $5.4M Don reviewed the other two scenarios in a similar way referring to pages 2 and 3 of the spread sheets and leading to the other two total cost estimates of $17.8 and $11.5 million.

Q- Would the cost of the assignment be reduced if it was only replaced for three months instead of five?

A – Because the assigned short haul is linked to base load supply from Chicago, replacing it for only three months would leave two months base load supply requirements not replaced.

Q- Can Enbridge provide a written description of how and why the total costs would be allocated to specific rate classes?

A – Written response is still being prepared.

Q- How does the bullet under Rate Handbook impact a large volume customer's ability to self-suspend? Is Enbridge's concern that they want to secure the delivery or do they just want to know if the customer is consuming or not? And if notice is the concern, how far in advance does Enbridge need to know?

A – This issue is primarily a matter of providing dependable notice. First, notice of a customer's intent to self-suspend is important to permit planning for that reduction of deliveries, but it is equally critical that the customer then follow through and cease consumption or there is unaccounted for demand. Supply planning needs confidence in both actions.

A reasonable notice period would be at least 2 days. Enbridge's intent would be to not withhold approval unreasonably. In response to CME's question, Enbridge agreed that they would allow wording that says Enbridge will accept 2 days notice of self-suspension, but will include language referring to penalties if consumption is not suspended. Parties agreed that the Business Rules would be modified to clarify this position.

Enbridge did indicate that they must have some mechanism that provides confidence that the self-suspension will be directly linked to a cessation of consumption, rather than allowing customer to suspend deliveries just because the price is expected to be high or for some other similar reason. On this basis, the notice must include the customer's request to suspend deliveries and the customer's promise to not consume.

IGUA further recommended that if the customer continued to consume despite providing notice to not consume, that the rule should allow them to be charged overrun.

Enbridge said they would attempt to come up with some wording that would resolve this question.

Q- Can Enbridge provide an explanation why their Turnback focus is now on both the CDA and EDA, when it was only the EDA on April 30th?

A- In this presentation, Enbridge has looked at both Western and Ontario turnback and found the western to be a very large number, with a significant amount in the CDA. The Rate Handbook only talks about Ontario Turnback, but Enbridge has over time allowed some limited western turnback. Enbridge needs to know how customers will be replacing this capacity when they turnback their FT.

The focus on the EDA came because there was more assignment of Ontario T in the EDA than the CDA, but now that the concern includes Western turnback, the focus includes the CDA.

In response to a scenario proposed by AEGENT, Enbridge agreed that it would have no problem with a generator turning back Western T FT, while replacing it with FT from Dawn.

Enbridge agreed to change slide 13, row 5 to add the comment that “Some parties feel that there is an impact on “Competitive market”.

In response to AEGENT’s earlier question, Enbridge indicated that it would consider: Empress, Emerson and Dawn be liquid trading points, from their perspectives.

8. Next Steps

At this point the Intervenor members of the committee remained in the meeting room to continue their discussion and stated that they would not expect to be ready to meet again prior to the scheduled meeting at 9:00 AM tomorrow morning.

The meeting adjourned at 3:45 PM to be reconvened at 9:00 AM May 18, 2010.

ADJOURN

Appendices

Appendix A: Meeting Agenda May 17, 2010

STAKEHOLDER CONFERENCE

Monday, May 17, 2010
9:00 AM – 4:00 PM
Ontario Energy Board
2300 Yonge St., 25th Floor
West Hearing Room

System Reliability

AGENDA

9:00 - 9:10 am	**Opening Remarks -** Bob Betts, Facilitator ▪ Welcome and Housekeeping Items ▪ Objectives and plan for this meeting
9:10 – 11:00 am	**EGD System Reliability Presentation -** M. Giridhar/K. Irani ▪ Action items ▪ Discussion re: EGD Proposal
11:00 – 12:00	**Settlement Discussions**
12:00 – 1:00 pm	**LUNCH**
1:00 - 4:00	**Settlement Discussions**

Appendix B: Participant Listing

Stakeholders

Attendee	Organization
Frank Brennan	AEGENT
Julie Girvan	CCC
Vince DeRose	CME
Ric Forster	Direct Energy
Brad Jenzen	Direct energy
Ian Mondrow	IGUA
Colin Schuch	Ontario Energy Board
Paul Dumaresq	Shell Energy
Murray Ross	TCPL
Lisa DeAbreu	TCPL
Roger Higgin	VECC

Enbridge Representatives

Attendee	Position
Malini Giridhar	Director, Energy Supply & Policy
Norm Ryckman	Director, Regulatory Affairs
Keith Irani	Manager, Energy Supply Services
Robert Bourke	Manager, Regulatory Proceedings
Ian Macpherson	Manager, Direct Purchase
Don Small	Manager, Gas Costs & Budgets
Edith Chin	Manager Upstream Regulatory Strategy &Major Projects
Fred Cass	Aird & Berlis (Counsel for Enbridge)

Other

Bob Betts	Facilitator, Regulatory Support Services

Appendix C: EGD System Reliability Proposal – M. Giridhar

ENBRIDGE

System Reliability Working Committee

May 17, 2010

System Reliability Working Committee Opening Remarks – Bob Betts, Facilitator

- Welcome & Housekeeping Items
- Objectives and Plan for the Meeting
  - Action items
  - System Reliability Proposal
- May 27 - Stakeholder Settlement Conference

EGD System Reliability Proposal

M. Giridhar

ENBRIDGE

1. Mass Market Short Haul Assignment

- Mass Market retailers receive a temporary assignment of 50,000 GJ/d of short haul capacity to CDA from EGD

- EGD replaces assignment with equivalent long haul STFT for five months for sales customers

- Assignment criteria
  - Assignment available to all agents with MDV delivery obligations of 1500 GJ/d or more
  - Assignment ~30% of MDV obligation
  - Assignment reviewed prior to Nov 1 each year

- EGD to consider expanding this program based on future market dynamics
  - May require implementation of technology (IT) based solution to allocate capacity to end use customer rather than to agent

2. Replace 200,000 GJ/d of Peaking Supplies with STFT for 3 Months

- Represents ~75% of design day peaking requirements for 2009 & 2010

- STFT will be used in lieu of peaking supplies in peak and near peak conditions and will replace Dawn purchase requirements if applicable
  - Provides benefit to Sales and western-T customers.

3. Acquire 80,000 GJ/d of STFT for Three Months to Provide a Reserve Margin

- Reserve margin provides coverage in different scenarios such as:
  - one DD over current design day of 39.5 DD
  - higher than average wind conditions on current design day
  - failure to deliver (>300,000 GJ/d of direct shipper gas uses discretionary services)

- Benefits all customers through increased security of supply

EGD Proposal - Customer Impact

			Rate 1		Rate 6	Large Volume
Option	**Firm Capacity (GJ/d)**	***Total Cost ($/M)***	**Impact *($/m³)***	**Annual Bill $**	**Impact *($/m³)***	**Impact *($/m³)***
Assign SH capacity and contract STFT *Sales and Western T*	**50,000**	**5.4**	**0.0009**	**$3.00**	**0.0009**	**0.0010**
Replace Peaking with STFT	**200,000**	**17.8**	**Sales** 0.0019 **Others** 0.0026	**Sales** $6.00 **Others** $8.00	**Sales** 0.0017 **Others** 0.0024	**Sales** 0.00 **Others** 0.0001
Reserve Margin *All customers*	**80,000**	**11.5**	**0.0011**	**$3.00**	**0.0011**	**0.0011**

Note: Assumes current TCPL tolls. TCPL's toll proposal for 2011 would result in a reduction in cost by ~20%. Also, the analysis reflects current basis spreads between Aeco, Chicago and Dawn which are at historical lows. A higher basis would also lower toll impacts, due to the displacement of Dawn and Chicago with AECO purchases.

4. Rate Handbook & Contract Changes to LV Firm Service

Rate Handbook

- Large Volume customers obligated to deliver Mean Daily Volume during the months of December to March unless otherwise authorized by Enbridge
  - *Unless authorized, any shortfall in delivered volume will be treated as Unauthorized Overrun Volume*

Contract Changes

- EGD will ensure contractual ability to suspend service to large volume customers who fail to deliver
  - Legal review in conjunction with review to address MDV re-establishment, HST etc

5. Increase Effectiveness of Curtailment

- Demonstrated ability to curtail or use backup fuel
- Penalties for failure to deliver/curtail during curtailment
  - 150% of highest price on day applied to unauthorized volume
  - Pull back of curtailment credits
  - Transfer to firm service at EGD's sole discretion
- Elimination of 72 hour curtailment notice service under Rate 145

6. Changes to Turnback Policy

- EGD has offered turnback of TCPL FT capacity over the last decade*
  - Current Ontario - T assignments for Nov 1, 2010 ~30,000 GJ/d
  - Current Western - T assignments for Nov 1, 2010 ~141,000 GJ/d
- A change to current Turnback Policy** is required to ensure sustainable solution to system reliability concerns
- The Company will make reasonable efforts to accommodate TCPL FT capacity turnback requests, subject to the following considerations:

  i. The FT capacity to be turned back must be replaced with alternative, contracted firm transportation (primary capacity or assignment) that Enbridge in its sole discretion considers to be of equivalent quality to the TCPL FT capacity;

  ii. The amount of turnback capacity that Enbridge will accommodate may be reduced to address the impact of stranded costs, other transitional costs or incremental gas costs arising from any turnback request; and

  iii. Enbridge must act in a manner that maintains the integrity and reliability of the gas distribution system and that respects the sanctity of contracts.

*Except in 2008 contract year
** Rider A Transportation Service Rider EGD Rate Handbook

Turnback and Western-T arrangements

- 91% of Western-T capacity is held on behalf of mass market customers.
- Mass Market Customers on Western-T typically pay less than or no more than Ontario-T arrangements.

<u>Excerpt from Energyshop.com*</u>

As of Jan 1, 2010, Transportation is separate from Delivery on the bill. Transportation is provided either by Enbridge, or by your gas marketer, depending on the terms of your gas marketer agreement. Some marketers charge a different rate for transportation than the variable charge from Enbridge (currently at 4.66 ¢/M3), depending on the details of their contract with specific customers. RiteRate and MyRate, will only charge the Enbridge variable rate. The information we have to date on other marketers is that when it is charged, these rates will apply. Active - 6.9 fixed. Direct - 5.46 variable. Firefly - 6.5 fixed. Just Energy - 6.79 variable. Superior - 6.9 variable.

* Transportation Note as of: May 12, 2010, Source: www.energyshop.com

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System Reliability Matrix

Impact of Proposal	System Reliability			Competitiveness	Ratepayer/ Stakeholder Costs	Implementation
	Firm Transport	**Incremental Supply (backstopping)**	**Load Reduction**	**Impact on Competitive Market**	**Ratepayer & Stakeholder Costs**	**Implementation**
1. Dawn-CDA Short Haul FT Capacity - Assign 50,000 Gj/d SH FT to Mass Market - EGD contracts STFT 5 months	Positive			Positive	Borne by Sales and Western T customers. Mass market direct purchase customers benefit	Nov 1 2010
2. Peaking replacement (partial) Replace 200,000 of peaking with STFT for 3 mths	Positive				Heat sensitive sales and direct purchase customers. Partial offset for sales customers	Nov 1 2010
3. Reserve Margin Acquire 80,000 GJ/d STFT for 3 mths	Positive	Positive			All customers	Nov 1 2010

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System Reliability Matrix

Impact of Proposal	System Reliability			Competitiveness	Ratepayer/ Stakeholder Costs	Implementation
	Firm Transport	Incremental Supply (backstopping)	Load Reduction	Impact on Competitive Market	Ratepayer & Stakeholder Costs	Implementation
4. Contract changes to LV Firm Service			Positive			Jan 1, 2010 or earlier
5. Increase Curtailment Effectiveness			Positive			Jan 1, 2010 or earlier
6. Turnback Policy Changes	Positive					April 2011

Appendix D: TCPL Turnback Results – Lisa DeAbreu

CANADIAN MAINLINE
NON-RENEWED EXISTING CAPACITY OPEN SEASON
May 7 - 14, 2010

TransCanada
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TransCanada's Canadian Mainline is currently posting the following firm transportation services in this Existing Capacity Open Season to make available the capacity due to non-renewals on April 30, 2010. Service on these paths will commence on or after November 1, 2010.

TransCanada will be accepting bids in this Existing Capacity Open Season for firm service until 8:00 a.m. Calgary time on May 14, 2010. The capacity available is located below in Table 1.

Table 1: Available Capacity[1]

Posted System Segments for FT	Capacity Starting November 1, 2010 (GJ/d)
Empress to (Domestic)	
South Saskatchewan Delivery Area (SSDA)	565,066
Manitoba Delivery Area (MDA)	565,066
Western Delivery Area (WDA)	375,562
Northern Delivery Area (NDA)	375,562
North Bay Junction	375,562
Central Delivery Area (CDA)	375,562
Eastern Delivery Area (EDA)[2]	331,365
Eastern Delivery Area (GMi EDA)	144,149
Southwest Delivery Area (SWDA)	144,861
Empress to (Export)	
Emerson	11,032
Kirkwall	129,035
Niagara	113,033
Chippawa	59,685
Iroquois	103,124
Philipsburg	301
East Hereford[3]	92,995

(1) TransCanada is not accepting bids for firm service with a receipt point of Iroquois at this time and TransCanada is evaluating its ability to offer additional FT service from all eastern interconnecting pipelines.
(2) Capacity available to Enbridge EDA, Union EDA, and Cornwall only.
(3) Shippers and prospective shippers should be aware that TransCanada has posted firm capacity to East Hereford that is in excess of the downstream firm take-away capacity on PNGTS. PNGTS may have interruptible capacity available on certain days, depending on operating conditions. When insufficient interruptible take-away capacity is available on PNGTS, those FT shippers on TransCanada that are unable to flow their gas downstream of East Hereford may instead nominate diversions to alternate Delivery Points or, if applicable, obtain FT-RAM credits for use elsewhere on the TransCanada system.

Table 1: Available Capacity Continued[1]

Posted System Segments for FT	Capacity Starting November 1, 2010 (GJ/d)
Shorthaul Transportation	
North Bay Junction to	
Central Delivery Area (CDA)	375,562
Eastern Delivery Area (EDA)[2]	331,365
Eastern Delivery Area (GMi EDA)	144,149
Southwest Delivery Area (SWDA)	144,861
Kirkwall	129,035
Niagara	113,033
Chippawa	59,685
Iroquois	103,124
Philipsburg	301
East Hereford[3]	92,995
Kirkwall to	
Niagara	113,033
Chippawa	59,685
St. Clair to	
St. Clair to Union SWDA	116,002
Union Dawn to	
Kirkwall	129,035
Niagara	113,033
Chippawa	59,685

(1) TransCanada is not accepting bids for firm service with a receipt point of Iroquois at this time and TransCanada is evaluating its ability to offer additional FT service from all eastern interconnecting pipelines.
(2) Capacity available to Enbridge EDA, Union EDA, and Cornwall only.
(3) Shippers and prospective shippers should be aware that TransCanada has posted firm capacity to East Hereford that is in excess of the downstream firm take-away capacity on PNGTS. PNGTS may have interruptible capacity available on certain days, depending on operating conditions. When insufficient interruptible take-away capacity is available on PNGTS, those FT shippers on TransCanada that are unable to flow their gas downstream of East Hereford may instead nominate diversions to alternate Delivery Points or, if applicable, obtain FT-RAM credits for use elsewhere on the TransCanada system.

OPEN SEASON & BIDDING PROCEDURE HIGHLIGHTS

- Bids must be received by TransCanada no later than 8:00 a.m. Calgary time on May 14, 2010
- Term: Minimum one (1) year term for the posted Firm Transportation service. Bids with a term of one year or greater shall be in full month increments
- Toll: The posted capacity will be at the approved NEB Approved Mainline Tolls
- System Segment Capacity:
    - Some posted segments share common capacity. A successful bid on one system segment may

reduce the capacity on another system segment. Any bids that pertain to common capacity will be evaluated together for allocation purposes
    - Each capacity segment requested must be on an individual bid form
- Conditional Bidding: Mainline capacity bids can be conditioned on another Mainline capacity bid
    - If an ECOS bid is conditional on another ECOS bid, if either ECOS bid requires a reduction to the maximum daily quantity, the maximum daily quantity for the other ECOS bid will be reduced by the same percentage.
    - Please submit each set of conditional bids in a separate fax, to provide clarity on which bids are related.
- Min Acceptable Quantity: May be specified by bidder in the event that prorating capacity is necessary
- Please refer to the TAPs: Transportation Access Procedures for more information

HOW TO BID
Service applicants must submit a binding bid via the Paper Version or Electronic Version to TransCanada's Mainline Contracting Department at (403) 920-2343 and must be received by 8:00 a.m. Calgary time on May 14, 2010. All bids received will be evaluated together for allocation purposes and notification will be provided within two (2) banking days to successful Service Applicants. When financial assurances have been provided to TransCanada, as outlined in TAPs, TransCanada will provide a contract to the Service Applicant, at which time Service Applicant will have 10 banking days to execute and return the signed contract to TransCanada.

OPEN SEASON DEPOSIT INFORMATION & PROCEDURE:

Successful bidders who currently hold a contract with TransCanada are not required to provide a deposit with each bid, although failure to comply with awarded capacity will result in a penalty charged by TransCanada to the account. Successful bidders who do not currently hold a contract with TransCanada shall be required to provide a deposit, within two (2) banking days of the close of the Open Season, with each bid provided to TransCanada, equal to lesser of:

- One (1) month demand charges for the maximum capacity set out on the Bid Form, calculated based on the tolls in place when the Bid Form was submitted; or
- $10,000 (Cdn)

The deposit can be provided by either wire transfer or cheque. Please contact your Mainline Sales Representative to obtain the TransCanada Bank Account information for wire transfers or to obtain the address for mailing cheques

QUESTIONS

If you have any questions about this Existing Capacity Open Season or any other, please contact your Mainline Sales & Marketing representative.

Calgary	Toronto
Gordon Betts (403) 920-6834	Amelia Cheung (416) 869-2115
Michael Mazier (403) 920-2651	Lisa DeAbreu (416) 869-2171
	Reena Mistry (416) 869-2159

Completed bids must be faxed by 8:00 a.m. Calgary time on May 17, 2010 to:

Mainline Contracting @ (403) 920-2343

TransCanada
In business to deliver

APPENDIX

LINKS to Additional Information:

- Existing Capacity Open Season Bid Form (Paper Version)
- Existing Capacity Open Season Bid Form (Electronic Version)
- Mainline Tariffs: Toll Schedules & Pro Forma Contracts
- TAPs: Transportation Access Procedure
- NEB Approved Mainline Tolls – January 1, 2010
- Index of Customers showing recent contracts and renewals
- Other TransCanada Information: **www.transcanada.com/Customer_Express**

GST Procedures for FT, FT-SN, STS, STS-L – FOR EXPORT POINTS ONLY

Pursuant to the Excise Tax Act, Canadian natural gas transporters are required to invoice the Goods and Services Tax (GST) on all services. GST on transportation charges for gas that is consumed in Canada is set at 5%. GST on transportation charges for gas that is consumed in the United States may qualify for zero-rating (0% GST).

For gas that is transported to export points for consumption in the United States, shippers may zero-rate GST on the associated transportation demand, commodity and pressure charges by making a Declaration on the nomination line in NrG Highway.

Shippers may also zero-rate GST on Unutilized Demand Charges (UDC) under firm contracts that have an export point as the primary delivery point in the contract. Note that UDC may only be zero-rated if the firm contract is intended for transportation of gas to, and consumption of gas in, the United States. UDC zero-rating for eligible firm contracts can be obtained by providing TransCanada with an executed Contract Declaration. A *proforma* Contract Declaration Form is available at the following link:

FT GST Declaration

Some key points to note regarding Contract Declarations to zero-rate GST on UDC under firm export Contracts:

- Contract Declarations may only take effect on the first day of a month.
- A Contract Declaration cannot be applied retroactively.
- A single Contract Declaration form is used for all of a shipper's firm export contracts eligible for zero-rating of UDC.

Please keep in mind that, even if 5% GST is applied on your transportation invoice, businesses will typically be eligible for rebates of GST from the Canadian Revenue Agency (CRA). Please refer to the following website for additional information on GST regulations and rebates:

http://www.cra-arc.gc.ca/tax/business/topics/gst/corporation/menu-e.html

For more information on TransCanada's GST practices, please contact Vincent Thebault at 403-920-5840 or vincent_thebault@transcanada.com.

Mainline Firm Contract Renewals for November 1, 2010

A total of **2,693** TJ/d of service under Mainline firm transportation contracts was scheduled for expiry on November 1, 2010. As of May 1, 2010, TransCanada received notice from Shippers to renew **1,856** TJ/d or **69 %** of the contract quantity scheduled to expire. Note that these contract quantities include firm service classes FT and STS for all paths (Long-haul and Short-haul).

Additional details on renewals by path and zone category are set out in the following table.

If you require clarification or further information, please contact:

Norma Marchet, Contracts Analyst at (403) 920-6258 or
Barbara Miles, Manager Contracts & Billing at (403) 920-5780

MAINLINE RENEWALS EFFECTIVE May 1, 2010					
Path Type	**Zone**	**Eligible**	**Renewed**	**Non Renewed**	**Percentage Renewed**
Eastern Short Haul	Chippawa	205,805	146,120	59,685	71.00%
	Cornwall	10,300	10,300	-	100.00%
	East Hereford	73,887	-	73,887	0.00%
	Eastern	966,688	946,688	20,000	97.93%
	Philipsburg	-	-	-	0.00%
	Southwest	105,275	5,275	100,000	5.01%
	Subtotal	**1,361,955**	**1,108,383**	**253,572**	**81.38%**
Long Haul	Chippawa	10,593	10,593	-	100.00%
	Cornwall	13,570	13,495	75	99.45%
	East Hereford	19,108	-	19,108	0.00%
	Eastern	732,736	539,382	193,354	73.61%
	Iroquois	110,329	7,205	103,124	6.53%
	Napierville	8,580	8,580	-	100.00%
	Niagara Falls	113,033	-	113,033	0.00%
	North Bay Junction	-	-	-	0.00%
	Northern	29,524	16,327	13,197	55.30%
	NCDA	1,545	1,545	-	100.00%
	Philipsburg	2,306	2,005	301	86.95%
	Southwest	31,828	-	31,828	0.00%
	SSMDA	-	-	-	0.00%
	Western	-	-	-	0.00%
	Subtotal	**1,073,152**	**599,132**	**474,020**	**55.83%**
Western Short Haul	Emerson 1	-	-	-	0.00%
	Emerson 2	11,032	-	11,032	0.00%
	Manitoba	225,657	146,443	79,214	64.90%
	Saskatchewan	21,450	2,200	19,250	10.26%
	Subtotal	**258,139**	**148,643**	**109,496**	**57.58%**
Grand Total		**2,693,246**	**1,856,158**	**837,088**	**68.92%**

Quantities are Contract Demand in GJ/d. Data is as of May 3, 2010 at 0800h MDT. Western: Delivery west of station 41, to MDA, or to Emerson; Longhaul: Primary Receipt west of 41 or at Emerson and Delivery east of 41 and Emerson; Eastern: completely east of station 41 or Emerson.

Appendix E: EGD Working Papers for the Total Cost Calculations – Don Small

Scenario # 1 -
50,000/day STFT
Nov to Mar
replaces Dawn to
CDA Shorthaul

Summary of Gas Cost to Operations
as per April 1, 2010 QRAM

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $\$/10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)	Col. 5 10^3m^3	Col. 6 $(000)	Col. 7 10^3m^3	Col. 8 $(000)	Col. 9 $\$/10^3m^3$ (Col.8 / Col.7)
	Western Canadian Supplies									
1.1	Alberta Production	0.0	0.0	0.000	0.000					
1.2	Western - @ Empress - TCPL	484,213.3	97,007.8	200.341	5.315	200,318.4	41,747.1	684,531.7	138,754.9	202.700
1.3	Western - @ Nova - TCPL	768,381.9	155,950.0	202.959	5.385			768,381.9	155,950.0	202.959
1.4	Western Buy/Sell - with Fuel	2,072.4	439.8	212.222	5.631			2,072.4	439.8	212.222
1.5	Western - @ Alliance	968,895.5	221,285.0	228.389	6.060			968,895.5	221,285.0	228.389
1.6	Less TCPL Fuel Requirement	(47,911.2)	0.0					(47,911.2)	0.0	-
1.	Total Western Canadian Supplies	2,175,651.9	474,682.6	218.179	5.789	200,318.4	41,747.1	2,375,970.3	516,429.7	217.355
	Short Term Supplies									
2.	Peaking/Seasonal	26,740.0	11,054.1	413.393	10.968			26,740.0	11,054.1	413.393
3.	Ontario Production	1,460.1	377.7	258.672	6.863			1,460.1	377.7	258.672
	Chicago Supplies									
4.1	Vector 1st Tranche	11,975.5	2,525.3	210.876	5.595			11,975.5	2,525.3	210.876
4.2	Vector 2nd Tranche	807,280.4	179,191.4	221.969	5.889			807,280.4	179,191.4	221.969
4.3	Vector 3rd Tranche	1,379,159.4	305,212.8	221.304	5.872			1,379,159.4	305,212.8	221.304
4.	Total Chicago Supplies	2,198,415.3	486,929.6	221.491	5.877			2,198,415.3	486,929.6	221.491
	Delivered Supplies									
5.	Ontario Delivered	1,071,636.5	245,600.1	229.182	6.081	(200,318.4)	(45,504.1)	871,318.1	200,096.0	229.648
6.	Total Supply Costs	5,473,903.7	1,218,644.2	222.628	5.907	-	(3,757.0)	5,473,903.7	1,214,887.2	221.942
	Transportation Costs									
7.1	TCPL - FT - Demand		70,957.3						70,957.3	
7.2	- FT - Commodity	1,206,756.4	3,071.4	2.545	0.068				3,071.4	
	TCPL - STFT - Demand		0.0				11,942.7		11,942.7	
	- STFT - Commodity	0.0	0.0			200,318.4	509.9		509.9	
7.3	Capacity Discounts		0.0						-	
7.4	- STS - CDA		4,011.4						4,011.4	
7.5	- STS - EDA		2,996.7						2,996.7	
7.6	- Dawn to CDA Exchange		10,173.1				(3,280.2)		6,892.9	
7.7	- Dawn to EDA Exchange		16,308.9						16,308.9	
7.8	Union C1 Transportation		0.0						-	
7.9	Nova Transmission		2,151.9						2,151.9	
7.10	ANR/Michcon Transportation		0.0						-	
7.11	Link Pipeline		0.0						-	
7.12	Alliance Pipeline		40,615.4						40,615.4	
7.13	Vector Pipeline - 1st Tranche		8,753.3						8,753.3	
7.14	Vector Pipeline - 2nd Tranche		7,204.2						7,204.2	
7.15	Vector Pipeline - 3rd Tranche		12,947.6						12,947.6	
7.	Total Transportation Costs		179,191.2				9,172.4		188,363.6	
8.	Total Before PGVA Adjustment	5,473,903.7	1,397,835.3	255.364	6.775	0.0	5,415.4	5,473,903.7	1,403,250.7	256.353

Item #		Scenario # 2 - 200,000/day STFT Jan to Mar replaces Peaking					Scenario # 2 b) 100% LF on STFT - UDC on Vector				
		Col. 10 10^3m^3	Col. 11 $(000)	Col. 12 10^3m^3	Col. 13 $(000)	Col. 14 $/$10^3m^3$ (Col.8 / Col.7)	Col. 15 10^3m^3	Col. 16 $(000)	Col. 17 10^3m^3	Col. 18 $(000)	Col. 19 $/$10^3m^3$ (Col.8 / Col.7)
	Western Canadian Supplies										
1.1	Alberta Production										
1.2	Western - @ Empress - TCPL	376,091.6	78,378.9	1,060,623.3	217,133.8	204.723	101,488.7	21,150.6	1,162,112.0	238,284.4	205.044
1.3	Western - @ Nova - TCPL			768,381.9	155,950.0	202.959			768,381.9	155,950.0	202.959
1.4	Western Buy/Sell - with Fuel			2,072.4	439.8	212.222			2,072.4	439.8	212.222
1.5	Western - @ Alliance			968,895.5	221,285.0	228.389			968,895.5	221,285.0	228.389
1.6	Less TCPL Fuel Requirement			(47,911.2)	-	-			(47,911.2)	-	-
1.	Total Western Canadian Supplies	376,091.6	78,378.9	2,752,061.9	594,808.6	216.132	101,488.7	21,150.6	2,853,550.5	615,959.3	215.9
	Short Term Supplies										
2.	Peaking/Seasonal	(26,740.0)	(9,744.7)	-	1,309.4	#DIV/0!	-	-	-	1,309.4	#DIV/0!
3.	Ontario Production			1,460.1	377.7	258.672			1,460.1	377.7	258.672
	Chicago Supplies										
4.1	Vector 1st Tranche			11,975.5	2,525.3	210.876			11,975.5	2,525.3	210.876
4.2	Vector 2nd Tranche			807,280.4	179,191.4	221.969			807,280.4	179,191.4	221.969
4.3	Vector 3rd Tranche			1,379,159.4	305,212.8	221.304	(101,488.7)	(22,460.0)	1,277,670.7	282,752.8	221.303
4.	Total Chicago Supplies			2,198,415.3	486,929.6	221.491	(101,488.7)	(22,460.0)	2,096,926.6	464,469.5	221.500
	Delivered Supplies										
5.	Ontario Delivered	(349,351.6)	(79,358.3)	521,966.5	120,737.7	231.313	-	-	521,966.5	120,737.7	231.313
6.	Total Supply Costs	-	(10,724.1)	5,473,903.7	1,204,163.0	219.983	-	(1,309.4)	5,473,903.7	1,202,853.6	219.743
	Transportation Costs										
7.1	TCPL - FT - Demand				70,957.3					70,957.3	
7.2	- FT - Commodity				3,071.4					3,071.4	
	TCPL - STFT - Demand		28,662.6		40,605.3			-		40,605.3	
	- STFT - Commodity	376,091.6	957.2		1,467.1		101,488.7	258.3		1,725.4	
7.3	Capacity Discounts				-					-	
7.4	- STS - CDA				4,011.4					4,011.4	
7.5	- STS - EDA				2,996.7					2,996.7	
7.6	- Dawn to CDA Exchange		-		6,892.9			-		6,892.9	
7.7	- Dawn to EDA Exchange				16,308.9					16,308.9	
7.8	Union C1 Transportation				-					-	
7.9	Nova Transmission				2,151.9					2,151.9	
7.10	ANR/Michcon Transportation				-					-	
7.11	Link Pipeline				-					-	
7.12	Alliance Pipeline				40,615.4					40,615.4	
7.13	Vector Pipeline - 1st Tranche				8,753.3					8,753.3	
7.14	Vector Pipeline - 2nd Tranche				7,204.2					7,204.2	
7.15	Vector Pipeline - 3rd Tranche				12,947.6					12,947.6	
7.	Total Transportation Costs		29,619.8		217,983.4			258.3		218,241.7	
8.	Total Before PGVA Adjustment	0.0	18,895.6	5,473,903.7	1,422,146.4	259.805	0.0	(1,051.1)	5,473,903.7	1,421,095.3	259.613

Scenario # 3
80,000 STFT - 3 months
Backstopping

Item #		Col. 15 10^3m^3	Col. 16 $(000)	Col. 17 10^3m^3	Col. 18 $(000)	Col. 19 $/$10^3m^3$ (Col.8 / Col.7)
	Western Canadian Supplies					
1.1	Alberta Production					
1.2	Western - @ Empress - TCPL	-	-	1,162,112.0	238,284.4	205.044
1.3	Western - @ Nova - TCPL			768,381.9	155,950.0	202.959
1.4	Western Buy/Sell - with Fuel			2,072.4	439.8	212.222
1.5	Western - @ Alliance			968,895.5	221,285.0	228.389
1.6	Less TCPL Fuel Requirement			(47,911.2)	-	-
1.	Total Western Canadian Supplies	-	-	2,853,550.5	615,959.3	215.9
	Short Term Supplies					
2.	Peaking/Seasonal	-	-	-	1,309.4	#DIV/0!
3.	Ontario Production			1,460.1	377.7	258.672
	Chicago Supplies					
4.1	Vector 1st Tranche			11,975.5	2,525.3	210.876
4.2	Vector 2nd Tranche			807,280.4	179,191.4	221.969
4.3	Vector 3rd Tranche	-	-	1,277,670.7	282,752.8	221.303
4.	Total Chicago Supplies	-	-	2,096,926.6	464,469.5	221.500
	Delivered Supplies					
5.	Ontario Delivered	-	-	521,966.5	120,737.7	231.313
6.	Total Supply Costs	-	-	5,473,903.7	1,202,853.6	219.743
	Transportation Costs					
7.1	TCPL - FT - Demand				70,957.3	
7.2	- FT - Commodity				3,071.4	
	TCPL - STFT - Demand		11,465.0		52,070.3	
	- STFT - Commodity	0.0	-		1,725.4	
7.3	Capacity Discounts				-	
7.4	- STS - CDA				4,011.4	
7.5	- STS - EDA				2,996.7	
7.6	- Dawn to CDA Exchange		-		6,892.9	
7.7	- Dawn to EDA Exchange				16,308.9	
7.8	Union C1 Transportation				-	
7.9	Nova Transmission				2,151.9	
7.10	ANR/Michcon Transportation				-	
7.11	Link Pipeline				-	
7.12	Alliance Pipeline				40,615.4	
7.13	Vector Pipeline - 1st Tranche				8,753.3	
7.14	Vector Pipeline - 2nd Tranche				7,204.2	
7.15	Vector Pipeline - 3rd Tranche				12,947.6	
7.	Total Transportation Costs		11,465.0		229,706.7	
8.	Total Before PGVA Adjustment	0.0	11,465.0	5,473,903.7	1,432,560.3	261.707

MISCELLANEOUS INFORMATION REQUESTS

1) A request was made to have added to the material filed with the application certain information that was reviewed during the settlement and earlier discussions.

2) Parties established that the material could be filed as it was agreed that the information is not confidential, nor would the filing constitute a violation of settlement conference guidelines.

3) The requested information has been filed as attachments 1 through 5 to this exhibit, as follows:

   a. Attachment 1: a series of IR-type responses from EGDI, TransCanada and Union to a questions posed by DR Quinn on behalf of FRPO;

   b. Attachment 2: an expanded response to question 3(b) of Attachment 1;

   c. Attachment 3: email correspondence from Malini Giridhar (Director Energy Supply and Policy, EGDI) to questions posed by Frank Brennan on behalf of Aegent;

   d. Attachment 4: Union Gas has provided us this information on their interruptible volumes as identified in the attached document, in response to an outstanding question asked by DR Quinn on behalf of FRPO.

   In Union South, the Contract Demand for Interruptible Rate Class M5 is 2686.0 10^3m^3 (p. 6 of 10, line 21). Union notes that M5 interruptible volumes are distribution volumes that serve Union's service area towards the Windsor area and are not available for delivery to the Dawn Trafalgar corridor.

In Union North, Union does not identify Contract Demand volumes, as presented in p 4 of 10, line 4 of the attachment.; and

e. Attachment 5: a response from Ian Macpherson (Manager Direct Purchase, EGDI) to a question posed by John Wolnik on behalf of APPrO.

EGD SYSTEM RELIABILITY

Questions of the Federation of Rental-housing Providers of Ontario (FRPO)

1) ECMAP
   a) Will EGD provide recent ECMAP scenarios to provide intervenors with a sense of system planning for emergency situations?

   EGD response:
   The Eastern Canadian Mutual Assistance Plan (ECMAP) is an agreement amongst its members where all or individual members may voluntarily, without any obligation whatsoever, allocate available natural gas and transportation service. ECMAP is intended to assist a member in a situation that results from an unplanned facility outage that causes or will likely cause a supply shortfall to firm customers and cannot be managed through curtailment, maximizing storage and peak shaving facility or facilities or obtaining gas from the marketplace.

   EGD does not incorporate supply from ECMAP in its system planning due to the voluntary nature of the agreement, as described above.

   EGD's mock emergencies are conducted to ensure continuing system preparedness, and are held internally and in conjunction with external parties. In these 'mocks' ECMAP procedures are discussed, however, discussions do not entail any specific voluntary capability that may be available from the signatories to ECMAP.

   In general, EGD notes that a greater proportion of its firm distribution deliveries on peak day are met through discretionary services off TCPL and unplanned facility outages have a greater impact on EGD's customers. On the other hand, mass markets in Union North and GMi are served with firm transportation and unplanned facility outages have a lesser impact as a result of Union North and GMi's contracting practices. Furthermore, Union South has direct access to storage and multiple transportation paths through facilities at Dawn. Also of importance is the fact that Union South, Union North and GMi plans for 44 degree days or higher which provides a greater level of assurance in their ability to meet their system demand.

   TransCanada's Comments Regarding 1a)
   ECMAP (Eastern Canadian Mutual Assistance Plan) is an agreement between; Enbridge Gas Distribution Inc.; Union Gas Limited; Gaz Metro Limited Partnership; Natural Resource Gas Ltd.; The Corporation of the City of Kitchener; and The Corporation of the City of Kingston, Public Utilities Commission. TransCanada is also signatory to the Agreement, however it is merely a facilitating member. While the provisions can be invoked by an LDC under certain emergency conditions, TransCanada would nevertheless be bound by its Tariff and commitments under firm contracts. As such, any restrictions to TransCanada's services must follow its Tariff service priorities whereby non-firm services would be fully curtailed before firm services would be curtailed.

Also, TransCanada suggests that failure to contract appropriately for core market & non-switchable markets (i.e. contract firm transportation to meet peak day requirement) is not normally considered an emergency condition.

b) What is the level of Interruptible Contracting on Union's system? For the purposes of this information, please provide the amount of interruptible contracting on Union's Dawn-Trafalgar corridor.

Union Gas response:
Union Gas has provided information on their in-franchise interruptible rate class customers' annual volumes as follows:

The volumes are made up of system sales and bundled T for M5 in Union South and system sales and T-Service for rate 25 for Union North.

Volumes in 10^3m^3	2008 Actual	2009 Actual
Rate M5	498,466	474,572
Rate 25	306,886	202,146

Union Gas has noted that the Dawn Trafalgar is 100% subscribed for firm transportation. IT volumes can flow on any day that Union South is below a 44 degree day. Union Gas is unable to track what has flowed as IT (from an S&T perspective) because customers can use their basic HUB contract and nominate Dawn to Parkway. There have likely been some one day or short-term IT Dawn to Parkway contracts but Union Gas does not track these volumes.

2) Market Response
a) Can EGD provide the price response (intra-day as available) at Dawn and Niagara throughout the January 15th and 16th period identified as a potential risk due to failure to authorize IT nominations?

EGD response:
Pricing data at Dawn and Niagara for the period January 15th and 16th, 2009 were as follows: (source: Gas Daily)

		Midpoint	Absolute	Common
Flow date(s): 1/15	Dawn, Ontario	6.01	5.93-6.10	5.97-6.05
	Niagara	6.99	6.40-7.70	6.67-7.32
Flow date(s): 1/16	Dawn, Ontario	5.815	5.70-5.87	5.77-5.86
	Niagara	8.13	7.40-9.25	7.67-8.59

b) From TCPL: were there changes in flows (i.e., movement of bottlenecks) between the Timely Window and the subsequent intra-day nomination windows prior to actual flow?

TransCanada's Response to 2b)
Slide 39 of TransCanada's February 25, 2010 presentation to the Working Committee shows the results of capacity allocation process for the Timely nomination cycle on January 15, 2009, which was during a significant cold snap. On this cycle for this day, significant quantities of non-firm transportation services to Enbridge franchise areas were restricted, however firm transportation services were not restricted.

The bottlenecks affecting nominations to the Enbridge franchise areas on January 15, 2009 were the WDA on TransCanada's Northern Ontario Line and TransCanada's M12 capacity on the Union system. At the Evening, Intraday 1 and Intraday 2 cycles on this day, shippers used the opportunity to nominate additional quantities from various sources to the Enbridge franchise areas. Some new nominations to the Enbridge areas on the Evening cycle were impacted by these bottlenecks resulting in some transportation services not being fully authorized. New nominations to the Enbridge franchise areas at the Intraday 1 and Intraday 2 cycles were fully authorized as these transportation paths did not increase flow through any bottlenecks.

TransCanada would also like to highlight a key point of this slide and the supplemental information provided above - there is risk in relying on non-firm transportation services particularly during periods when gas supplies are needed the most.

c) What temporary circumstances lead to the lack of availability of capacity on the TCPL system creating an inability to authorize nominations? What costs could be invested to reduce the risk of future occurrences?

TransCanada's Response to 2c)
In TransCanada's February 25, 2010 presentation to the Working Committee, certain operational information regarding the January 2009 cold snap was provided. Pertaining to question 2c), the impact of the extreme cold weather on TransCanada's Prairie and Northern Ontario Lines included several unplanned outages and several units failed to start. As illustrated on Slide 36, the substantial increase in demand near the middle of this month required starting of several units that were previously not required. Note that there are physical constraints that prevent units from operating outside the flow ranges for which they are designed.

While TransCanada is open to exploring new ideas, such as dollar contributions to increase compressor reliability, TransCanada remains bound by the Tariff and strives to minimize costs. Further, change such as this would require NEB approval of the necessary Tariff changes before it could be implemented. The Tolls Task Force (TTF) is a forum where Mainline stakeholders can discuss such ideas. Detailed analysis for something like this would need to include: impact on fuel, system revenue, and contracting behaviour.

By comparison to today's process, shippers currently have the opportunity to contract for firm services (e.g. FT, STFT) which obligates TransCanada to ensure the necessary compression is available to meet such firm transportation commitments.

d) What percentage of EGD's Peaking Service was not accepted in the timely window?

EGD response:
The following percentages represent the shortfall of peaking service quantities that were called upon and were not confirmed by TCPL at the timely window on January 14th, 2009:

CDA: ~33%
EDA: ~36%

All peaking supplies that EGD had called on were delivered by the end of the January 15th gas day.

What provisions did EGD have in contracts to manage the cost consequences of non-delivery?

EGD response:
In the 2009 peaking contracts the cost consequences for non-delivery were based on the spot price at the closest geographic location relative to the delivery/receipt point for the day or days in question, adjusted for commercially reasonable differences in transportation costs to or from the delivery/receipt point(s).

At the time the spot standard was in place EGD had initiated a process to review and replace contract provisions for failure to deliver.

In the 2010 peaking contracts the cost consequences for non-delivery were based on the cover standard (replacement cost) plus a pro rata share of the demand charge previously paid for by EGD.

Has EGD contracted for service for this winter of similar quality to pre-contracted STFT? If not, what percentage of planned total winter deliveries would meet that criterion?

EGD response:
EGD has not contracted for peaking service for this winter, as of date, either through its RFP for peaking service nor through pre-contracted STFT. Winter STFT as per TCPL's tariff will be available for a five day period during the period July 1-15. EGD's proposal is to replace 200,000 GJ/d of its total winter peaking service requirements with three months of pre-contracted STFT, which is approximately 10% of EGD's planned total winter deliveries.

3) Use of Interruptible Contracts to Meet Winter Peak Demands
   a) From EGD's historical records, what percentage of customers have curtailed inside of the prescribed notification period?

EGD response:
During the most recent period of curtailment which took place in January 2009, 82 incidents of unauthorized supply overrun penalties were reported. EGD had 233 customers contracted under interruptible distribution service rates that were ordered to curtail at that time, resulting in 65% of customers complying with the curtailment order. During instances of ordered curtailment EGD does not measure compliance by counting the number of customers who fail to curtail at the outset of a curtailment period but by the volume of unauthorized supply overrun gas taken by interruptible customers during the curtailment period. This measure is more meaningful as it represents volumes that were expected to be curtailed (or supplied) for which EGD must supply beyond its supply plan. From a historical perspective, EGD experiences varying levels of compliance during each period of ordered curtailment. In recent years EGD has experienced compliance in the range of 65% to 85%.

b) What specifically will EGD be doing to enhance its administrative and auditing process to ensure contractual compliance for the winter of 2010? For the winter of 2011? What is EGD's estimate for the investment it will be making in establishing enhanced protocols and compliance?

EGD response:
EGD has recently completed a number of improvements and has plans to implement other administrative improvements to the curtailment program with the purpose of improving the speed of communicating curtailment notices to customers, reduce administration, better assess expected curtailment impacts and to monitor compliance during periods of curtailment.

EGD proposes to tighten the qualification process for customers applying for service under an interruptible rate by requiring customers to demonstrate their ability to stop using gas or to switch to an alternate fuel source during any period of curtailment. Plans are underway to communicate these changes to customers and to commence the verification process that will include site visits and enhanced record keeping of back up fuel facilities and service interruption plans for individual interruptible rate customers. EGD has recently adopted an IT program called Infoview and has incorporated changes to the software. The purpose of the Infoview application is to facilitate the downloading of current customer consumption during periods of curtailment. Data is initially used to more accurately assess the expected volume of gas that will come off the system during a curtailment. Secondly the program will be used to more rapidly download customer consumption data during a period of curtailment for purposes of identifying and addressing instances of non-compliance.

EGD is not seeking recovery of the costs related to these changes rather these costs will be absorbed by EGD within the current IR framework.

4) Balanced Solution
   a) End use customers are going to be paying the lion share of the costs for increased security of supply and agents will be contributing through a change in their deliveries. What

specific investments, projects and estimated costs, will EGD be making in increasing this security without the need for rate adjustment at this time?

<u>EGD response:</u>
Under EGD's regulatory model, gas supply costs, including gas costs incurred to enhance security of supply are a flow through cost to its customers without mark-up. As stated in response #3, EGD proposes to enhance its administrative processes with respect to firm and interruptible large volume customers. These costs will be absorbed by EGD within the current IR framework.

EGD also participates in ongoing upstream pipeline consultative and industry forums to advocate for lower tolls, short haul capacity and new services that provide competitive alternatives and increase the security of supply for the Ontario natural gas market.

3. Use of Interruptible Contracts to Meet Winter Peak Demands

b) What specifically will EGD be doing to enhance its administrative and auditing process to ensure contractual compliance for the winter of 2010? For the winter of 2011? What is EGD's estimate for the investment it will be making in establishing enhanced protocols and compliance?

Response

b) Enbridge has recently completed a number of improvements and has plans to implement other administrative improvements to the curtailment program with the purpose of improving the speed of communicating curtailment notices to customers, reduce administration, better assess expected curtailment impacts and to monitor compliance during periods of curtailment. EGD estimates that the investment in personnel to address these initiatives is equivalent to 2 full time employees for a period of one year at a total cost of $130,000.

Proposed under the settlement is a tightening of the qualification process for customers applying for service under an interruptible rate by requiring customers to demonstrate their ability to stop using gas or to switch to an alternate fuel source during any period of curtailment. Plans are underway to communicate these changes to customers and to commence the verification process that will include site visits and enhanced record keeping of back up fuel facilities and service interruption plans for individual interruptible rate customers. In the summer of 2009, Enbridge employed a summer student in part to conduct a survey of large volume interruptible customers. The intention of the survey was to gather information regarding customers back up fuel systems and other data regarding customers ability to discontinue service under emergency conditions. The estimated cost of deploying the summer student to this purpose is estimated at $6,000. As well, additional time and effort will be required by Enbridge Account Executives to individually visit each interruptible rate contract site to assess and record curtailment details. This assessment is expected to be conducted as part of the annual contract review process.

Enbridge has recently adopted an IT program called Infoview and has incorporated changes to the software. The purpose of the Infoview application is to facilitate the downloading of current customer consumption during periods of curtailment. Data is initially used to more accurately assess the expected volume of gas that will come off the system during a curtailment. Secondly the program will be used to more rapidly download customer consumption data during a period of curtailment for purposes of identifying and addressing instances of non-compliance. The winter of 2011 will be the first time that the Infoview system will be used to monitor customer compliance for curtailment and additional planning and business processes design is on-going. Enbridge invested $8600 in 2010 to modify the Infoview software to enable Direct Purchase to extract this information. The estimated cost of the Infoview application which serves numerous other business purposes was $300K and was implemented as part of the changes in the scope of EGD's new billing system.

In order to improve the notification of a pending curtailment for customers, Enbridge began automating the customer notification process in 2009 by outfitting all Curtailment Call Representatives with Blackberry's capable of receiving and forwarding curtailment details to customers. This system is substantially faster and more accurate than past phone based communications. This change benefited customers by effectively increasing their curtailment notice period and resulted in reduced administration for Enbridge. Enbridge plans to further leverage Blackberry curtailment functionality by developing a custom Blackberry app intended to further enhance communication and reduce program administration.

Costs related to these and other planned changes have and will be absorbed under Enbridge's Board approved IR costs.

From: Malini Giridhar
Sent: Thursday, April 22, 2010 12:47 PM
To: Frank Brennan; Lorraine Chiasson; Colin.schuch@oeb.gov.on.ca; cripley@uniongas.com; dcnewbury@uniongas.com; Ian.Mondrow@macleoddixon.com; jgirvan@ca.inter.net; lisa_deabreu@transcanada.com; Murray_Ross@transcanada.com; Ken_schubert@transcanada.com; mervin_wallawein@transcanada.com; paul.dumaresq@shell.com; rhiggin@econalysis.ca; Ric.Forster@directenergy.com; VDerose@blgcanada.com; Valerie Young; zafir_samoylove@transcanada.com; steve_emond@transcanada.com; Lawrie.gluck@oeb.gov.on.ca; Rob.rowe@rogers.com; jamie.humble@directenergy.com; brad.janzen@directenergy.com
Cc: Keith Irani; Bob.Betts@sympatico.ca; Bob Betts; Lorraine Chiasson; Norm Ryckman; Robert Bourke
Subject: RE: Working Committee Action Item reminder.

Aegent's comments on the various options identified in the System Reliability Matrix, as indicated in its email below dated April 15th, 2010 will be considered, along with comments from other stakeholders in formulating EGD's proposal.

Further, EGD is compelled to respond to various concerns raised by Aegent in its preamble to its comments on the options currently being discussed.

EGD's comments on Aegent's Preamble

Aegent claims that they "just received today answers to our questions we had posed to Enbridge back in February". This statement is factually incorrect.

Aegent e-mailed written questions to EGD on February 10th . EGD responded to Aegent's questions at the February 25th System Reliability Working Committee meeting. The general discussion of the points raised by Aegent can be found in the Notes from the February 25th Working Committee meeting starting on page 15. The discussion occurred in conjunction with TCPL's presentation of slides 38-40, and responded directly to Aegent's questions on the volumetric shortfall in Jan 2009 and the services associated with the shortfall.

For example, in response to Aegent's assertion below that they still do not know how much of the unauthorized volume was related to direct purchase gas, Paragraph 1 on page 15 of the notes to the February 25th meeting states that of the three suppliers who fell short, two showed the shortfall in peaking service and one in CDS and that all suppliers maintained their direct purchase deliveries.

Subsequent to the February 25th meeting, Aegent requested that EGD provide written responses. Given the substantive discussion on February 25th, and in the absence of further questions from Aegent, EGD presumed that Aegent was seeking a summary of the verbal discussion that had occurred. As Aegent is well aware, EGD and the participants have invested a significant amount of time and resources in the consultative. Indeed, EGD has also been pleased with the level of participation and interest that the various stakeholders have shown in resolving this issue. EGD is disappointed with Aegent's insinuation that not only has EGD been unable to articulate the "problem" and that it has failed in responding to Aegent's questions. EGD wishes to reiterate that it is fully committed to the consultative process in finding a resolution to the system reliability issue.

Secondly, EGD is surprised at Aegent's inability to understand the "problem" in spite of the amount of information and discussions that have taken place on this issue. EGD has consistently stated that the extensive use of discretionary services has the potential to compromise system reliability given the absence of infranchise supply options and the predominantly residential and small commercial nature of EGD's franchise. In fact, TransCanada's presentation, which Aegent admits was 'very helpful', responded directly to the risks associated with the use of discretionary services in the context of capacity shortfalls and system outages that were experienced in 2009. Based on TransCanada's analysis, EGD has come to the conclusion that the use of discretionary services (in particular IT, downstream diversions and STFT contracted on a short term weather forecast) to meet direct purchase deliveries, peaking services and curtailment supplies must be examined. No party in the consultative has demonstrated that direct purchase deliveries for firm customers are met fully or even largely by the use of FT, pre-contracted STFT and upstream diversions – the three services that TransCanada ranks as services with the lowest risk (slide 48 of TransCanada's February 25th presentation).

Below, EGD has further responses to excerpts from Aegent's preamble (in italics).

Our first question to Enbridge asked them to identify the number of pools that didn't nominate their supply (or have their gas scheduled) by the last nomination window, indicating the volume and approximate number of customers in each pool. Enbridge didn't answer the question but instead indicated that on January 15, 37,000 GJ and 34,025 GJ to the CDA and EDA respectively were not authorized by the timely window. According to Enbridge these volumes may have represented some of Enbridge's peaking service gas, some CDS gas or some direct purchase supply. Enbridge hasn't quantified the volume in each category. It would be useful to take a closer look at each of these categories.

EGD's Response:

As noted above, in its February 25th meeting, EGD stated that suppliers reflected the shortfall in peaking supplies and CDS, while maintaining direct purchase deliveries. Also, in its February 25th meeting, EGD observed that suppliers are given the choice to choosing which contracts/services they wish to reflect their shortfall in. If EGD had a policy of not offering suppliers this option, but simply prorated the shortfall across all supply services provided by the supplier (i.e.CDS, peaking and direct purchase) then a shortfall would have occurred in the direct purchase volumes as well.

The table below shows the percentage breakdown of supply services over which suppliers elected to allocate the January 15 shortfall vs. a possible prorata allocation based on a supplier's volumes by type of service.

	CDA GJ	**EDAGJ**
Shortfall	*37,599*	*34,025*
Supplier allocation		
Peaking	75%	100%
MDV		-
CDS	25%	-
EGD allocation		
Peaking	75%	100%
MDV	15%	-
CDS	11%	-

Aegent: During curtailment we purchase CDS gas on behalf of our clients so that they can remain on gas. Sometimes curtailment has been called after the timely window has closed. There have been times when we purchased CDS gas and were told by the supplier that they could only deliver the gas on a "best efforts" basis. In some circumstances, the CDS gas is not scheduled until the first or second intra day window. So it is not surprising to us that some of the CDS was not scheduled in the timely window. However, if the supplier wasn't able to obtain transportation, the customer would need to revert to their backup fuel supply. This does not mean that Enbridge's system would be in jeopardy, it simply means that the customer's gas supply requirement would need to be reduced by the amount of CDS gas that wasn't delivered. This is not new. This has always been the nature of CDS.

EGD's Response:

EGD agrees that customers whose CDS volumes are unsecured are expected to revert to their back up fuel or shut down. However, the fact remains that interruptible customers without backup fuel or the capacity to cease operation are a significant risk to system reliability. As discussed at the last session EGD will be proposing a series of changes to interruptible rate services designed to enhance the effectiveness of interruptible rate services.

<u>EGD's Clarifications on Aegent's comments on the options</u>:

Vertical Slice

STFT is not assignable and therefore cannot be a component of vertical slice. Also EGD is not able to come to the conclusion that large volume non ABC customers are not considered to be a concern because they already rely on firm transportation. EGD proposes that Aegent bring forward information to support this conclusion.

Board's interim solution

In the Decision & Order the Board found that the Interim Board Solution would remain in effect until a permanent solution could be determined and approved by the Board. The Rate Handbook describes the method to be used to calculate the amount to be underpinned by firm transport. Specifically, "each direct shipper will calculate its annual percentage of deliveries for each of the past three winter periods (Jan 1-31) that were underpinned by firm transport, and using the average of these three years' percentages, the direct shipper will add ten percentage points to the average". Nowhere in the Board's Decision or the Rate Handbook is it contemplated that amounts underpinned by firm transportation or the reference years used to derive the base amounts are to be frozen.

Backstopping

EGD proposed short haul FT to provide an indication of costs using this option, since STFT was already being considered for other options. EGD agrees that truly effective backstopping service from Dawn would require short notice services. In its April 8th meeting, EGD indicated that the short notice services are priced at a 30% premium on Union and a 10% premium on TCPL.

In conclusion, EGD has chosen not to respond to some of the more contentious statements made by Aegent in its April 15 email, preferring instead to take them into account, to the best of its ability, in formulating its proposal.

Regards

Malini

Malini Giridhar
Director, Energy Supply and Policy
Enbridge Gas Distribution

Ph: 416 495 5255

From: Frank Brennan [mailto:fbrennan@aegent.ca]
Sent: Thursday, April 15, 2010 4:36 PM
To: Lorraine Chiasson; Colin.schuch@oeb.gov.on.ca; cripley@uniongas.com; dcnewbury@uniongas.com; Ian.Mondrow@macleoddixon.com; jgirvan@ca.inter.net; lisa_deabreu@transcanada.com; Murray_Ross@transcanada.com; Ken_schubert@transcanada.com; mervin_wallawein@transcanada.com; paul.dumaresq@shell.com; rhiggin@econalysis.ca; Ric.Forster@directenergy.com; VDerose@blgcanada.com; Valerie Young; zafir_samoylove@transcanada.com; steve_emond@transcanada.com; Lawrie.gluck@oeb.gov.on.ca; Rob.rowe@rogers.com; jamie.humble@directenergy.com; brad.janzen@directenergy.com
Cc: Malini Giridhar; Keith Irani; Bob.Betts@sympatico.ca; Bob Betts
Subject: RE: Working Committee Action Item reminder.

As a general comment, Aegent decided to participate in the working group because it felt that the system reliability "issue" initially only focused on developing solutions to an ill-defined "problem" and not clearly understanding or defining Enbridge's concern. During the course of the working group meetings, parties requested more information and data in an attempt to better understand the events that unfolded over the January 13-15, 2010 period. We were hopeful that this information would help to clearly define the "problem".The information provided by TransCanada was very helpful in that regard. However, we just received today answers to our questions we had posed to Enbridge back in February.The responses to our questions seem to highlight that Enbridge is not able to better articulate the "problem".

Our first question to Enbridge asked them to identify the number of pools that didn't nominate their supply (or have their gas scheduled) by the last nomination window, indicating the volume and approximate number of customers in each pool. Enbridge didn't answer the question but instead indicated that on January 15, 37,000 GJ and 34,025 GJ to the CDA and EDA, respectively were not authorized by the timely window. According to Enbridge these volumes may have represented some of Enbridge's peaking service gas, some CDS gas or some direct purchase supply. Enbridge hasn't quantified the volume in each category. It would be useful to take a closer look at each of these categories.

During curtailments we purchase CDS gas on behalf of our clients so that they can remain on gas. Sometimes curtailment has been called after the timely window has closed.There have been times when we purchased CDS gas and were told by the supplier that they could only deliver the gas on a "best efforts" basis. In some circumstances, the CDS gas is not scheduled until the first or second intra day window. So it is not surprising to us that some of the CDS was not scheduled in the timely window. However, if the supplier wasn't able to obtain transportation, the customer would need to revert to their backup fuel supply. This does not mean that Enbridge's system would be in jeopardy, it simply means that the customer's gas supply requirement would need to be reduced by the amount of CDS gas that wasn't delivered. This is not new. This has always been the nature of CDS.

If some of Enbridge's peaking service gas was being transported using IT, then this is an issue Enbridge alone needs to address.

What we don't know yet, is how much of the unauthorized volume was related to direct purchase gas. This was the impetus for our question. An answer to this question is, in our view, necessary to get a clearer understanding of whether there is a system reliability "problem" related to Direct Purchase gas supply..

Our third question was: for the pools that didn't nominate (or have their gas scheduled) until the last window, breakout the number of pools that were primarily made up of small volume customers and the number made up of primarily large volume customers. Enbridge's response to this question was "Please see response to question 1". The response to question 1 makes no reference to small volume customers or large volume customers. Does this mean this information is not known?

By the end of the last meeting, we were hoping that the group would have received enough information that would allow the "discovery" phase of the process to conclude. However with Enbridge's responses to our questions, we are not convinced that everyone understands the "problem". To reiterate our initial concern, how can parties provide comments on solutions if we don't know what the problem is?

Notwithstanding our concerns expressed above, we are providing the following comments on the various options identified in the System Reliability Matrix. We feel that this may be our only opportunity to provide comments even though we haven't answered the fundamental question. Many of the comments expressed here would have been made during what we would refer to as a "discussion" phase. We assume that this discussion phase will take place at the next meeting on April 30. It should be noted that we may have additional comments on the "problem " and the options once we go through the discussion phase and we would expect that these additional comments would be captured by Enbridge and included in any filing to the Board.

Comments on Options

1. Vertical Slice

- Enbridge would contract 200,000 GJ/d of long haul FT on TransCanada and then allocate to all Ont ABC customers a slice of each transportation contract (TCPL, Vector, Alliance,etc) held by Enbridge.
- We don't understand why the capacity needs to be long haul and why it needs to be FT and not STFT.
- By contracting for TCPL capacity only, Enbridge will be decreasing diversity of supply compared to what markets and suppliers can offer with delivered supply.
- Based on the information provided to date, large volume non-ABC customers are not considered to be a concern since they already rely of firm transportation.
- There doesn't seem to be any recognition that some DP customers rely on upstream diversions to the CDA from Iroquois, that TCPL indicated are essentially firm. During the Jan 13-15 period all upstream diversions were approved in the first nomination window.

2a Board Interim Solution

- We do not agree with Enbridge's interpretation of the Board's decision that the amount of transportation that needs to be firmed up increases by 10% each year.

2b Enbridge Interim Solution (Modified)

- It appears that this option would require all DP customers (ABC and non-ABC) to hold firm upstream transportation on 90% of their requirements. Seems inconsistent with option 1.
- Greatly reduces diversity of supply if it means having to contract on TCPL.
- There doesn't seem to be any recognition that some DP customers rely on upstream diversions to the CDA from Iroquois, that TCPL indicated are essentially firm. During the Jan 13-15 period all upstream diversions were approved in the first nomination window.

2c Direct Energy

- With the likelihood of additional excess capacity on TCPL, this requirement could be relaxed and reviewed from time to time.

3. Backstopping

- Enbridge would contract for 200,000 GJ/d of shorthaul FT
- We don't understand why Enbridge is proposing FT instead of STFT.
- It appears from the information that TCPL presented that transportation capacity is currently not an issue nor is likely to be going forward. The issue is related more to the contracting of the the excess capacity.
- If Enbridge isn't aware of a supply failure until after the timely nomination has closed, how they propose to use the backstopping capacity?
- Contracting firm transportation for 365 days of the year and only using it one or two days a year seems uneconomic.

4. Curtailment of Firm Customers

- This option would apply to large volume firm customers.
- Most of these large volume customers have contracted for firm transportation capacity because they cannot accommodate an interruption to their gas supply.
- cost of control valves may be prohibitive.
- Enbridge should consider discussing with the large power generators the idea of paying them for the use of their transportation capacity on days when other customers fail to deliver. This would be similar to Enbridge's existing peaking services.

5. Firm Deliveries/ Financial Rating

- Not sure this addresses the consequences of a supplier failing to deliver.

6. EGD Design Day

- Design day would increase from 39.5 degree day to a 43.9 degree day
- This doesn't do anything to address a system reliability concern on peak day
- Enbridge should treat this as a separate issue and take it to the Board if they choose.

7. EGD Peaking Contracts

- This should also be treated as a separate issue. If Enbridge is convinced that the current peaking service arrangements are underpinned by interruptible transportation, then they should address it.
- Maybe contracting for STFT to replace the peaking service arrangements is the action necessary to resolve the system reliability issue.

UNION GAS LIMITED
Northern & Eastern Operations Area
In-franchise Customers
Effective January 1, 2007

Line No.	Particulars	Billing Units	2007 Forecast (1) Usage	Current Approved: Current Approved Revenue ($000's)	Current Approved: Current Approved Rates (2) (cents / m*3)	Revenue (Deficiency) Sufficiency ($000's)	Proposed 2007: Proposed Revenue Requirement (3) ($000's)	Proposed 2007: Revenue Excess/ (Deficiency) ($000's)	Proposed 2007: Proposed Revenue ($000's)	Proposed 2007: Proposed Rates (cents / m*3)	Proposed 2007: Revenue to Cost Ratios	Proposed 2007: Rate Change (%)
			(a)	(b)	(c)	(d) = (b - e)	(e)	(f)	(g)=(e + f)	(h) = (g / a)	(i) = (g / e)	(j) =(h - c) / (c)
	Rate 01 General Service											
1	*Monthly Charge*	bills	3,548,064	49,673	$14.00	(58,113)	107,786	(58,113)	49,673	$14.00	0.461	
	Monthly Delivery Charge - Fort Frances											
2	First 100 m*3	10^3m^3	2,996	290	9.6853	147	143	194	337	11.2523		
3	Next 200 m*3	10^3m^3	4,184	379	9.0482	192	187	253	440	10.5120		
4	Next 200 m*3	10^3m^3	2,022	174	8.6141	88	86	119	205	10.1193		
5	Next 500 m*3	10^3m^3	1,993	164	8.2407	83	81	113	194	9.7280		
6	Over 1000 m*3	10^3m^3	2,170	109	5.0373	55	54	152	206	9.4702		
	Monthly Delivery Charge - Other											
7	First 100 m*3	10^3m^3	203,999	19,758	9.6853	10,013	9,745	13,210	22,954	11.2523		
8	Next 200 m*3	10^3m^3	285,273	25,812	9.0482	13,082	12,730	17,258	29,988	10.5120		
9	Next 200 m*3	10^3m^3	136,595	11,766	8.6141	5,963	5,803	8,019	13,822	10.1193		
10	Next 500 m*3	10^3m^3	130,085	10,720	8.2407	5,433	5,287	7,368	12,655	9.7280		
11	Over 1000 m*3	10^3m^3	135,993	10,870	7.9931	5,509	5,361	7,518	12,879	9.4702		
12	Delivery Commodity charge - 01		905,311	80,043	8.8415	40,566	39,477	54,203	93,679	10.3478		
13	Total Delivery - 01		905,311	129,716	14.3283	(17,547)	147,262	(3,910)	143,352	15.8346	0.973	10.5%
	Gas transportation (4)											
14	Fort Frances	10^3m^3	13,366	405	3.0328	(6)	411	-	415	3.1066		
15	Western	10^3m^3	178,403	5,540	3.1052	(80)	5,620	-	5,669	3.1774		
16	Northern	10^3m^3	397,216	15,101	3.8017	(218)	15,319	-	15,325	3.8581		
17	Eastern	10^3m^3	316,326	13,729	4.3403	(199)	13,928	-	13,870	4.3846		
18	*Transportation - 01*		905,311	34,776	3.8413	(503)	35,279	-	35,279	3.8969	1.000	1.4%
	Storage (4)											
19	Fort Frances	10^3m^3	13,366	258	1.9304	7	251	-	259	1.9351		
20	Western	10^3m^3	178,403	3,578	2.0056	99	3,480	-	3,531	1.9791		
21	Northern	10^3m^3	397,216	9,762	2.4577	269	9,494	-	9,546	2.4031		
22	Eastern	10^3m^3	316,326	8,998	2.8445	248	8,750	-	8,639	2.7311		
23	Storage - 01		905,311	22,596	2.4960	622	21,974	-	21,974	2.4273	1.000	-2.8%
24	*Gas Supply Commodity* (5)	10^3m^3	502,613	156,764	31.1898	(329)	157,093	(329)	156,764	31.1898		
25	Gas Supply Admin	10^3m^3	502,613	1,469	0.2923	(170)	1,640	-	1,640	0.3262		
26	Total Rate 01		905,311	345,321	-	(17,927)	363,248	(4,239)	359,009	-	-	-

Notes:
(1) EB-2005-0520, Exhibit C3, Tab 2, Schedule 1, Column (b)
(2) EB-2005-0290, Appendix A effective July 1, 2005 (Excludes prospective recoveries)
(3) EB-2005-0520, Exhibit G3, Tab 2, Schedules 3-24
(4) *Gas Supply Transportation Rates* will be updated to reflect approved upstream transportation tolls in effect at the time of processing the 2007 rate order.
(5) Gas Supply Commodity and Fuel Rates will be updated as part of the Board approved QRAM process.

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Northern & Eastern Operations Area
In-franchise Customers
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			(a)	(b)	(c)	(d) = (b - e)	(e)	(f)	(g)=(e + f)	(h) = (g / a)	(i) = (g / e)	(j) =(h - c) / (c)
	Rate 10 General Service											
1	Monthly Charge	bills	35,539	2,488	$70.00	(3,240)	5,728	(3,240)	2,488	$70.00		
	Monthly Delivery Charge - All Zones											
2	First 1,000 m*3	10^3m^3	23,408	1,627	6.9493	169	1,458	499	1,957	8.3591		
3	Next 9,000 m*3	10^3m^3	144,913	7,979	5.5060	828	7,151	2,294	9,444	6.5172		
4	Next 20,000 m*3	10^3m^3	102,022	4,780	4.6850	496	4,284	1,376	5,659	5.5472		
5	Next 70,000 m*3	10^3m^3	70,063	2,896	4.1341	301	2,596	845	3,441	4.9114		
6	Over 100,000 m*3	10^3m^3	40,964	871	2.1262	90	781	483	1,264	3.0846		
7	Delivery Commodity charge - 10		381,369	18,153	4.7599	1,884	16,269	5,496	21,765	5.7071		
8	Total Delivery - 10		381,369	20,640	5.4122	(1,356)	21,996	2,257	24,253	6.3594	1.103	17.5%
	Gas transportation (4)											
9	Fort Frances	10^3m^3	2,629	75	2.8422	0	74	-	75	2.8472		
10	Western	10^3m^3	65,506	1,909	2.9146	8	1,902	-	1,911	2.9180		
11	Northern	10^3m^3	146,303	5,283	3.6111	21	5,262	-	5,265	3.5987		
12	Eastern	10^3m^3	164,703	6,835	4.1497	27	6,808	-	6,794	4.1252		
13	Transportation - 10		379,141	14,102	3.7194	56	14,046	-	14,046	3.7046	1.000	-0.4%
	Storage (4)											
14	Fort Frances	10^3m^3	2,629	31	1.1864	1	30	-	32	1.2225		
15	Western	10^3m^3	65,506	826	1.2616	20	807	-	830	1.2666		
16	Northern	10^3m^3	146,303	2,507	1.7137	60	2,447	-	2,473	1.6906		
17	Eastern	10^3m^3	164,703	3,460	2.1005	83	3,376	-	3,325	2.0185		
18	Storage - 10		379,141	6,824	1.8000	165	6,660	-	6,660	1.7566	1.000	-2.4%
19	Gas Supply Commodity (5)	10^3m^3	135,308	42,217	31.2007	(74)	42,291	(74)	42,217	31.2007		
20	Gas Supply Admin	10^3m^3	135,308	395	0.2923	(46)	441	-	441	0.3262		
21	Total Rate 10		381,369	84,179	-	(1,255)	85,434	2,182	87,617	-	-	-

Notes:
(1) EB-2005-0520, Exhibit C3, Tab 2, Schedule 1, Column (b)
(2) EB-2005-0290, Appendix A effective July 1, 2005 (Excludes prospective recoveries)
(3) EB-2005-0520, Exhibit G3, Tab 2, Schedules 3-24
(4) Gas Supply Transportation Rates will be updated to reflect approved upstream transportation tolls in effect at the time of processing the 2007 rate order.
(5) Gas Supply Commodity and Fuel Rates will be updated as part of the Board approved QRAM process.

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			(a)	(b)	(c)	(d) = (b - e)	(e)	(f)	(g)=(e + f)	(h) = (g / a)	(i) = (g / e)	(j) =(h - c) / (c)
	Rate 20 Medium Volume Firm Service											
1	Monthly Charge	bills	768	599	$780.00	(59)	658	(59)	599	$780.00		
	Monthly Demand Charge											
2	First 70,000 m*3	10^3m^3/d	22,606	4,294	18.9962	(6,324)	10,618	(5,623)	4,996	22.0983		
3	All over 70,000 m*3	10^3m^3/d	6,468	739	11.4267	(1,088)	1,827	(980)	847	13.1014		
	Monthly Commodity Charge											
4	First 852,000 m*3	10^3m^3	355,859	942	0.2647	942	-	1,057	1,057	0.2970		
5	All over 852,000 m*3	10^3m^3	169,729	349	0.2057	349	-	367	367	0.2162		
6	Delivery (Commodity/Demand)		525,588	6,325	1.2033	(6,121)	12,446	(5,179)	7,267	1.3826	0.584	14.9%
7	Transportation Account Charge	10^3m^3	408	90	$220.00	-	90	-	90	$220.00		
8	Total Delivery - 20		525,588	7,013	1.3344	(6,180)	13,194	(5,238)	7,956	1.5136	0.603	13.4%
	Gas Supply Demand Charge (4)											
9	Fort Frances		-	-	26.6982	-	-	-	-	24.2297		
10	Western	10^3m^3	2,664	776	29.1152	66	710	-	710	26.6467		
11	Northern	10^3m^3	942	455	48.3112	23	432	-	432	45.8427		
12	Eastern	10^3m^3	4,757	3,004	63.1432	117	2,886	-	2,886	60.6747		
	Commodity transportation 1 (4)											
13	Fort Frances	10^3m^3		-	2.6778	-	-	-	-	2.3560		
14	Western	10^3m^3	25,318	691	2.7278	81	609	-	609	2.4060		
15	Northern	10^3m^3	10,073	319	3.1678	32	287	-	287	2.8460		
16	Eastern	10^3m^3	55,824	1,958	3.5078	180	1,779	-	1,779	3.1860		
	Commodity transportation 2 (4)											
17	Fort Frances			-	0.1113	-	-	-	-	0.1113		
18	Western	10^3m^3	11,140	10	0.0942	-	10	-	10	0.0942		
19	Northern	10^3m^3	10,162	15	0.1469	-	15	-	15	0.1469		
20	Eastern	10^3m^3	59,036	111	0.1883	-	111	-	111	0.1883		
	Storage (GJ's)											
21	Demand	GJ/d	4,632	55	11.820	0	54	-	54	11.738		
22	Commodity	GJ	16,085	4	0.236	(0)	4	-	4	0.241		
23	Gas Supply Transportation - 20		171,554	7,398	4.3121	500	6,897	-	6,897	4.0204	1.000	-6.8%
24	Gas Supply Commodity (5)	10^3m^3	24,982	7,817	31.2916	9	7,808	9	7,817	31.2916		
25	Gas Supply Admin	10^3m^3	24,982	73	0.2923	(8)	81	-	81	0.3262		
26	Total Rate 20		525,588	22,301	-	(5,679)	27,980	(5,229)	22,751	-	-	-

Notes:
(1) EB-2005-0520, Exhibit C3, Tab 2, Schedule 1, Column (b)
(2) EB-2005-0290, Appendix A effective July 1, 2005 (Excludes prospective recoveries)
(3) EB-2005-0520, Exhibit G3, Tab 2, Schedules 3-24
(4) Gas Supply Transportation Rates will be updated to reflect approved upstream transportation tolls in effect at the time of processing the 2007 rate order.
(5) Gas Supply Commodity and Fuel Rates will be updated as part of the Board approved QRAM process.

UNION GAS LIMITED
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Line No.	Particulars	Billing Units	2007 Forecast (1) Usage	Current Approved: Current Approved Revenue ($000's)	Current Approved: Current Approved Rates (2) (cents / m*3)	Revenue (Deficiency) Sufficiency ($000's)	Proposed 2007: Proposed Revenue Requirement (3) ($000's)	Proposed 2007: Revenue Excess/ (Deficiency) ($000's)	Proposed 2007: Proposed Revenue ($000's)	Proposed 2007: Proposed Rates (cents / m*3)	Proposed 2007: Revenue to Cost Ratios	Proposed 2007: Rate Change (%)
			(a)	(b)	(c)	(d) = (b - e)	(e)	(f)	(g)=(e + f)	(h) = (g / a)	(i) = (g / e)	(j) =(h - c) / (c)
	Rate 25 Large Volume Interruptible Service											
1	Monthly Charge	bills	950	181	$190.00	(342)	523	(342)	181	$190.00		
2	Monthly Delivery Charge	10^3m^3	104,645	2,116	2.0224	(2,828)	4,945	(2,579)	2,366	2.2605		
3	Transportation Account Charge	bills	204	45	$220.00	-	45	-	45	$220.00		
4	Total Delivery - 25		104,645	2,342	2.2378	(3,170)	5,512	(2,921)	2,591	2.4759	0.470	10.6%
5	Gas Supply Transport (4)	10^4m^3	41,048	990	2.4120	(87)	1,077	-	1,077	2.6241		
6	Gas Supply Commodity (5)	10^3m^3	41,048	13,396	32.6346	576	12,820	576	13,396	32.6346		
7	Gas Supply Admin	10^3m^3	41,048	120	0.2923	(14)	134	-	134	0.3262		
8	Total Rate 25		104,645	16,848	-	(2,695)	19,542	(2,345)	17,198	-	-	-
	Rate 77 Wholesale Transportation Service											
9	Customer Charge	bills	12	2	$145.00	(2)	3	(2)	2	$145.00		
10	Monthly Delivery Charge	10^3m^3	92	26	28.2609	6	20	6	26	28.4746		
11	Total Rate 77		92	28	30.1440	4	24	4	28	30.3577	1.184	0.7%

Notes:
(1) EB-2005-0520, Exhibit C3, Tab 2, Schedule 1, Column (b)
(2) EB-2005-0290, Appendix A effective July 1, 2005 (Excludes prospective recoveries)
(3) EB-2005-0520, Exhibit G3, Tab 2, Schedules 3-24
(4) Gas Supply Transportation Rates will be updated to reflect approved upstream transportation tolls in effect at the time of processing the 2007 rate order.
(5) Gas Supply Commodity and Fuel Rates will be updated as part of the Board approved QRAM process.

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Northern & Eastern Operations Area
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Line No.	Particulars	Billing Units	2007 Forecast (1) Usage (a)	Current Approved: Current Approved Revenue ($000's) (b)	Current Approved: Current Approved Rates (2) (cents / m*3) (c)	Revenue (Deficiency) Sufficiency ($000's) (d) = (b - e)	Proposed 2007: Proposed Revenue Requirement (3) ($000's) (e)	Proposed 2007: Revenue Excess/ (Deficiency) ($000's) (f)	Proposed 2007: Proposed Revenue ($000's) (g)=(e + f)	Proposed 2007: Proposed Rates (cents / m*3) (h) = (g / a)	Proposed 2007: Revenue to Cost Ratios (i) = (g / e)	Proposed 2007: Rate Change (%) (j) =(h - c) / (c)
	Rate 100 Large Volume Firm Service											
1	Monthly Charge	bills	232	181	$780.00	(29)	210	(29)	181	$780.00		
2	Demand	$10^3m^3/d$	93,386	10,488	11.2304	(8,271)	18,759	(6,648)	12,111	12.9688		
3	Commodity	10^3m^3	2,275,112	4,512	0.1983	4,512	-	4,800	4,800	0.2110		
4	Delivery (Commodity/Demand)		2,275,112	14,999	0.6593	(3,760)	18,759	(1,848)	16,911	0.7433	0.901	12.7%
5	Transportation Account Charge	bills	232	51	$220.00	-	51	-	51	$220.00		
6	Total Delivery - 100		2,275,112	15,231	0.6695	(3,788)	19,020	(1,877)	17,143	0.7535	0.901	12.6%
	Gas Supply Demand Charge (4)											
7	Fort Frances	$10^3m^3/d$	-	-	44.7291	-	-	-	-	42.2176		
8	Western	$10^3m^3/d$	-	-	47.5491	-	-	-	-	45.0376		
9	Northern	$10^3m^3/d$	-	-	69.9441	-	-	-	-	67.4326		
10	Eastern	$10^3m^3/d$	-	-	87.2481	-	-	-	-	84.7366		
	Commodity transportation 1 (4)											
11	Fort Frances	-	-	-	4.9100	-	-		-	4.1215		
12	Western	10^3m^3	-	-	4.9400	-	-	-	-	4.1515		
13	Northern	10^3m^3	-	-	5.2800	-	-	-	-	4.4915		
14	Eastern	10^3m^3	-	-	5.5300	-	-	-	-	4.7415		
	Commodity transportation 2 (4)											
15	Fort Frances	-	-	-	0.1113	-	-	-	-	0.1113		
16	Western	10^3m^3	-	-	0.0942	-	-	-	-	0.0942		
17	Northern	10^3m^3	-	-	0.1469	-	-	-	-	0.1469		
18	Eastern	10^3m^3	-	-	0.1883	-	-	-	-	0.1883		
	Storage (GJ's)											
19	Demand	GJ/d	138,036	1,632	11.820	566	1,066	554	1,620	11.738		
20	Commodity	GJ	871,877	206	0.236	(1,310)	1,516	(1,306)	210	0.241		
21	Gas supply - 100		-	1,837	-	(745)	2,582	(752)	1,830	-	0.709	-
22	Total Rate 100		2,275,112	17,069	-	(4,533)	21,602	(2,628)	18,973	-	-	-

Notes:
(1) EB-2005-0520, Exhibit C3, Tab 2, Schedule 1, Column (b)
(2) EB-2005-0290, Appendix A effective July 1, 2005 (Excludes prospective recoveries)
(3) EB-2005-0520, Exhibit G3, Tab 2, Schedules 3-24
(4) Gas Supply Transportation Rates will be updated to reflect approved upstream transportation tolls in effect at the time of processing the 2007 rate order.

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Line No.	Particulars	Billing Units	2007 Forecast (1) Usage	Current Approved: Current Approved Revenue ($000's)	Current Approved: Current Approved Rates (2) (cents / m*3)	Revenue (Deficiency) Sufficiency ($000's)	Proposed 2007: Proposed Revenue Requirement (3) ($000's)	Revenue Excess/ (Deficiency) ($000's)	Proposed Revenue ($000's)	Proposed Rates (cents / m*3)	Revenue to Cost Ratios	Rate Change (%)
			(a)	(b)	(c)	(d) = (b - e)	(e)	(f)	(g)=(e + f)	(h) = (g / a)	(i) = (g / e)	(j) =(h - c) / (c)
	M2:											
1	Monthly charge	bills	11,844,753	165,827	$14.00	(109,815)	275,641	(109,815)	165,827	$14.00	0.602	
	Monthly delivery comm charge:											
2	First 1 400 m^3	10^3m^3	2,731,111	154,619	5.6614	53,592	101,027	83,443	184,470	6.7544		
3	Next 4 600 m^3	10^3m^3	520,060	21,044	4.0465	1,588	19,456	7,829	27,285	5.2466		
4	Next 124 000 m^3	10^3m^3	663,569	18,941	2.8544	1,429	17,512	8,261	25,773	3.8840		
5	Next 270 000 m^3	10^3m^3	40,749	863	2.1188	65	798	361	1,159	2.8441		
6	All over 400 000 m^3	10^3m^3	7,278	144	1.9749	11	133	62	195	2.6735		
7	Total Delivery - M2		3,962,767	361,438	9.1209	(53,129)	414,568	(9,859)	404,709	10.2128	0.976	12.0%
8	Storage (4)	10^3m^3	3,962,767	37,407	0.9544	(2,896)	40,303	-	40,303	1.0170	1.000	6.6%
9	Gas Supply Commodity (5)	10^3m^3	2,249,002	798,465	35.5031	(181)	798,647	(181)	798,465	35.5031		
10	Gas Supply Admin	10^3m^3	2,249,002	5,580	0.2481	(1,756)	7,336	-	7,336	0.3262		
11	Total Rate M2		3,962,767	1,202,890	-	(57,963)	1,260,853	(10,040)	1,250,812	-	-	-
	M4 Firm comm/ind contract rate											
	Monthly demand charge:											
12	First 8 450 m^3	10^3m^3/d	17,211	8,088	46.9922	(4,582)	12,670	(4,569)	8,101	47.0681		
13	Next 19 700 m^3	10^3m^3/d	7,939	1,396	17.5809	(791)	2,187	(421)	1,765	22.2341		
14	All over 28 150 m^3	10^3m^3/d	860	119	13.8932	(68)	187	(14)	173	20.0900		
	Monthly delivery comm charge:											
15	First Block	10^3m^3	449,247	3,577	0.7963	355	3,223	1,365	4,588	1.0212		
16	All remaining use	10^3m^3	3,779	15	0.3930	1	13	5	18	0.4874		
17	Total Delivery - M4		453,027	13,195	2.9127	(5,085)	18,280	(3,635)	14,645	3.2327	0.801	11.0%
18	Gas Supply Commodity (5)	10^3m^3	23,609	8,382	35.5031	(2)	8,384	(2)	8,382	35.5031		
19	Gas Supply Admin	10^3m^3	23,609	59	0.2481	(18)	77	-	77	0.3262		
20	Total Rate M4		453,027	21,636	-	(5,105)	26,741	(3,637)	23,104	-	-	-
	M5A Interruptible comm/ind contract											
	Firm contracts											
21	Monthly demand charge	10^3m^3/d	2,686	687	25.5770	(214)	901	(103)	797	29.6887		
22	Monthly delivery comm charge	10^3m^3	67,353	1,203	1.7862	731	472	856	1,328	1.9710		
23	Total Delivery - Firm M5		67,353	1,890	2.8061	517	1,373	752	2,125	3.1548	1.548	12.4%
	Interruptible contracts											
24	Monthly Charge	bills	1,632	816	$500	(174)	990	(174)	816	$500		
25	Delivery comm charge(Avg Price)	10^3m^3	337,281	5,145	1.5254	(2,860)	8,005	(1,965)	6,040	1.7908		
	Total Delivery -Interruptible M5		337,281	5,961	1.7673	(3,034)	8,995	(2,139)	6,856	2.0327	0.762	15.0%
26	Gas Supply Commodity (5)	10^3m^3	-	-	35.5031	-	-	-	-	35.5031		
27	Gas Supply Admin	10^3m^3	-	-	0.2481	-	-	-	-	0.3262		
28	Total Rate M5A		404,634	7,851	1.9402	(2,516)	10,367	(1,386)	8,981	2.2195	0.866	14.4%

Notes:
(1) EB-2005-0520, Exhibit C3, Tab 2, Schedule 1, Column (b)
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(3) EB-2005-0520, Exhibit G3, Tab 2, Schedules 3-24
(4) EB-2005-0520, Exhibit H3, Tab 6, Schedule 1, Page 1, Column (g)
(5) Gas Supply Commodity and Fuel Rates will be updated as part of the Board approved QRAM process.
January, 2006

UNION GAS LIMITED
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				Current Approved			Proposed 2007					
Line No.	Particulars	Billing Units	2007 Forecast (1) Usage (a)	Current Approved Revenue ($000's) (b)	Current Approved Rates (2) (cents / m*3) (c)	Revenue (Deficiency) Sufficiency ($000's) (d) = (b - e)	Proposed Revenue Requirement (3) ($000's) (e)	Revenue Excess/ (Deficiency) ($000's) (f)	Proposed Revenue ($000's) (g)=(e + f)	Proposed Rates (cents / m*3) (h) = (g / a)	Revenue to Cost Ratios (i) = (g / e)	Rate Change (%) (j) =(h - c) / (c)
	M7 Special large volume contract											
	Firm contracts											
1	Monthly demand charge	$10^3m^3/d$	22,110	5,498	24.8644	(2,884)	8,381	(2,323)	6,058	27.4000		
2	Monthly delivery comm charge	10^3m^3	266,277	729	0.2739	(552)	1,281	(249)	1,032	0.3875		
3	Total Delivery - Firm M7		266,277	6,227	2.3385	(3,436)	9,663	(2,573)	7,090	2.6626	0.734	13.9%
	Interruptible / Seasonal contracts											
4	Monthly delivery comm charge	10^3m^3	11,269	116	1.0284	(320)	436	(302)	134	1.1905	0.308	15.8%
5	Total Rate M7		277,546	6,343	2.2853	(3,756)	10,098	(2,874)	7,224	2.6029	0.715	13.9%
	M9 Large wholesale service											
6	Monthly demand charge	$10^3m^3/d$	2,694	466	17.2858	(66)	531	(33)	498	18.4938		
7	Monthly delivery comm charge	10^3m^3	24,506	128	0.5233	(5)	134	-	134	0.5450		
8	Total Rate M9		24,506	594	2.4239	(71)	665	(33)	632	2.5784	0.950	6.4%
	M10 Small wholesale service											
9	Monthly delivery comm charge	10^3m^3	202	6	2.7318	(39)	44	(38)	6	3.0783	0.141	12.7%
10	Gas Supply Commodity (4)	10^3m^3	202	72	35.5031	0	72	0	72	35.5031		
11	Gas Supply Admin	10^3m^3	202	1	0.2481	(0)	1	-	1	0.3262		
12	Total Rate M10		202	78	38.4830	(39)	116	(38)	79	38.9076	0.675	1.1%

Notes:
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(3) EB-2005-0520, Exhibit G3, Tab 2, Schedules 3-24
(4) Gas Supply Commodity and Fuel Rates will be updated as part of the Board approved QRAM process.

UNION GAS LIMITED
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Line No.	Particulars	Billing Units	2007 Forecast (1) Usage (a)	Current Approved: Current Approved Revenue ($000's) (b)	Current Approved: Current Approved Rates (2) (cents / m*3) (c)	Revenue (Deficiency) Sufficiency ($000's) (d) = (b - e)	Proposed 2007: Proposed Revenue Requirement (3) ($000's) (e)	Proposed 2007: Revenue Excess/ (Deficiency) ($000's) (f)	Proposed 2007: Proposed Revenue ($000's) (g)=(e + f)	Proposed 2007: Proposed Rates (cents / m*3) (h) = (g / a)	Proposed 2007: Revenue to Cost Ratios (i) = (g / e)	Proposed 2007: Rate Change (%) (j) =(h - c) / (c)
	T1 Storage and Transportation											
	Storage ($/GJ's)											
	Demand:											
	Firm injection / withdrawal											
1	Union provides deliverability inventory	GJ/d/mo.	1,643,806	3,232	1.966	878	2,354	1,240	3,594	2.187		
2	Customer provides deliverability inventory	GJ/d/mo.	1,250,570	1,279	1.023	347	932	484	1,416	1.133		
3	Incremental firm injection right	GJ/d/mo.		-	1.023	-	-	-	-	1.133		
4	Interruptible	GJ/d/mo.	443,760	454	1.023	454	-	503	503	1.133		
5	Space	GJ/d/mo.	155,037,691	1,550	0.010	(124)	1,674	(3)	1,671	0.011		
6	Commodity (Customer Provides)	GJ	25,785,803	103	0.004	(76)	179	15	194	0.008		
7	Commodity (Union Provides)	GJ	-	-	0.056	-	-	-	-	0.064		
8	Customer supplied fuel	GJ	25,785,803	1,536		76	1,460	-	1,460			
	Transportation (cents/ m*3)											
	Demand											
9	First 140 870 m^3	10^3m^3/d/mo.	66,541	11,271	16.9379	(4,655)	15,925	(1,829)	14,096	21.1844		
10	All Over 140 870 m^3	10^4m^3/d/mo.	124,828	15,274	12.2359	(6,308)	21,582	(2,764)	18,818	15.0749		
	Commodity:											
	Firm											
11	First 2 360 653 m3	10^3m^3	1,185,567	1,584	0.1336	241	1,343	301	1,644	0.1387		
12	All Over 2 360 653 m3	10^3m^3	3,444,064	2,698	0.0783	410	2,288	433	2,721	0.0790		
13	Interruptible	10^3m^3	260,358	2,028	0.7788	(1,115)	3,142	(789)	2,353	0.9039		
14	Monthly Charges	Meter/mo.	962	1,732	$1,800	(301)	2,033	(301)	1,732	$1,800		
15	Customer supplied fuel	10^3m^3	4,889,989	10,151	35.5473	577	9,574	-	9,574			
16	Total Rate T1		4,889,989	52,892	1.0816	(9,594)	62,486	(2,710)	59,777	1.2224	0.957	13.0%
	T3											
	Storage ($/GJ's)											
17	Demand:											
18	Firm injection / withdrawal											
19	Union provides deliverability inventory	GJ/d/mo.			1.966					2.187		
20	Customer provides deliverability inventory	GJ/d/mo.	755,172	773	1.023	(76)	849	6	855	1.133		
21	Incremental firm injection right	GJ/d/mo.			1.023					1.133		
22	Interruptible	GJ/d/mo.			1.023					1.133		
23	Space	GJ/d/mo.	38,098,812	381	0.010	(41)	422	(12)	411	0.011		
24	Commodity (Customer Provides)	GJ	6,349,802	25	0.004	(29)	54	(6)	48	0.008		
25	Commodity (Union Provides)	GJ			0.056	-	-	-	-	0.064		
26	Customer supplied fuel	GJ	6,349,802	378		(25)	403	(43)	360			
	Transportation (cents/ m*3)											
27	Demand	10^3m^3/d/mo.	30,696	2,846	9.2725	(300)	3,146	(219)	2,927	9.5355		
28	Commodity	10^3m^3	321,455	236	0.0733	6	229	-	229	0.0714		
29	Monthly Charges	Meter/mo.	12	181	$15,083	(41)	222	-	222	$18,465		
30	Customer supplied fuel	10^3m^3	321,455	667	35.5473	(161)	828	-	828			
31	Total Rate T3		321,455	5,487	1.7070	(666)	6,153	(274)	5,880	1.8291	0.956	7.1%

Notes:
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(3) EB-2005-0520, Exhibit G3, Tab 2, Schedules 3-24

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Line No.	Particulars	Billing Units	2007 Usage (1) (a)	EB-2005-0531: EB-2005-0531 Revenue ($000's) (b)	EB-2005-0531: EB-2005-0531 Rates (2), (4) ($/$10^3m^3$) (c)	Revenue (Deficiency) Sufficiency ($000's) (d) = (b - e)	Proposed 2007: Proposed Revenue Requirement (3) ($000's) (e)	Proposed 2007: Revenue Excess/ (Deficiency) ($000's) (f)	Proposed 2007: Proposed Revenue ($000's) (g) = (e + f)	Proposed 2007: Proposed Rates ($/$10^3m^3$) (h) = (g / a)	Proposed 2007: Revenue to Cost Ratios (i) = (h / e)	Proposed 2007: Rate Change % (j) = (h - c) / (c)
	M12 Storage & Transportation Service											
	Transportation Service:											
	Demand:											
	Dawn to Kirkwall With Dawn Compr.											
1	- 12 months	10^3m^3/d/mo	34,302	30,524	74.131	(4,322)	34,846	(240)	33,998	82.594		
2	- 2 months		3,678	545	74.131	545			608	82.594		
	Dawn to Oakville With Dawn Compr.											
3	- 12 months	10^3m^3/d/mo	79,697	84,252	87.901	(11,015)	95,267	(535)	92,939	97.030		
4	- 2 months	10^3m^3/d/mo	9,237	1,624	87.901	1,624			1,792	97.030		
	Commodity:											
	Easterly With Dawn Compression:											
5	Union Providing Fuel	10^3m^3	4,988	15	3.055	(4)	19	-	19	3.794		
6	Providing Own Fuel	10^3m^3	19,830,801	53,851		(5,587)	59,438	-	59,438			
7	Westerly - Providing Own Fuel	10^3m^3	629,956	864		13	851	-	851			
	Tecumseh Dehydration:											
8	Demand	10^3m^3/d/mo	36,458	738	1.686	100	638	0	638	1.459		
9	Dehydration Commodity	10^3m^3	388,041	18	0.046	(25)	43	-	43	0.111		
10	C1 Margin			(484)		(484)		(2,075)	(2,075)			
11	LBA Margin			(428)		(428)		(75)	(75)			
12	Short Term Deliverability Margin			(19)		(19)		-				
13	M12 Rate Premium							(105)	(105)			
14	Total M12		20,465,745	171,500		(19,602)	191,102	(3,030)	188,072		0.984	9.7%
	M13 Transportation of Locally Produced Gas											
15	Monthly Fixed Charge	monthly	31	129	$ 347	(124)	253	(1)	253	$ 679		
16	Transmission Commodity Charge	10^3m^3	290,605		n/a			298	298	1.024		
17	Commodity	10^3m^3	290,605	746	2.568	406	340	(0)	340	1.169		
18	Total M13		290,605	875		282	, 593	297	890		1.501	1.7%

Notes:
(1) EB-2005-0520, Exhibit C3, Tab 4, Schedule 3.
(2) EB-2005-0531, Appendix A, Pages 17-20.
(3) EB-2005-0520, Exhibit G3, Tabs 2, Schedules 4-21.
(4) The conversion factor used to convert to $/GJ as found in the rate schedules is 37.68 GJ per 10^3m^3.

UNION GAS LIMITED
Southern Operations Area
Exfranchise Customers
Effective January 1, 2007

				EB-2005-0531			Proposed 2007					
Line No.	Particulars	Billing Units	2007 Usage (1)	EB-2005-0531 Revenue ($000's)	EB-2005-0531 Rates (2), (4) ($/$10^3m^3$)	Revenue (Deficiency) Sufficiency ($000's)	Proposed Revenue Requirement (3) ($000's)	Revenue Excess/ (Deficiency) ($000's)	Proposed Revenue ($000's)	Proposed Rates ($/$10^3m^3$)	Revenue to Cost Ratios	Rate Change %
			(a)	(b)	(c)	(d) = (b - e)	(e)	(f)	(g) = (e + f)	(h) = (g / a)	(i) = (h / e)	(j) = (h - c) / (c)
	M16 Storage Transportation Services											
1	Monthly Fixed Charge	monthly	2	13	$ 525	(7)	20	(0)	20	$ 817		
2	Transmission Commodity Charge	10^3m^3	86,351	83	0.958	83		88	88	1.024		
	Charges West of Dawn:											
3	Firm Demand Charge	10^3m^3/d	279	132	39.523	(22)	154	1	155	46.375		
4	Fuel & UFG to Dawn	10^3m^3	46,503	51	1.090	(4)	54	(0)	54	1.169		
5	Fuel & UFG to Pool	10^3m^3	46,731	78	1.661	(5)	83	(0)	83	1.768		
	Charges East of Dawn:											
6	Firm Demand Charge	10^3m^3/d	240	79	27.339	79		87	87	30.179		
7	Fuel & UFG to Dawn	10^3m^3	39,848	43	1.090	(3)	47	(0)	47	1.169		
8	Fuel & UFG to Pool	10^3m^3	40,325	56	1.391	(4)	60	1	61	1.509		
9	Total M16		173,407	534		116	418	177	595		1.423	11.3%
	C1 Storage & Cross Franchise Transportation Service											
	Storage Service:											
10	Peak Storage(Short Term)	10^3m^3	112,002	1,794		902	891	902	1,794			
11	Peak Storage(Long Term)	10^3m^3	3,572,650	50,028		27,658	22,370	27,658	50,028			
12	Off Peak Storage, Balancing & Loans	10^3m^3	1,273,885	4,092		2,798	1,294	2,798	4,092			
13	Commodity - providing own fuel	10^3m^3	3,572,650	8,005		391	7,614	-	7,614			
	Transportation Service:											
	Demand:											
	St.Clair & Dawn, Ojibway & Dawn											
14	- 12 months	10^3m^3/mo	1,023	485	39.523	(84)	569	0	569	46.375		
15	Parkway to Dawn/Kirkwall	10^3m^3/mo	3,405	876	21.447	876		919	919	22.485		
	Dawn to Parkway											
16	- 12 months		396	924	87.901	275	649	299	925	97.030		
17	- 2 months	10^3m^3/mo	92	23	87.901	23			23	97.030		
	Firm Commodity											
18	Parkway to Kirkwall	10^3m^3	515,750	641	1.229	(20)	661	(31)	630	1.222		
19	Dawn to Parkway - customer supplied fuel	10^3m^3	149,800	603		186	417	(3)	414			
20	Capacity Rebate			(6)		(6)		(23)	(23)			
21	Interruptible Transportation & Exchanges	10^3m^3	983,597	4,000	4.067	2,107	1,893	2,107	4,000	4.067		
22	Commodity - providing own fuel	10^3m^3		668		135	533	(5)	528			
23	L.B.A.			75		75		75	75			
24	Other Transactional	10^3m^3		895		853	42	853	895			
25	Total C1		1,649,147	73,103		36,170	36,934	35,549	72,483		1.963	-0.8%

Notes:
(1) EB-2005-0520, Exhibit C3, Tab 4, Schedule 3.
(2) EB-2005-0531, Appendix A, Pages 17-20.
(3) EB-2005-0520, Exhibit G3, Tabs 2, Schedules 4-21.
(4) The conversion factor used to convert to $/GJ as found in the rate schedules is 37.68 GJ per 10^3m^3.

APPrO has a question regarding the draft Rate Handbook changes proposed by Enbridge in its System Reliability Proposal.

Background

Enbridge proposes to introduce a new provision regarding customers providing 2 business days notice if it wishes to suspend deliveries. Further Enbridge notes that any shortfall in delivered volume without notice will be treated as Unauthorized Supply Overrun and also consumption of Unauthorized Supply Overrun Volume could result in a cessation of service.

Large volume customers like generators, may not from time to time have full control of their production profile. The BGA is a helpful tool to manage the variances between the supply and consumption. Requiring 2 business days notice (up to 5 actual days if a long weekend is involved) could now result in higher BGA balances than would otherwise be the case.

Enbridge also notes at the bottom of page 10 of the draft Settlement Agreement, that notices for balancing suspensions are pre-authorized by Enbridge through EnTrac. APPrO understands that there are certain times during the month that EnTrac is not available to make such notices.

Question

In light of this new 2 business day notice provision for suspensions, will Enbridge increase the flexibility for customers to reduce their BGA balance provided that such request does not occur during peak days or OFO days?

<u>EGD Response</u>

The EnTRAC system is taken off line monthly, for a two hour period, to perform routine maintenance and testing. Maintenance periods occur after hours and the schedule for such periods is published on Enbridge's customer portal one year in advance. Including these planned outages, EnTRAC averages availability greater than 99.9%, so we do not expect system availability to impact customer requests for self-suspension. However, in extreme circumstances, Enbridge would accommodate manually written requests for self-suspension.

Enbridge's ability to offer some load balancing services is subject solely to operational limitations and is not impacted by EnTRAC availability.

Availability of some load balancing options (including suspensions, make-up) are determined by an Enbridge cross functional team that meets on a regular basis to review near term projections of supply and demand, and make decisions to adjust the levels of seasonal supply if necessary. Based on these factors the team determines whether EGD can offer suspensions and/ or makeup without affecting storage targets while continuing to meet customers' demands. Once a level of these services is determined, they are offered on a go forward first come first serve basis. As Enbridge already allows the maximum amount of load balancing services based on the operational considerations present at that time, therefore, Enbridge cannot increase the flexibility of these services. Customers also have access to a number of other load balancing tools (in-franchise title transfers, enhanced title transfers, BGA rollovers, general service account adjustments, and mid-term enrollment of accounts) which are not subject to the types of operational restrictions experienced for suspensions and make-up.

Please note that Enbridge expects to implement MDV re-establishment and General Service Account weather normalization functionality in the first quarter of 2011. Among other benefits this change is expected to reduce the reliance of the Direct Purchase market on load balancing. The EnTRAC system will be changed to automatically amend MDV on a monthly basis to reflect account migration, and the normalization adjustment is expected to have a smoothing effect on BGA balances.