EB-2009-0139

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Toronto Hydro-Electric System Limited for an Order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2010 (the "Toronto Hydro 2010 Rates Application").

POLLUTION PROBE

CROSS-EXAMINATION REFERENCE BOOK

February 5, 2010

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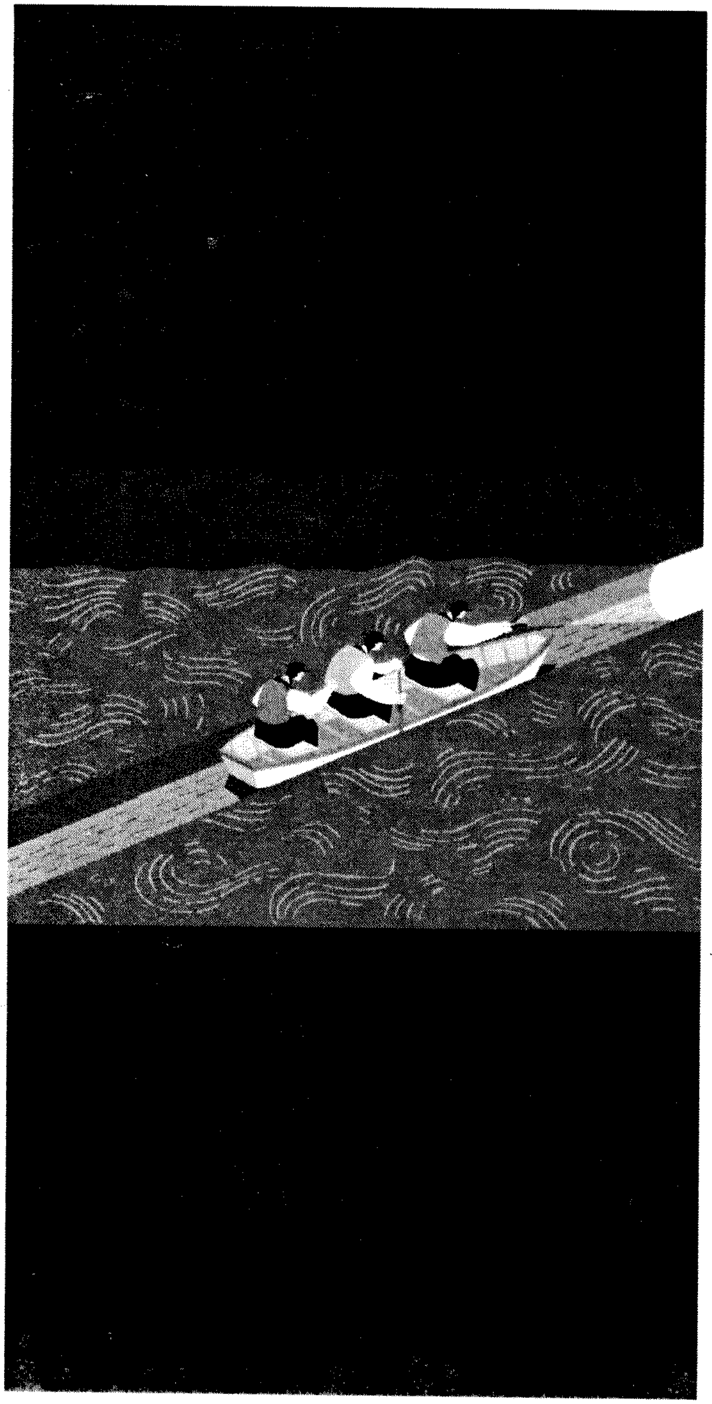

Central and Downtown Toronto Distributed Generation

Final Report

Prepared for:

toronto hydro electric system

Ontario Power Authority

July 28, 2009

Navigant Consulting, Inc.
1 Adelaide Street East, Suite 2601
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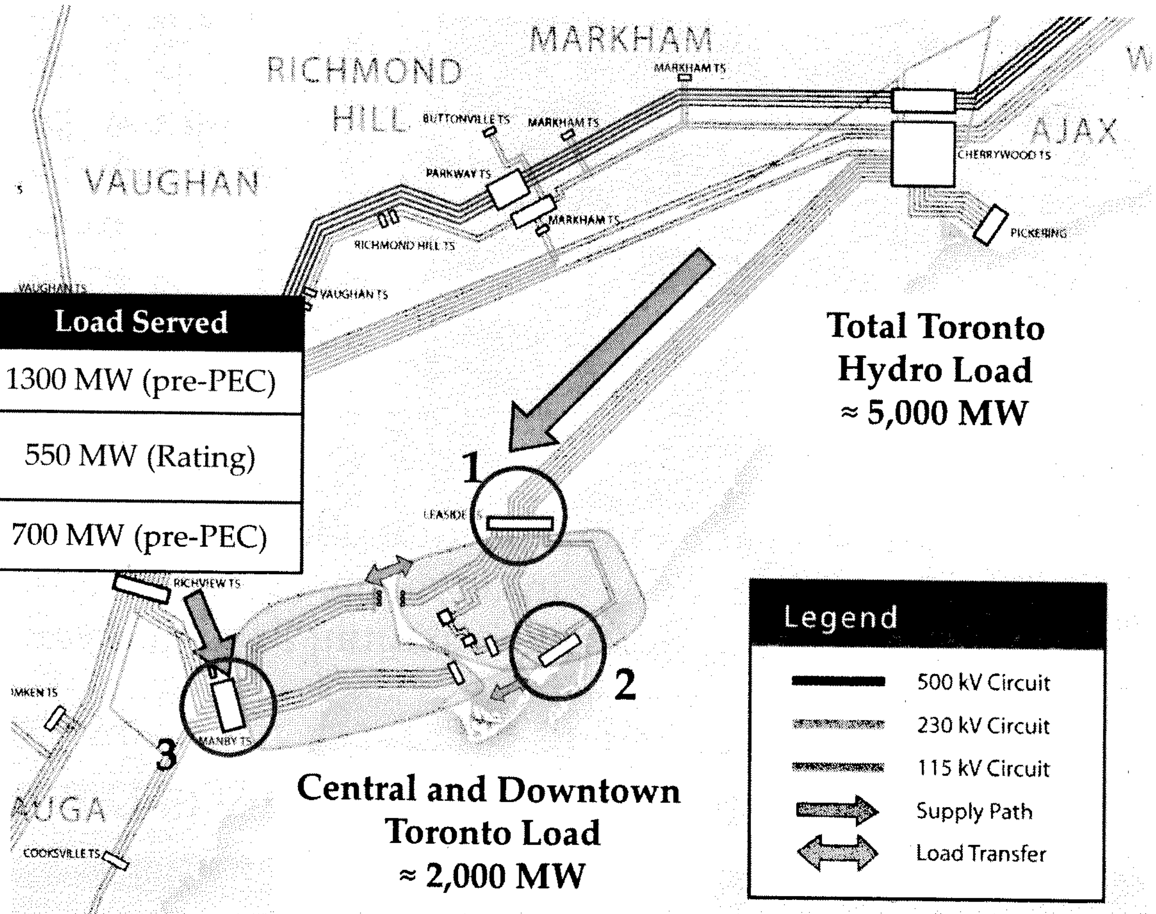
NAVIGANT CONSULTING

Two key transmission and supply sources serve Central and Downtown Toronto, an area with a peak demand of ~ 2,000 MW.

- Two supply systems, Leaside and Manby, serve the Central and Downtown Toronto area, with the Portland Energy Center connected at Hearn to support the Leaside system.

Source	Load Served
1) Leaside	1300 MW (pre-PEC)
2) Portland Energy Center (PEC) at Hearn	550 MW (Rating)
2) Manby	700 MW (pre-PEC)



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Toronto Hydro-Electric System Limited
EB-2009-0139
Exhibit Q1
Tab 4
Schedule 1-1
ORIGINAL
(9 pages)

EXECUTIVE SUMMARY: DISTRIBUTED GENERATION IN CENTRAL AND DOWNTOWN TORONTO

Presented to

toronto hydro electric system

Ontario Power Authority™

JULY 28, 2009

Navigant Consulting Inc.
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Background

With a peak demand of some 2,000 MW (representing about 40% of the roughly 5,000 MW peak demand for Toronto Hydro's entire service territory), Central and Downtown Toronto faces a number of potential electricity system reliability challenges in the 2015 – 2017 timeframe including the need for additional area supply capacity, infrastructure renewal, and supply diversity to mitigate against low probability but high impact events.

Toronto Hydro and the Ontario Power Authority (OPA) retained Navigant Consulting to evaluate the potential for distributed generation (DG) to address some or all of these needs. This study responds directly to a request to Toronto Hydro by the Ontario Energy Board to investigate the potential for DG in its service territory and to a directive from the Minister of Energy and Infrastructure to the OPA to revisit the renewable generation, DG and conservation and demand management (CDM) targets in its Integrated Power System Plan (IPSP). During the course of the study, the Ontario government passed the Green Energy Act, which further enhances Ontario's focus on renewable generation, DG, and CDM.

Local Electrical System Characteristics

Three key transmission and supply sources serve Central and Downtown Toronto:

- Leaside Transformer Station (TS), serving approximately 1300 MW (pre-PEC operation)
- Portlands Energy Centre (PEC) at Hearn TS, with a rated capacity of 550 MW
- Manby (East and West) TS, serving approximately 700 MW

Leaside TS requires a major refurbishment sometime in the next three to five years for asset end-of-life replacement. Limited short circuit or fault current capacity at Leaside TS (and Manby TS) is currently a constraint on certain types of DG in Central and Downtown Toronto. The planned refurbishment provides an opportunity to upgrade the short circuit capacity at Leaside TS, which would enable higher levels of DG.

However, the transmission and supply sources will have limited capacity to serve load if a loss of a significant portion of Leaside TS capability were to occur. The IPSP indicates that a deficit of approximately 300 MW would occur if such a low probability, high impact event were to occur.

In addition to the Leaside TS refurbishment, the IPSP indicates that a major transmission upgrade is being assessed as one of the options to serve the Central and Downtown Toronto area (DG is another option being assessed). The upgrade would increase transmission capacity into Central and Downtown Toronto by up to 700 MW and is expected to cost more than $500 million. The most likely timing for any such upgrade would be in the 2016 – 2018 timeframe.

Estimating value of deferring the major transmission upgrade to Central and Downtown Toronto

- Using a similar methodology as for the example given, Navigant Consulting estimated the potential value associated with deferral of the major transmission upgrade through distributed generation
- Key assumptions in the analysis are as follows
  - For the purpose of meeting system capacity, the upgrade would be required in the 2020 – 2025 period (Navigant Consulting used 2022 in our analysis). The earlier need date in the 2017-2018 time period is driven by infrastructure renewal needs and to mitigate vulnerability to high impact events (not peak demand capacity needs)
  - Peak demand growth in Central and Downtown Toronto during the period from 2017 to 2027 is forecast to be approximately 30 MW annually
  - 120 MW of distributed generation capacity is assumed, resulting in a 4 year deferral (eg, 120 MW / 30 MW demand growth per year)
- Deferral value is expressed in 2011$ to reflect likely basis for the evaluated costs associated with the peaking gas plant used for cost comparison (allows "apples-to-apples" comparison of these costs)

Widespread DG development could potentially defer a major transmission system upgrade.

- Widespread installation of distributed generation in Central and Downtown Toronto could potentially defer the need for any major transmission system upgrade(s).
- The OPA's 2007 IPSP submission (Exhibit E, Tab 5, Schedule 5) discusses three transmission upgrade options
  - All three options would address local system capacity growth, infrastructure renewal needs and mitigate vulnerability to high impact events
  - Costs for the options range from $510 million to $640 million (2007$) and would increase transmission capacity into Central and Downtown Toronto by up to 700 MW
- For the purposes of estimating the potential deferral value through distribution generation, Navigant Consulting has approximated the cost of the major transmission upgrade as $1 million / MW (eg, $600 million for 600 MW capacity upgrade)

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Ontario Energy Board

Commission de l'Énergie de l'Ontario

VT INCEPIT FIDELIS SIC PERMANET

Ontario

ONTARIO ENERGY BOARD

Transmission System Code

October 20, 2009

any customer. Subject to section 6.2.16, before disclosing the available capacity on a connection facility that serves only one customer, the transmitter shall obtain the consent of that customer. Where such consent cannot be obtained, the transmitter may request guidance from the Board.

6.3 COST RESPONSIBILITY FOR NEW AND MODIFIED CONNECTIONS

6.3.1 Where a load customer elects to be served by transmitter-owned connection facilities, a transmitter shall require a capital contribution from the load customer to cover the cost of a connection facility required to meet the load customer's needs. A capital contribution may only be required to the extent that the cost of the connection facility is not recoverable in connection rate revenues. To that end, the transmitter shall include in the economic evaluation the relevant annual connection rate revenues over the applicable economic evaluation period that are derived from that part of the customer's new load that exceeds the total normal supply capacity of any connection facility already serving the customer and that will be served by the new connection facility. The transmitter shall calculate any capital contribution to be made by the load customer using the economic evaluation methodology set out in section 6.5.

6.3.2 Where a transmitter has to modify a transmitter-owned connection facility to meet a load customer's needs, the transmitter shall require the load customer to make a capital contribution to cover the cost of the modification. A capital contribution may only be required to the extent that the cost of the modification to the connection facility is not recoverable in connection rate revenues. To that end, the transmitter shall include in the economic evaluation the relevant annual connection rate revenues over the applicable economic evaluation period that are derived from that part of the customer's new load that exceeds the total normal supply capacity of any connection facility already serving the customer and that will be served by the modified connection facility. The transmitter shall calculate any capital contribution to be made by the load customer using the economic evaluation methodology set out in section 6.5.

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toronto hydro
corporation

July 13, 2007

Councillor Paula Fletcher
City Hall
100 Queen Street West, Suite C44
Toronto, ON M5H 2N2

Dear Councillor Fletcher,

Further to our conversation yesterday regarding the information released by Toronto Hydro at a meeting on July 10th, I want to state emphatically that neither Toronto Hydro nor Hydro One is pursuing any option such as the so called "Third Line" as the preferred solution to the security of supply issues facing the city. Minister Duncan has made it very clear that the government does not support the Third Line as an option and we support that opinion. The meeting in question was part of our outreach to our stakeholders as we prepare for our 2008 rate application to the Ontario Energy Board. Unfortunately a piece of outdated information was included in the presentation, which gave the impression that Toronto Hydro and Hydro One were pursuing the "Third Line" option. Nothing could be further from the truth. I would like to apologize for this misinformation and as the head of Toronto Hydro Corporation, I take full responsibility for this unfortunate incident.

The material that has been provided to you by Mr. Gibbons has been taken out of context, and it was made very clear by my staff to all in attendance that Toronto Hydro is, first and foremost, committed to seeking demand side management and distributed generation solutions to the supply concerns that all parties recognize must be addressed. This is consistent with public statements from the Minister and Ontario Power Authority. Toronto Hydro will continue to seek solutions to this issue through prudent conservation measures, using the tools that have been made available to us by the provincial government.

I know that you understand that we must find a solution to the supply constraints to Toronto as soon as possible. We will ensure that the process that is put in place to find the answers is open, transparent, includes a significant focus on DSM, and will meet the needs of Toronto. We have serious concerns about the security of our supply in that we do not have enough capacity in the transmission lines feeding Toronto to switch between these lines, should there be a failure of one or both of the lines. Our objective is to finally begin to address the issue and no longer ignore a problem that has been building for the last 20 years. Our intention is to explore all options to find an acceptable solution that provides adequate security for Toronto's electricity supply.

The preferred solution is DSM and other conservation options and we are committed to full public discussion about this. I want to reiterate that we are not pursuing any options other than DSM and other conservation measures. You have my personal commitment that conservation will always be our priority as a first line of defence against the infrastructure issues that we face. We have committed hundreds of millions of dollars to maintain and rebuild our distribution system in Toronto, and we will continue to supplement our capital expenditures by using all options available to us to meet demand growth through conservation.

Toronto Hydro Corporation has taken the lead on so many DSM initiatives. We have much more to do, and we are pushing forward aggressively. Please be assured that we will be looking to fully exploit DSM opportunities in the context of resolving the security of supply issue, and that we will be seeking your assistance in this regard.

Sincerely,

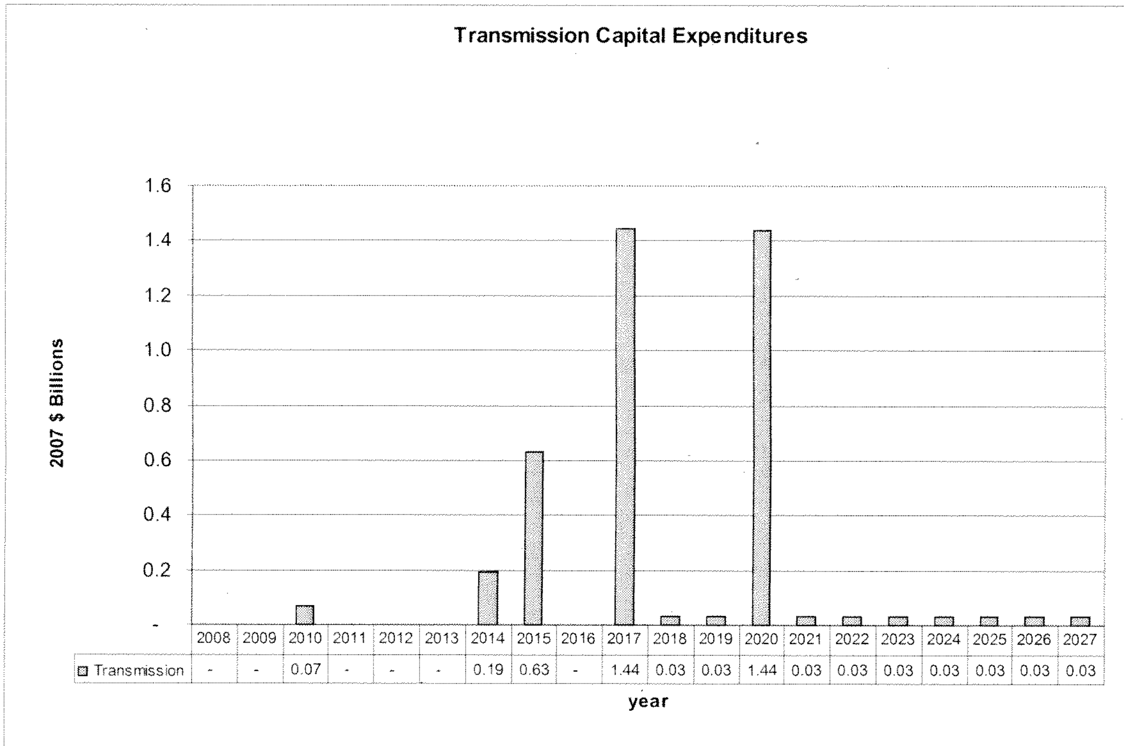
David S. O'Brien

David S. O'Brien
President and Chief Executive Officer

\cb

Cc: The Honourable Dwight Duncan, Minister of Energy
Mayor David Miller
Peter Tabuns, MPP (Toronto-Danforth)
Dr. Jan Carr, Chief Executive Officer, Ontario Power Authority
Jack Gibbons, Chair, Ontario Clean Air Alliance
Laura Formusa, Acting President and CEO, Hydro One Inc.

Figure 6: Forecast Expenditures on New Transmission Investments (2007 $Billions)



Source: OPA

Q. What assumptions were used to develop the Plan cost?

A. The assumptions used to derive these costs are set out in Table 1 which shows the capital and operating cost assumptions of planned generation.

Table 1: Cost Assumptions for Planned Generation

GENERATION TYPE	Capital Cost $/kw	Construction Period (years)	Fixed O&M $/kw	Variable O&M $/MWh	Heat Rate	Operating Life
CCGT	924	3	17.0	2.7	7,150	20
SCGT	665	2	16.0	3.5	9,141	20
Biogas	2,096	2	231.0	27.0	14,800	20
Cogen	1,413	3	22.0	2.7	7000	20
Hydro RR	3,570	4	41.8	0.0		50
Hydro DIS	2,550	4	41.8	0.0		50
Nuclear	2,907	6	108.1	3.1	10,500	40
Wind	1,938	1	47.9	0.0		20
NUG replacing CCGT	924	3	17.0	2.7	8011	20
Fuel Cell	5,447	3	8.3	54.1	7,930	20
Solar	5,712	2	13.3	0.0	10,280	20
Nuclear Refurbishment Cost $M per unit	1,514					

Source: OPA

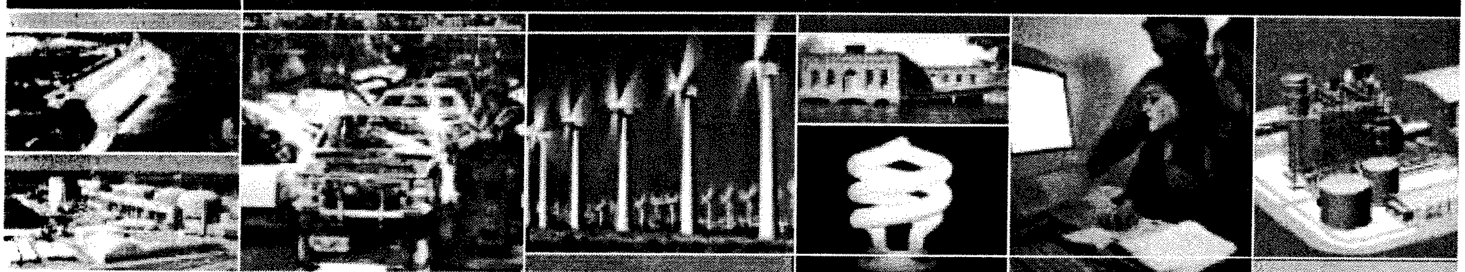
$\frac{3413}{9141} = 0.37$

2

ONTARIO POWER AUTHORITY

Supply Mix Analysis Report

Volume 2 – December 2005



Ontario Power Authority

Combined Cycle: Combined cycle generators can start and ramp up to full power within a couple of hours, and can run at a variety of output levels. CC generators can provide both peaking and base load service, but are most useful as intermediate generation. CC generation has a higher capital cost but a lower operating cost than simple cycle generation. As a result, it tends to run more often than simple cycle, but is more efficient when running.

CHP or Cogeneration: Combined heat and power generation is useful as base-load generation. CHP has higher capital costs than SC and CC, but has higher efficiency. The total fuel consumed by a CHP system is less than the total fuel consumed by two separate systems, one producing electricity, and another producing thermal energy. Efficiencies before heat recovery range from 25 per cent to 40 per cent, while overall efficiency after heat recovery could reach 80 to 90 per cent.
One factor that affects cogeneration system economics is system availability and reliability. Electricity is not produced during hours when the cogeneration system is down. Not only must electricity be purchased, but outages can also affect costs of standby service.

Fuel Cells: Large fuel cells are able to generate electricity more efficiently than combustion power plants. The fuel-cell technologies being developed for these power plants generate electricity directly from hydrogen in the fuel cell, but will also use the heat and water produced in the cell to power steam turbines and generate even more electricity.

Fuel cells are ideal for power generation, either connected to the electric grid to provide supplemental power and backup assurance for critical areas, or installed as a grid-independent generator for on-site service in areas that are inaccessible by power lines. Since fuel cells operate silently, they reduce noise pollution as well as air pollution and the waste heat from a fuel cell can be used to provide hot water or space heating for a home.

Modular installation (the installation of several identical units to provide a desired quantity of electricity) provides extremely high reliability of up to 99 percent.

If the fuel cell is powered with pure hydrogen, it has the potential to be up to 80-percent efficient. That is, it converts 80 percent of the energy content of the hydrogen into electrical energy. If another fuel such as methane is used, in which case a reformer is required to convert the methanol to hydrogen, the overall efficiency drops to about 30 to 40 percent.

2.7.8.3 Costs

The capital cost of the gas turbine power plants depends on the size of the plant and the selected technology of turbine systems. The main components of generation costs are the installed cost of the equipment, fuel costs, and non-fuel operation and maintenance (O&M) costs. Fuel cell costs per installed kilowatt are still high relative to those of conventional technology.

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ONTARIO
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Combined Heat and Power Survey for Health Care Facilities

Overview

1. How many beds does your facility have? ~700

2. What energy efficiency initiatives has your facility employed within the past 5 years? What plans do you have going forward?

Many retro-commision, retrofit and behaviour projects completed, underway and planned

What is the age of your facility's boiler plant? <10 years (TWH)

Electricity Consumption

1. What is your winter peak demand (MW)? 15 MW

2. What is your average demand (MW) during the months of December to March (inclusive)? 14 MW

3. What is your summer peak demand (MW)? 22 MW

4. What is your average daily demand (MW) during the months of June to August (inclusive)? 21 MW

5. What is your annual electricity consumption (MWh)? ~120 million kW

6. Please provide a percentage break-out of your annual electricity consumption by end-use (e.g., lighting, plug loads, space heating (if applicable), water heating (if applicable), ventilation, cooling, cooking, drying, sterilization). If you do not have end-use metering, please provide your best estimates.

N/A

7. How many hours a year do your electric chillers operate? N/A - 24/7?

Emergency Generators

1. What is the total capacity (MW) of your emergency generators? Please break-out your response by fuel type (e.g., diesel, natural gas).

diesel - 14 MW

continued on next page

2. How many days of diesel fuel supply do you have on site assuming that the diesel generators are operating at full capacity? N/A

3. Does your diesel fuel supplier have a legal obligation to provide you with sufficient fuel to operate your diesel generators at full capacity during a blackout? If "yes" for how many days? If your supplier fails to fulfill this obligation what financial penalties is it subject to? Who is your diesel fuel supplier?

~~N/A~~

Natural Gas Consumption

1. What is your average daily demand for natural gas during the months December to March (inclusive)?
16,000 m3

2. What is your average daily demand for natural gas during the months June to August (inclusive)?
7200

3. What is your annual minimum daily demand for natural gas? N/A

4. Please provide a percentage break-out of your annual natural gas consumption by end-use (e.g., space heating, water heating, cooking, drying, absorption cooling (if applicable), electricity generation, sterilization). If you do not have end-use metering, please provide your best estimates.
N/A

5. Do you obtain thermal energy from a third party via a district energy system? yes - steam for TC

Combined Heat and Power

1. Has your facility ever looked at installing a CHP plant? If so, how long ago?
yes - 2002

Please indicate what the barriers are to installing a CHP unit.
capital costs, no "rules" for CHP to help build business case

2. What do you consider would be the most significant benefits to your facility from a CHP unit?
potential cost savings

Name Ed Rubinstein **Date** Oct. 29, 2009

Title Manager, Energy & Environment **Institution** University Health Network

Please return to:
Jack Gibbons, Ontario Clean Air Alliance, Suite 402, 625 Church St., M4Y 2G1
Fax 416-926-1601, email jack@cleanairalliance.org, Phone 416-926-1907 x240

Electricity from distributed generation is not subject to losses, whereas electricity from a central plant would be

- Another potential benefit of distributed generation is that the electricity is produced and consumed locally. As a result, there are negligible, if any, losses associated with this electricity. One the other hand, electricity produced at a central generating station is subject to losses in the transmission and distribution system.
- A 2005 Navigant Consulting study for Hydro One entitled *"Avoided Cost Analysis for the Evaluation of CDM Measures"* explored transmission system losses across the entire Ontario transmission grid and found that average losses were approximately 2.5% across Ontario and average marginal losses were approximately 6%. An 2007 IESO study for the OPA estimated that marginal losses during the top 100 hours of the year were over 10%
  - Losses vary by time of day and season, but also vary by location. Different types of distributed generation have different operating profiles, hence the energy they produce would otherwise be subject to different loss factors.
  - Further, given the recent commissioning of the Portlands Energy Centre, a significant portion of Central and Downtown Toronto load will be served locally, with another large source of supply being Pickering Nuclear Generation Station just east of Toronto. Given this, Central and Downtown Toronto may be subject to lower losses than other locations more remote from large, central plants.
  - Based on these considerations, Navigant Consulting expects that the avoided marginal transmission losses during peak demand periods for energy produced by distributed generation could fall in the range of 3% - 6%

The report is available from the Ontario Energy Board website at: http://www.oeb.gov.on.ca/documents/cases/RP-2004-0203/dcdm_hydro_acar_170605.pdf

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Navigant Consulting estimates avoided marginal losses from 4% - 8% during peak demand periods for energy from distributed generation

*

- Toronto Hydro's Total Loss Factors range from 0.85% for primary metered customers with demand greater than 5,000 kW to 3.8% for secondary metered customers with demand less than 5000 kW. A significant amount of the distributed generation capacity will be connected at large customer facilities (that would otherwise be subject to lower losses) and the mesh network serving Toronto Hydro's high density Central and Downtown Toronto core is expected to have lower losses than other areas of Toronto served by Toronto Hydro
  - Based on these considerations, Navigant Consulting expects that the avoided marginal distribution losses on the Toronto Hydro system during peak demand periods for energy produced by distributed generation could fall in the range of 1% - 2%
- Combining these two estimates – for transmission and distribution losses – yields an expected avoided marginal losses in the range of 4% - 8% losses during peak demand periods.
  - In simple terms, and assuming 5% losses, 1 MW of distribution generation would be equivalent to 1/(1-5%) = 1.052 MW of "central" plant capacity. If the distributed generation facility had a capacity of 2 MW, this would be equivalent to 2.1 MW of central plant capacity.
  - Because the evaluated costs presented earlier in this report did not account for this "scaling up" of distributed generation capacity to account for such losses, the evaluated costs ($/MW) for distributed generation technologies should be adjusted to account for the fact that 1 MW of distributed generation is equivalent to more than 1 MW of central plant. The specific adjustments for the two loss factors in the range above would be 4% and 8% reduction in the evaluated costs, since the equivalent capacity (the denominator in the determination of the evaluated costs) is higher with consideration of losses.

The conditions under which distributed generation would be needed and *able* to operate differ; before, during and after the Leaside TS upgrade.

Timeframe	DG Operating Scenario	Rationale
Prior to Leaside Construction	• DG does not operate, except for system emergencies • Some DG may be able to operate, but only where fault currents are not a factor	• DG not needed for system support. Could provide support for emergencies • Fault current contribution may exceed THES & Leaside limits
During Leaside Construction	• DG only operates following an outage at Leaside (or other critical locations) • DG must start and operate during peak demand periods until the problem is corrected and system restored	• DG needed for system support after an outage occurs (system operates in island mode) • DG may need to be started and controlled remotely
After Leaside Upgrade is Completed	• DG operation no longer restricted, except where THES fault current limits exceeded • DG may be needed for transmission support if new supply is deferred	• Fault current limits at Leaside no longer limits DG operation • New transmission supply *may* be deferred one or more years if enough DG is installed

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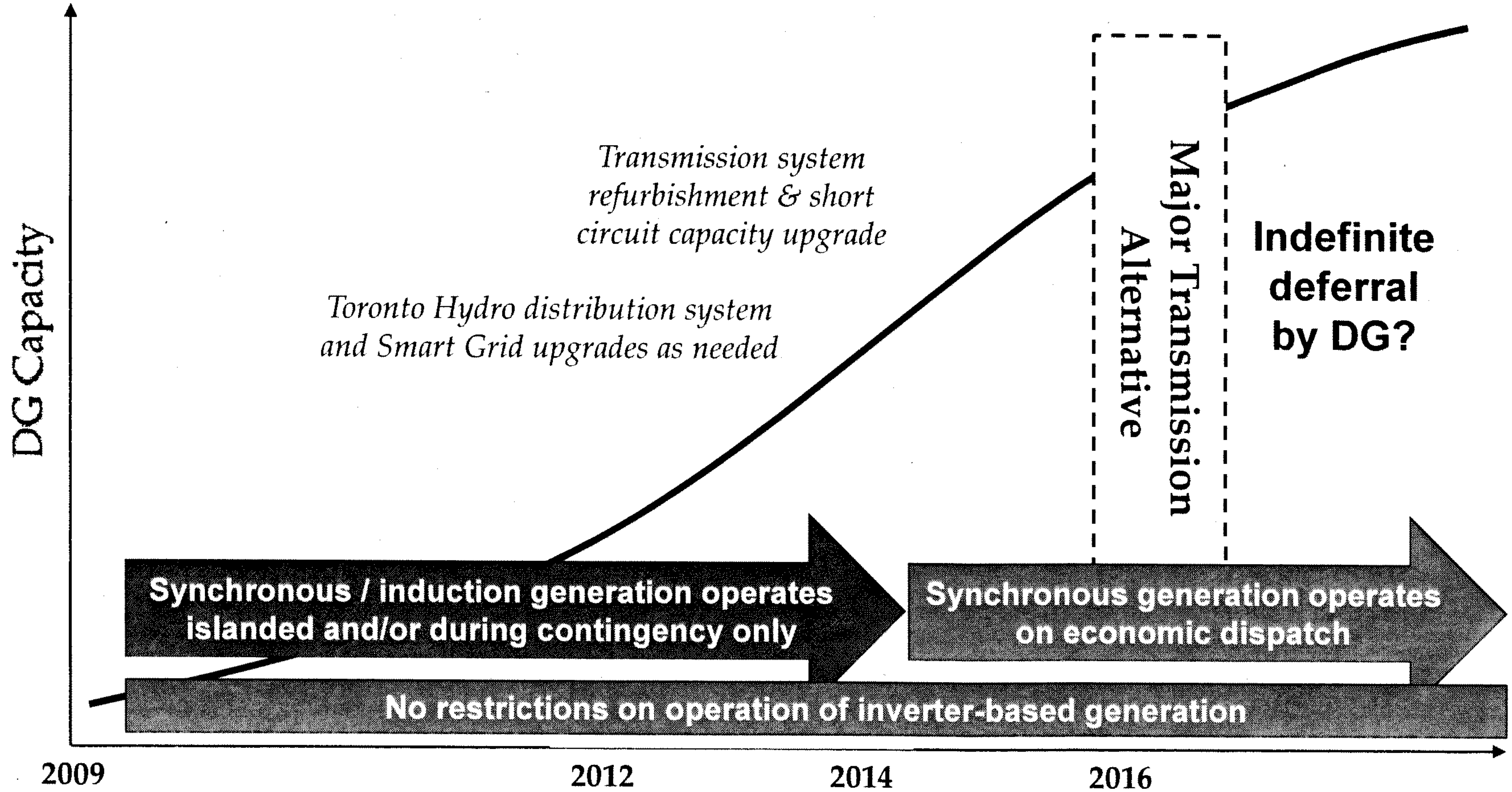
Possible DG acquisition / operation scenario in areas of Central and Downtown Toronto after existing short-circuit capacity (~ 20 MW of synchronous DG on Leaside TS and ~ 60 MW on Manby TS is reached)



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IPSP

By 2012:

- most station facilities will be over 40 years old;
- many underground cables will be over 50 years old; and
- most of the overhead circuits will be over 60 years old.

Loading levels in the Leaside system are very high and near capacity. PEC will provide some near-term relief, but as indicated, capacity issues can occur as early as 2016. While Conservation is expected to offset much of the load growth and keep loading levels below equipment limits, such loading levels will continue to be high over the next 20 years. There is very little buffer in the operating time frame to handle unexpected events beyond normal criteria events.

High loading levels also restrict both the number and duration of outages that can be managed. Outages are limited mainly to off-peak and some shoulder-peak periods. Refurbishment of cables and significant portions of the 115 kV stations will require outages for long durations. At high loading levels and with the number of facilities needing refurbishment over the period 2012 to 2017, Hydro One has indicated in its report that it may not be possible to schedule the necessary work while still providing an uninterrupted supply to customer load. Downtown Toronto customers will be at greater risk of interruptions due to lower supply reliability during extensive equipment outage periods and to higher equipment failure rates if timely refurbishment cannot be done. Figure 1 of Hydro One's report also shows an approximate timeline for a number of cable and line refurbishments or replacements over the next twelve years. Major work on key circuits between Hearn and Leaside, such as C5E/C7E and H1L/H3L, will constrain the output of PEC which may be needed to support the local system when there are outages.

Increased transmission capacity that can provide back up supply when significant facilities are out for long periods will greatly mitigate interruption risks. However, because of the inherent system design and equipment limitations, significant new capacity at Manby and Leaside cannot be effectively provided. There are short circuit limitations at the Manby,

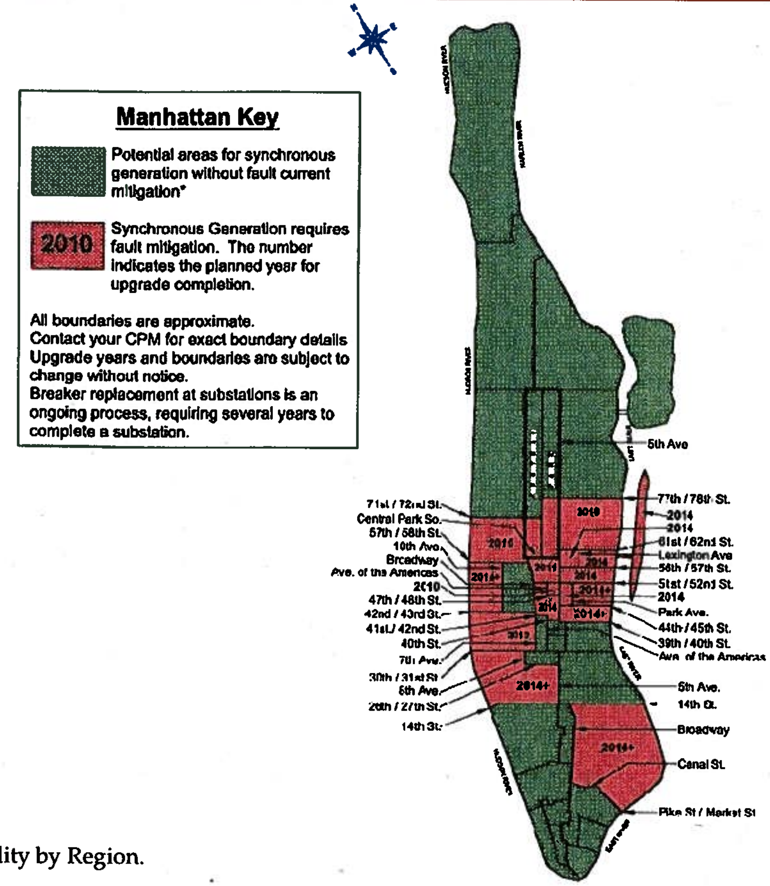
Further, the estimates of the technical potential for DG assume an unconstrained distribution system.

- In its current state, the Toronto Hydro distribution system has certain short-circuit issues that impede the installation of certain DG potential, i.e., synchronous generation.
- Estimates developed herein do not account for these limitations, and hence an unconstrained system assumption.

Con Edison has identified areas where fault current limits preclude synchronous generation.

- Con Edison has instituted formal plans to upgrade substation equipment to mitigate fault current limits, which will enable installation synchronous DG in Manhattan and other boroughs
- On the map at right, areas in shown in red require fault mitigation.
  - Synchronous generation is prohibited at the grid network level (208/120 volt) level.
  - DC, inverter-based (includes fuel cells, micro-turbines, and PV) and induction generation may be installed across all areas of Manhattan.
- Some 450 MW of load exists across the Downtown Toronto area on a secondary grid system, where synchronous generation is also prohibited.
- The Con Edison synchronous generator exclusion applies explicitly to secondary grid networks, not to spot networks, which can better accommodate larger generators and typically have high-rise buildings connected to them.
  - Approval to connect synchronous DG on spot networks is likely on a case-by-case basis, recognizing that some generators will be too large and/or cause network performance problems.

Fault Current Map for Manhattan[1]



Source: 1. Con Ed Interconnection Requirements – Synchronous Generation Placement Availability by Region. http://m020-w5.coned.com/dg/images/maps/m.pdf

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INTERROGATORIES OF POLLUTION PROBE

INTERROGATORY 4:

Reference(s): **none**

a) Please provide City of Toronto street maps that clearly show the boundaries for each area in Toronto where there are Toronto Hydro distribution system constraints that limit the amount of natural gas-fired combined heat and power (CHP) generation capacity that can be attached to Toronto Hydro's distribution system.

b) For each constrained area, please state the maximum quantity (MW) of natural gas-fired CHP that can currently be added to the Toronto Hydro distribution system in that area.

c) For each constrained area, please describe in detail Toronto Hydro's proposed actions and budgets to reduce these constraints in that area.

d) For each constrained area, please state the maximum quantity of natural gas-fired CHP that will be able to be added to the Toronto Hydro distribution system in that area by:

   i. December 31, 2010;
   ii. December 31, 2011;
   iii. December 31, 2012;
   iv. December 31, 2013;
   v. December 31, 2014; and
   vi. December 31, 2015.

RESPONSE:

a) The distribution system has limits to generation as it has limits to the loads it serves. Just as it is not possible to set a specific limit for residential load customers separately from consideration of the total load limit of all customers served from a

INTERROGATORIES OF POLLUTION PROBE

station/feeder, so it is not possible to set the limit for natural gas-fired generation separately from the limit of all generation sources on a station/feeder. The limits of all generation sources are not available on a City street basis. The question cannot be answered with reasonable effort within the required timeframe.

THESL is actively working on determining the limits to generation in a manner that will comply with the Regulations of the Green Energy Act. The results will be published and updated regularly on THESL's website, www.torontohydro.com. This will assist all project proponents, both renewable and non-renewable in finding suitable sites for their facilities. The reporting method, set out in the Regulations, will provide the information on a station bus and feeder level instead of on a street basis. This method will be used by all electric utilities in Ontario and is superior to a map based report for urban utilities as urban utilities frequently have multiple feeders (each with its own limits) on the same street.

b) Please see the reply to a)

c) Please see the reply to a)

d) Please see the reply to a)

INTERROGATORIES OF POLLUTION PROBE

INTERROGATORY 5:

Reference(s): none

Please provide detailed estimates and breakdowns of all of the additional costs required to connect the following proposed CHP facilities to Toronto Hydro's distribution system:

a) total of 5.7 MW of CHP at Sunnybrook Hospital;
b) total of 20 MW of CHP located on the site of the Toronto General Hospital's parking garage on Elizabeth Street;
c) total of 6 MW of CHP at the north-east corner of Victoria and Queen Streets; and
d) total of 6 MW of CHP at 246 & 252 Sackville Street.

If some of these costs would be covered by planned infrastructure/capital improvements, please note that as appropriate as well as when these improvements are expected to be implemented.

RESPONSE:

The analysis cannot be conducted based on the information provided and in any case could not be completed with reasonable effort within the required timeline.

Market penetration estimates have been developed based on expected customer willingness to install DG at various "price" points

- Utilized a payback acceptance-based methodology to estimate market penetration in the medium and long term
  - Simple payback = time period necessary to recover investment (eg, if invest $2 million and "save" $500,000 per year, payback = 4 years)
  - Through several prior studies, Navigant Consulting has found that simple payback acceptance is the most valid metric to assess market penetration.
- The payback acceptance concept focuses on customer (versus generation developer) role in DG decision
- Market penetration becomes a function of "price" paid to build and operate generator which is directly related to NRR
  - Non-commodity cost savings and other load displacement benefits (eg, reduced transmission and distribution charges, provincial benefit, etc.) are not yet been reflected in analysis – would improve payback if included
- Estimate does not reflect any system constraints.
- Market penetration for DG likely lies between 140 and 550 MW; however, overlapping capacity exists at these levels.

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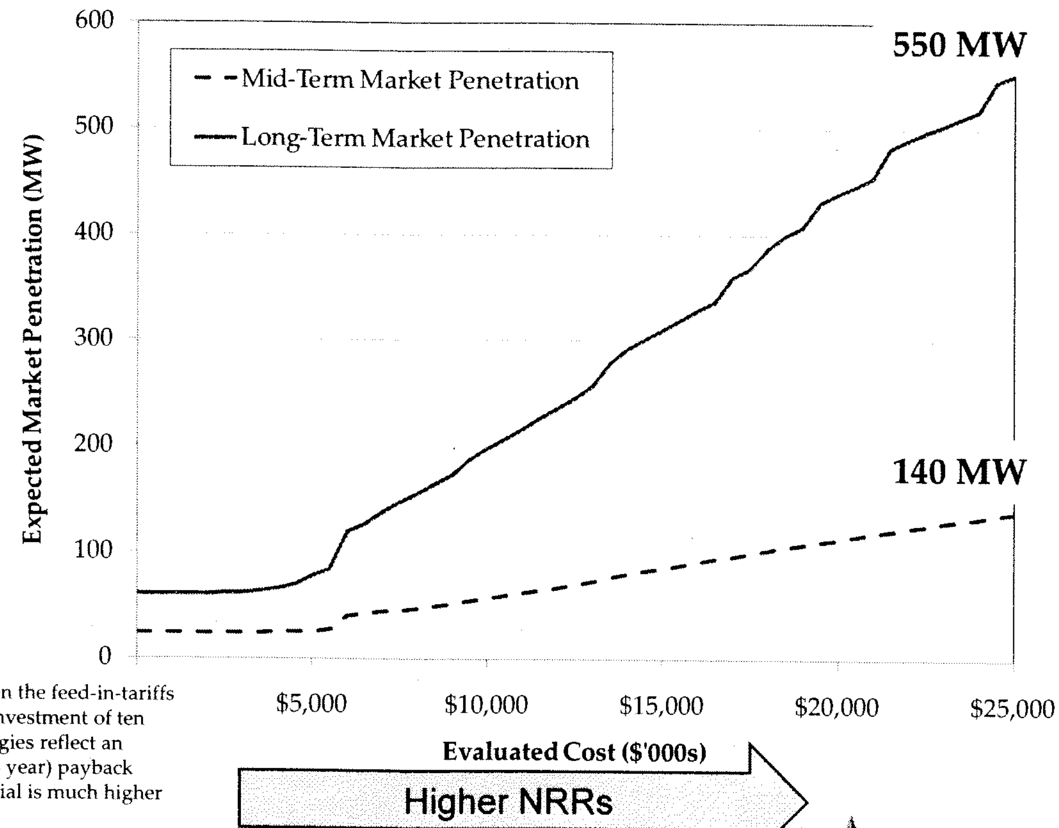
Estimate for DG penetration in the medium (~5 years) term is ~ 140 MW based on payback acceptance modeling.

- The medium-term market penetration estimate provides a base on any expectations for DG.
- Given extremely high evaluated costs and correspondingly low payback periods, the development of an appropriate contract/payment structure becomes increasingly important.

Expected Mid- and Long-Term DG Market Penetration



NB: The penetration rate for non-residential and residential PV is based on the feed-in-tariffs as proposed by the government, which provide a payback on the initial investment of ten years or more. Conversely, the penetration rates for the non-PV technologies reflect an assumed payment structure to customers that yields very short (eg, 2 to 4 year) payback period so the expected penetration as a percentage of the technical potential is much higher than for the PV technologies

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The economic analysis of DG is based on an evaluated cost approach and provides a comparison of cost to peaking SCGT capacity.

- Evaluated costs for the range of DG technologies considered in this study range from less than $1 million/MW to $24 million/MW for diesel SCR upgrade costs and residential PV, respectively.
- A number of major potential benefits serve to narrow the cost difference between DG, which traditionally, is viewed as more "expensive" than central plant generation.
- Major potential benefits considered, include the impact of:
  - Deferral of any major transmission system upgrade;
  - Deferral of 115 kV transformer stations;
  - Deferral of Toronto Hydro capacity upgrades; and,
  - Adjustments to reflect transmission and distribution system losses.
- DG projects including large CHP, small, medium, and large gas engine capacity, and all upgraded diesel backup generation are likely to be cost competitive with peaking plant generation after major benefits are accounted for.

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On an evaluated cost basis, evaluated costs range from $1.5 - $24 million/MW with costs for small-scale PV expectedly at the high end.

- An estimate of the evaluated cost for a typical SCGT peaking plant was developed to provide a reference against DG
  - Estimate of typical SCGT evaluated cost totals $1.8 million/MW.
- At $2.7 million/MW, large gas engines (5-10 MW) come in at the low end of the evaluated cost distribution for DG technologies.
- On the CHP side, the evaluated cost of large CHP projects equals $3.7 million/MW.
- Given their high capital costs, evaluated costs for residential and non-residential PV top $20 million/MW.
  - A PPA-based output profile was used to determine the evaluated cost of PV.
  - PV capacity was based on output during period from noon to 5pm
  - PPA prices were 80.2 c/kWh for residential PV, and between 53-80 c/kWh for commercial/industrial rooftop PV as per the government's proposed Feed-In Tariff.

Evaluated Cost and Potential by Generator

Project Type	Technical Potential (MW)	Evaluated Cost ($'000/MW)
Smallest CHP	170	$6,780
Small CHP	90	$5,055
Medium CHP	230	$4,524
Large CHP	150	$3,728
Smallest Gas Engine	60	$4,621
Small Gas Engine	40	$3,565
Medium Gas Engine	60	$3,211
Large Gas Engine	20	$2,681
Micro-CHP	210	$13,385
Typical SCGT	393	$1,500
Residential PV	300	$23,708
PV (<= 10 kW)	30	$23,708
PV (10 – 100 kW)	200	$20,780
PV (100 – 500 kW)	190	$18,214
PV (> 500 kW)	640	$15,055
Large Fuel Cell CHP	150	$7,414

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Each of the major potential benefits level the evaluated cost of any DG to comparable central plant generation.

- Navigant Consulting estimates of the potential benefits from capacity upgrades and losses are shown below:

Potential Benefit	Expected Range		Comment
	Low	High	
Deferral of major transmission upgrade ($/MW)	$400,000	$1,300,000	Depends on 1) extent to which distributed generation can support other transmission upgrade requirements (infrastructure renewal and mitigation of high impact events); and 2) relative "cost" of satisfying these requirements through transmission upgrade
Deferral of 115 kV station upgrade ($/MW)	$0	$50,000	Depends on extent to which costs of enabling distributed generation offset capacity upgrade deferral value
Deferral of Toronto Hydro capacity upgrade ($/MW)	$0	$50,000	Depends on extent to which costs of enabling distributed generation offset capacity upgrade deferral value
Adjustment to reflect losses	-4%	-8%	Treat as a downward adjustment in evaluated costs of distributed generation. Will depend on location-specific losses given unique system configuration in Central and Downtown Toronto

- Propose to treat these as unique benefits of distributed generation relative to central plant (consistent with treatment of similar benefits in conservation and demand management benefit / cost analysis). Alternative treatment would consider capacity upgrades as costs associated with central plant; would not affect resultant net benefits or net costs of distributed generation

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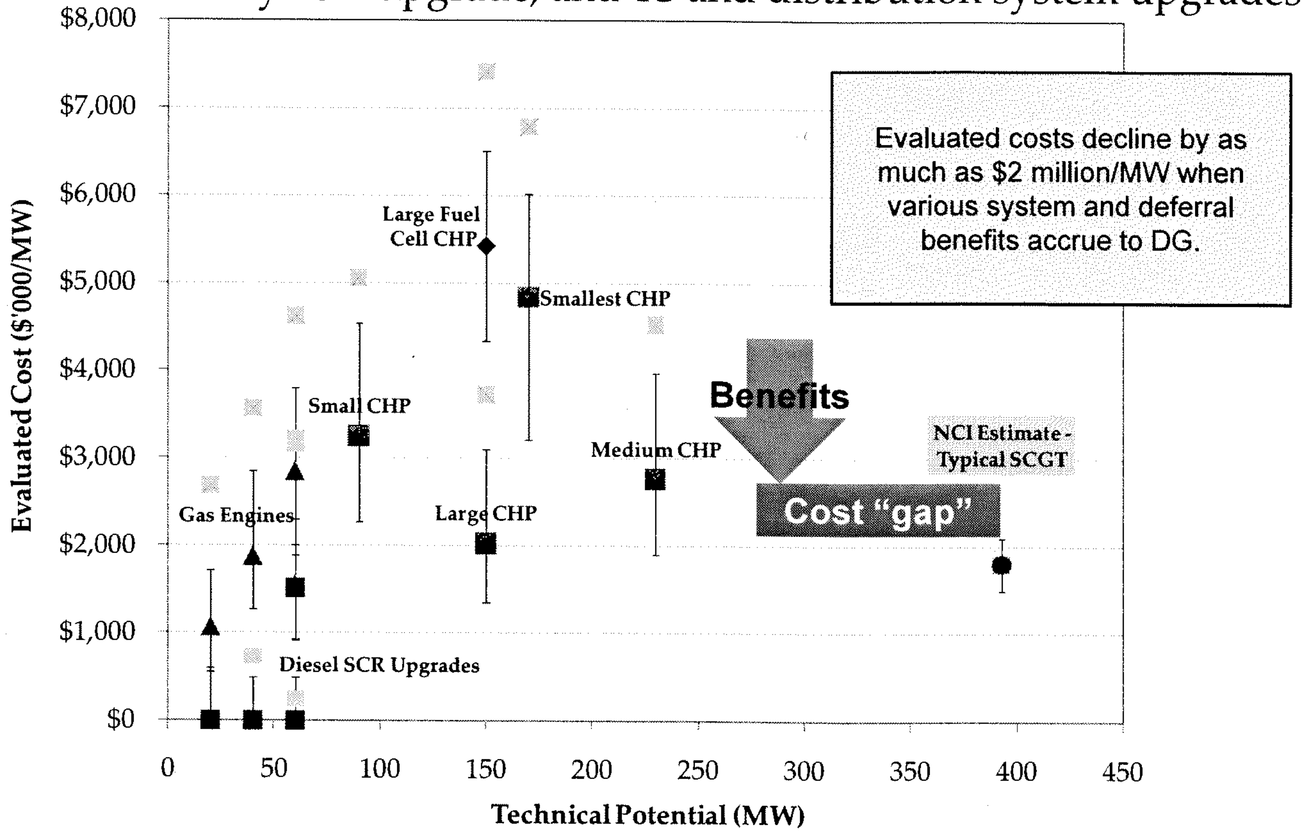
These other potential benefits could narrow the cost "gap" between DG and central plant peaking capacity.

- The economics of DG improve considerably under the most favourable assumptions regarding these other benefits (ie, accounting for avoided losses of 8%, the deferral value of a major transmission system upgrade, and TS and distribution system upgrades.



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INTERROGATORIES OF POLLUTION PROBE

INTERROGATORY 3:

Reference(s): Exhibit Q1, Tab 4, Schedule 1-3

Page 116 of Schedule 1-3 includes a graph showing the evaluated costs of various distributed generation technologies. However, according to pages 108 and 110, the costs for the various CHP technologies appear to be calculated based on the assumption that they would not be properly sized to match their minimum thermal loads. Please re-calculate these costs and reproduce the graph on page 116 assuming that the CHP technologies are instead properly sized to meet their minimum thermal loads. Please provide all of the key input assumptions for your revised cost calculations for each of the CHP technologies.

RESPONSE:

Neither Navigant Consulting nor THESL accept the premise of Pollution Probe's question, which is that the units in question are not properly sized for purposes of the analysis.

The sizing assumptions for the CHP technologies are given on page 81 of the report provided in Exhibit Q1, Tab 4, Schedule 1-3. The thermal energy duration curves for four buildings provided on this page were used to inform Navigant Consulting's sizing assumptions. Both the sizing and cost methodology were presented to industry stakeholder groups in workshops conducted by Navigant Consulting in Toronto on February 25, 2009 and April 17, 2009.

Board Direction from January 22, 2010 Decision on Motion & Procedural Order No. 5, page 6:

INTERROGATORIES OF POLLUTION PROBE

> "The Board directs Toronto Hydro to require Navigant to re-calculate and re-graph the CHP's evaluated costs on the basis of the assumption change described by Pollution Probe in its interrogatory and motion materials."

As stated previously, the sizing assumptions for the CHP technologies are given on page 81 of the report provided in Exhibit Q1, Tab 4, Schedule 1-3. Both the sizing and cost methodology were presented to industry stakeholder groups in workshops conducted by Navigant in Toronto on February 25, 2009 and April 17, 2009. The CHP technologies are appropriately sized to reflect typical building characteristics and the heat rates used in the study reflect typical seasonal changes in thermal demand.

Neither Navigant nor THESL accept the premise of Pollution Probe's question, which is that the units in question are not properly sized for purposes of the analysis. Pollution Probe has not provided any further information as to specific faults in the analysis or what the "properly sized" units would be.

As requested by Toronto Hydro in response to the Board's Decision on Motion & Procedural Order No. 5, Navigant Consulting has recalculated the evaluated costs for the various CHP facility sizes assuming that the facilities are able to achieve a uniform year-round heat rate of 5,766 Btu/kWh. Based on this assumption, the inputs for the re-calculation are provided below. Note that only the heat rates for seasons 2 and 3 for the four CHP technologies have been changed from the similar table in the report.

INTERROGATORIES OF POLLUTION PROBE

	Units / Season	Large CHP	Medium CHP	Small CHP	Smallest CHP
Overnight Capital Cost	($2008/kW)	$2,500	$2,900	$3,200	$4,000
Fixed O&M (installed)	($/kW-yr)	$125	$147	$162	$200
Variable O&M	($/MWh)	$8	$8	$8	$8
Heat Rate HHV by Season(Btu/kWh)	1	5,766	5,766	5,766	5,766
	2	5,766	5,766	5,766	5,766
	3	5,766	5,766	5,766	5,766
	4	5,766	5,766	5,766	5,766
Nameplate Capacity	(kW, MW)	5-10 MW	1-5 MW	500kW-1 MW	100-500 kW
Total NRR (Fixed + Indexed)	2008 $/kW-year	$399	$469	$516	$638
Monthly NRR	2008 $/kW-month	$33	$39	$43	$53

The recalculated evaluated costs based on the above assumed heat rates are provided in the following table. Note that technical potential in the following table remains unchanged given the "*all other things equal*" basis for this analysis.

INTERROGATORIES OF POLLUTION PROBE

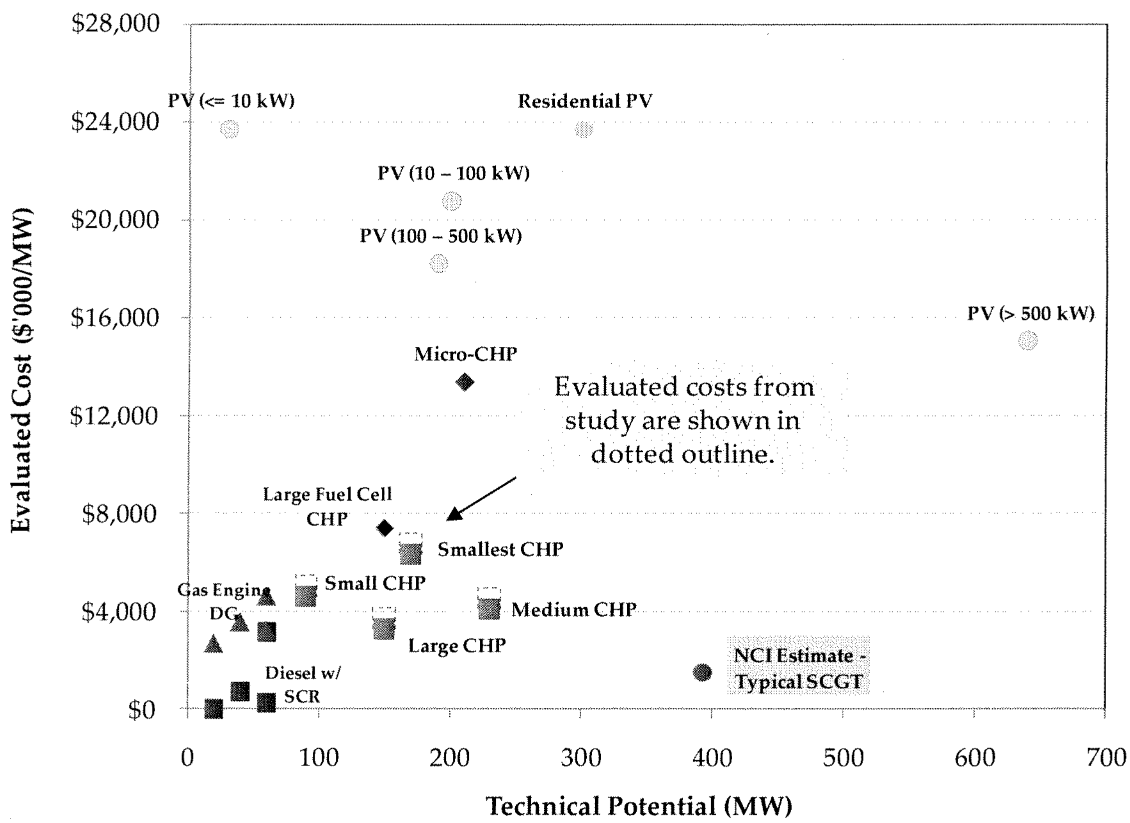
Evaluated Cost and Potential by Generator

Project Type	Technical Potential (MW)	Evaluated Cost from Study ($'000/MW)	Recalculated Evaluated Cost ($'000/MW)
Smallest CHP	170	$6,780	$6,352
Small CHP	90	$5,055	$4,627
Medium CHP	230	$4,524	$4,096
Large CHP	150	$3,728	$3,300

As shown, the evaluated costs assuming that a 5,766 Btu/kWh heat rate can be achieved year-round are approximately $430,000 / MW less than indicated on page 113 of Exhibit Q1, Tab 4, Schedule 1-3.

The chart given on page 116 of Exhibit Q1, Tab 4, Schedule 1-3 has been reproduced below with the recalculated evaluated costs from the above table.

INTERROGATORIES OF POLLUTION PROBE



Although the technical potential for each of the four CHP technologies has not been changed in the above table and chart, Navigant Consulting notes that only a portion of facilities in Toronto are likely to have a seasonal thermal demand profile that would allow CHP to operate year-round at a heat rate in the range of 5,766 Btu/kWh. Hence, the technical potential for such CHP facilities to operate year-round at a heat rate in the range of 5,766 Btu/kWh would be less than was indicated in Exhibit Q1, Tab 4, Schedule 1-3, p. 113. Furthermore, some of these facilities would likely require a smaller CHP facility (as a percentage of peak thermal demand) in order to achieve a year-round heat rate in the range of 5,766 Btu/kWh. To the extent that the CHP facility size is reduced,

INTERROGATORIES OF POLLUTION PROBE

the unit capital cost (expressed on a $ per MW basis) is likely to increase, which will increase the evaluated costs. The net effect of these considerations would be lower technical potential and higher evaluated costs than shown in the chart above.

To reiterate, Navigant Consulting believes the CHP facilities as presented in the study are appropriately sized for the purposes of the analysis undertaken.

The table below summarizes those detailed capital cost and operating characteristics, where applicable, for each DG technology.

Detailed Operating and Financial Assumptions by Project

	Units / Season	Large CHP	Medium CHP	Small CHP	Smallest CHP	Large Gas Engine	Medium Gas Engine	Small Gas Engine	Smallest Gas Engine	Fuel Cell	Micro-CHP
Overnight Capital Cost	($2008/kW)	$2,500	$2,900	$3,200	$4,000	$1,700	$2,000	$2,200	$2,800	$4,500	$8,300
Fixed O&M (installed)	($/kW-yr)	$125	$147	$162	$200	$85	$100	$110	$110	$225	$415
Variable O&M	($/MWh)	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8
Heat Rate HHV by Season(Btu/kWh)	1	5,766	5,766	5,766	5,766	9,100	9,100	9,100	9,100	5,500	5,600
	2	9,100	9,100	9,100	9,100					8,000	11,100
	3	9,100	9,100	9,100	9,100					8,000	11,100
	4	5,766	5,766	5,766	5,766					5,500	5,600
Nameplate Capacity	(kW, MW)	5-10 MW	1-5 MW	500kW-1 MW	100-500 kW	5-10 MW	1-5 MW	500kW-1 MW	100-500 kW	100kw-10MW	1.8 kW

Note: Project heat rates vary by season (as defined in the OPA's CHP II Contract) for those CHP-based DG projects as Winter heating requirements include a boiler offset, based on technical project specifications. See Appendix B for detailed calculation.

NAVIGANT CONSULTING

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0680

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

AND IN THE MATTER OF an application by Toronto Hydro-Electric System Limited for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2008, May 1, 2009, and May 1, 2010.

BEFORE: Paul Sommerville
Presiding Member

Paul Vlahos
Member

David Balsillie
Member

DECISION

May 15, 2008

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initiative in January 2008 to better understand this issue. In the Board's view it would not be appropriate for the Board to direct a different regulatory treatment for the Applicant than for the sector as a whole by eliminating the provision for a true-up. Moreover, while there is always room for improvement in this area, the Applicant's line losses do not appear to be excessive. The Board does not accept Pollution Probe's proposal and accepts the Company's provision for line losses at 3.1%.

5.3 Distributed Generation

Currently, virtually all of the electricity for Downtown Toronto is supplied through two transmission lines. Concern about ability to supply Downtown Toronto in the future has caused the OPA to consider a third line, at a capital cost of $600 Million.

Pollution Probe noted that neither the Government of Ontario nor Toronto Hydro support a third line. The solution, according to Pollution Probe, is more distributed generation ("DG").

Pollution Probe noted that 300MW of DG would eliminate the supply problem but acknowledged the Applicant's possible limitations as to the size of installation which could be accommodated on the Applicant's distribution system. Pollution Probe therefore proposed that the embedding of thirty 10MW generators within Toronto would be sufficient to avoid the third line.

Pollution Probe also contended that, along with distributed generation, CDM could further reduce the requirement for this additional supply. Pollution Probe compared the budgets for the CDM ($22Million) and Supply-Side Infrastructure ($906Million) programs, inferring a lack of strong commitment to CDM by the Applicant.

The Applicant asserted that the issue of whether or not there should be new transmission supply to Toronto is a transmission issue that should be addressed elsewhere, such as in the IPSP proceeding currently before the Board. It also suggested that issues concerning distributed generation, transmission and distribution cost responsibility and rate design are being reviewed by the Board at this time in other generic proceedings.

The Applicant contended that possible solutions examined include connections for DG and self-generation, but that these must make sense from engineering, economic and regulatory perspectives. For example, DG customers are required to fully fund connections to the network since they do not currently pay distribution or use-of-system charges if they do not take load. This system protects load ratepayers from subsidizing the costs for distributed generators to connect to the Applicant's system.

Board Findings

Leaving aside the question of the need for the third transmission line, which the Board acknowledges is best addressed through other proceedings, including the IPSP application currently before the Board, the Board considers that the Applicant should facilitate connections for DG and self-generation, where they can be implemented practically and economically, both from the perspective of the generator and of the Applicant and its load customers.

With regard to conservation and demand management, it would be premature for the Board to comment on the specific suggestions made by Pollution Probe, as the IPSP proceeding has not yet been completed.

The Board observes that the Applicant's study of distributed generation has not been rigorous. Therefore, the Board directs the Applicant to conduct a study into the capability, costs and benefits of incorporating into the Applicant system, a significant (up to 300MW) component of bi-directional distributed generation in Toronto. In this study, the Applicant should also incorporate the outcomes, as they pertain to distributed generation, of two items which are currently being considered by the Board: 1) enabler lines and their connection costs; and 2) the IPSP. The study should also be responsive to any new policy or regulatory developments in these areas. This study shall be filed as part of the Company's next application dealing with rates beyond the test period dealt with in this proceeding.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2009-0139

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

AND IN THE MATTER OF an application by Toronto Hydro-Electric System Limited for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2010.

ISSUES LIST DECISION and PROCEDURAL ORDER NO. 2

Toronto Hydro-Electric System Limited ("Toronto Hydro", the "Company" or the "Applicant") filed an application, dated August 28, 2009, with the Ontario Energy Board under section 78 of the *Ontario Energy Board Act, S.O. 1998*, c.15, Schedule B, seeking approval for changes to the rates that Toronto Hydro charges for electricity distribution, to be effective May 1, 2010.

The Board issued a Notice of Application and Hearing dated September 16, 2009. In Procedural Order No.1, issued on October 19, 2009, the Board approved 10 intervention requests.

Issues List Decision

Procedural Order No. 1 contained a draft issues list. Submissions on the draft issues list were received from the following parties:

Vulnerable Energy Consumers Coalition ("VECC")
Association of Major Power Consumers in Ontario ("AMPCO")
Consumers Council of Canada ("CCC")
Pollution Probe ("PP")
School Energy Coalition ("SEC")
Canadian Union of Public Employees, Local One ("CUPE One")
Building Owners and Managers Association of the Greater Toronto Area ("BOMA")
Smart Sub-metering Working Group ("SSWG")

Toronto Hydro provided two submissions, dated October 26, 2009 and October 30, 2009, respectively.

The Board has considered all submissions in establishing a final issues list which is attached as Appendix A. The parties were generally satisfied with the draft issues list, however several changes and clarifications were requested. These are reviewed below along with the Board's rationale in addressing each of these requests.

1. GENERAL

1.1 Has Toronto Hydro responded appropriately to all relevant Board directions from previous proceedings?

1.2 Are Toronto Hydro's economic and business planning assumptions for 2010 appropriate?

1.3 Is service quality, based on the OEB specified performance indicators, acceptable?

1.4 Is the overall increase in the 2010 revenue requirement reasonable given the impact on consumers?

Pollution Probe stated that it supported proposed Issue 1.1 in light of the distributed generation study previously required by the Board. Pollution Probe also proposed two new additional issues related to distributed generation and combined heat and power ("CHP") implementation. The first of these issues was: "Are Toronto Hydro's proposed programmes and budgets to reduce its distribution system constraints to the installation of distributed generation appropriate?"

Pollution Probe argued that this additional issue should be included as it was one of the next logical steps as a result of the Board's previous direction, Toronto Hydro's responding studies, and other recent developments.

Pollution Probe stated that in the alternative to placing this issue on the Issues List, if the Board was of the view that this proposed issue is covered by other issues on the Issues List, it would accept a clear statement by the Board to that effect in lieu of placing this issue on the issues list.

Toronto Hydro opposed the inclusion of this issue, arguing that the Board's issue no. 1 was appropriate and covered Pollution Probe's theme of being permitted to ask questions about Toronto Hydro's pre-filed study on distributed generation. Toronto Hydro also stated that Pollution Probe and others were entitled to ask Toronto Hydro about proposed 2010 budget expenditures in connection with distributed generation.

The Board finds that it is unnecessary to place this issue on the Issues List. The Board is of the view that this issue is subsumed under issue 1.1. Pollution Probe and other parties may raise questions and issues related to distributed generation, legitimately arising from the distributed generation report filed by Toronto Hydro in the present application in compliance with the requirement of the Board in its EB-2007-0680 Decision.

The second issue proposed by Pollution Probe was: "Should Toronto Hydro's policies with respect to recovering its costs of adding CHP generation to its distribution grid be amended to encourage the development of CHP?"

Pollution Probe argued that this additional issue was another logical step as a result of the Board's previous direction and Toronto Hydro's responding studies regarding distributed generation. Pollution Probe added that a key practical question arising as a result is who should pay for the costs of connecting CHP to Toronto Hydro's distribution system.

Pollution Probe stated that, as with the first issue, in the alternative to placing this issue on the Issues List, if the Board was of the view that this proposed issue is covered by other issues on the Issues List, it would accept a clear statement by the Board to that effect in lieu of placing this issue on the issues list.

Toronto Hydro objected to the inclusion of this proposed issue on the grounds that it presupposes a policy change of the Province of Ontario which did not exist to its knowledge, and otherwise constituted a generic issue for the broader Ontario electricity sector.

The Board finds that it is unnecessary to place this issue on the Issues List. The Board is of the view that to the extent that there are issues identified in the distributed generation report that pertain to barriers to distributed generation connection this issue is also subsumed under issue 1.1 of the Final Issues List and that Pollution Probe and other parties may ask questions related to CHP which legitimately arise from Toronto Hydro's filed distributed generation report.

2. LOAD and REVENUE FORECAST

2.1 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

2.2 Is the proposed amount for 2009 other revenues appropriate?

Toronto Hydro proposed that in Issue 2.2, "2009" should be replaced with "2010". The Board accepts this change.

Pollution Probe proposed that a new issue be added to the Issues List, which was "Are Toronto Hydro's proposed CDM programmes and budgets appropriate?"

Pollution Probe submitted that it was important for the Board to know what CDM is being done now and whether more should be done, particularly in light of various recent developments such as the passage of the *Green Energy and Green Economy Act, 2009.*

Pollution Probe further argued that the fact the OPA may fund some or all of the CDM programs does not determine or preclude the Board's review of a distributor's CDM programs to ensure that they are appropriate and that it is the Board's fundamental role