Consumers Council of Canada (CCC) INTERROGATORY #5 List 2

Interrogatory

Ref: A/T13/S1

Issue Number 1.4
Issue: Is Hydro One's proposal to establish a revenue requirement beyond the 2007 and 2008 test years appropriate?

Was the specific proposal that is being put forward for rate adjustments beyond 2007 and 2008 subject to stakeholder consultation? If so, please indicate the nature of that consultation. If not, why not?

Response

The specific proposal for revenue requirement (not rate) adjustments that is included in Hydro One's pre-filed evidence was not subject to stakeholder consultation. However, Hydro One did put forward the preliminary concepts of the need for adjustment mechanisms at the third stakeholder consultation session which was held on July 5, 2006[1]. At that time Hydro One had not yet fully developed its proposal and the associated details but it wanted to share the ideas and invite stakeholder response. Hydro One noted at that meeting that the driver behind the proposal was to manage the significant transmission investments that will be needed during this period, and advised stakeholders that it would file the proposed plan with details that were going to be developed after the stakeholder meeting. The discussion that took place on this subject matter at the said meeting is summarized on pages 14-16 of the notes of the meeting, which are Attachment A.

[1] Exhibit A, Tab 16, Schedule 1, page 10, line 27.

Stakeholder Consultation
2007/2008 Transmission Rate Application

Stakeholder Session #3
Meeting Notes

Metropolitan Hotel
Toronto Ballroom, 2nd Floor
108 Chestnut Street
Toronto, Ontario

July 5 & 6, 2006

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1.0 BACKGROUND

Hydro One has begun to prepare an application to the Ontario Energy Board (OEB) for the approval of its 2007 and 2008 Revenue Requirement and Cost Allocation / Rate Design for its Transmission business. Hydro One Transmission rates for the 2006 rate period are subject to an earnings-sharing mechanism, which will be based on the 2006 audited financial statements of the company. These audited financial statements will not be available until the first quarter of 2007 and will be dealt with in the appropriate time period. The 2007/2008 Transmission Rate Application will consider the public interest as well as the cost for transmission service that is forecast to be incurred by Hydro One. The company has sought input from customers, intervenors and other stakeholders before submissions are made to the OEB on Transmission Rates in the fall of 2006.

On May 3, 2006, Hydro One initiated a stakeholder consultation program to assist in the development of this application and to facilitate improved regulatory efficiency and a successful outcome. Three stakeholder sessions were held between early May and July 2006. The main objectives of the consultation program were to:

- Create better stakeholder understanding of the Hydro One transmission business, cost structure, system development challenges and costing, cost/reliability trade-offs and equity/user-pay considerations;
- Ensure stakeholder concerns and views are identified, understood and considered in the decision-making for the Hydro One Transmission application;
- Provide insight, advice, and feedback to Hydro One on any concerns, values, information and preferences regarding all aspects of Hydro One's transmission application and operations;
- Act as a forum for the exchange of information and views;
- Assist Hydro One to anticipate and respond to stakeholder and customer views and preferences;
- Clarify as many issues as possible prior to the Hydro One submission to the OEB;
- Scope the transmission issues to be heard by the OEB; and
- Reduce the time and cost of the regulatory process associated with the 2007 / 2008 Transmission Rate Application.

Hydro One sought to develop with stakeholders a shared understanding and prioritization of the key issues affecting the application. Feedback from stakeholders guided the issues discussed and information provided during the consultation forums and in the application exhibits. Hydro One aimed to resolve or reduce the scope of as many issues as possible prior to the OEB process. Hydro One believes that open dialogue was an essential component to this process. All consultations were carried out on a without prejudice basis.

Hydro One invited key stakeholders who took part in previous Hydro One Networks distribution rate proceedings, as well as large transmission customers, to participate in a series of discussion forums.

The first stakeholder session took place on May 3rd and 4th, 2006 and the second took place on June 1st and 19th, 2006. This document reports on the third of these stakeholder sessions, which took place on July 5th and 6th, 2006. More details about the consultation process are available at: http://www.hydroonenetworks.com/en/regulatory/2007_transmission_rate_application. Follow the links to the stakeholder consultation program.

1.1 Process Overview

The proposed agenda (Attachment #1) was provided to stakeholders in advance, together with copies of the presentation slides. The session was comprised of a series of presentations followed by interactive group discussion. Participants were also encouraged to ask questions during presentations. At the end of each morning session, stakeholders were given the opportunity to select issues to be discussed in an afternoon session. Appropriate Hydro One staff were called in to provide additional detail if needed.

There were a few changes to the agenda:

- The first part of the Rate Base and Operation, Maintenance & Administration (OM&A) presentation, namely Hydro One Networks Transmission Capital Investments, took place before the morning break on Day 1;
- The presentation on Cost Allocation and Rates took place before the stakeholder selection of afternoon discussion topics on Day 1;
- The presentation on Incentive Regulation was moved from the morning of Day 2 to immediately following lunch on Day 1;
- Stakeholder-selected topics for discussion in the afternoon of Day 1 were:
    - OM&A Shared Services Breakdown;
    - OM&A Asset Class Breakdown;
    - Capital Structure and Return on Equity;
- Issue Discussion #2: Responding to a stakeholder request for information during Day 1, a presentation on the Microwave Replacement Program was given after the Transmission Power Quality presentation on Day 2;
- This was followed by the Summary of Action Items and Responses from Session 2; and
- Stakeholders identified no further issues for discussion on Day 2, so the Session concluded with lunch.

Participants were invited to email additional questions, comments and suggestions to Hydro One via Enza Cancilla (Manager, Public Affairs). They were also asked to complete comment sheets evaluating the stakeholder consultation sessions.

1.2 Welcome and Introductions

The facilitator (Chris Haussmann of Haussmann Consulting Inc./HCI) welcomed participants and thanked them for their attendance. Joe Toneguzzo (Director, Transmission Rate Filing) thanked stakeholders for input, noting that the Transmission rate filing, will benefit greatly from their contribution. Participants then introduced themselves. In attendance were representatives from independent transmission-connected customers, electricity industry load customer Associations, electricity industry generation customer Associations, electricity distribution Associations, local distribution companies (LDCs), consumer and energy advocacy groups, Union Gas, Ontario Power Generation (OPG), the Independent Electricity System Operator (IESO), the OEB, Hydro One and the HCI facilitation team.

The full list of participants is provided in Attachment #2.

2.0 PRESENTATIONS AND DISCUSSION

The following sections provide brief descriptions of the presentations made by Hydro One staff. Questions of clarification and discussion during or following each presentation are summarized in bullet form. Points in *italics* represent responses or comments from Hydro One. Presentation slides are posted at:
http://www.hydroonenetworks.com/en/regulatory/2007_transmission_rate_application. Follow the links to the stakeholder consultation program.

2.1 Revenue Requirement

Greg Van Dusen (Director, Corporate Accounting, Policies & Systems) provided an introductory overview of the revenue requirement, including how it is calculated. He presented information on the customer bill impacts, the rate riders and their respective contributions to the over-all increase, regulatory asset recovery, and the proposed special regulatory treatment of specific generation mix projects. The average 2007 transmission rate increase is 4.3% and the overall bill impact for 2007/2008 is less than 0.5%. The Hydro One board of directors has approved the proposed revenue requirement of approximately $1.3B for each of 2007 and 2008 and the associated rate changes. The filing for the revenue requirement will take place around mid-September. Changes from 2007 to 2008 include increases in the rate base, and a small reduction in the cost of debt reflecting decreasing interest rates.

The key elements in the calculation of the revenue requirement are:

- Capital Structure – Hydro One is proposing a revised capital structure and return on equity based on an expert consultant's study which recommends 56% debt, 40% common equity, 4% preferred equity and an increase in the return on equity (ROE) to 10.5%. Hydro One has accepted these recommendations.

- Total Rate Base;
    - Net Utility Plant (Gross Plant at Cost minus Accumulated Depreciation)
    - Construction Work-In-Progress for certain high-risk projects (a new element included in the rate base);
    - Total Working Capital (Cash Working Capital and Materials & Supplies Inventory).
- Total Cost of Service;
    - OM&A (including capital tax);
    - Depreciation and Amortization – The new depreciation methodology results in a reduction in depreciation costs of $6M in 2007 and $2M in 2008.
- Total Return on Capital;
    - Return (Debt and Equity); and
    - Income Taxes.

Operational cost is one of the main contributors to the overall revenue requirement. For the period 2003 - 2008, the overall escalation in material and labour is about 12% compared to an overall 6%

bottom-line increase in OM&A. The work conducted in this period is driven by requirements to operate and maintain the transmission system within target performance levels in the context of an aging asset base and increased system loading. Main drivers for the expenditures over this period are work on power equipment, protection/control and metering equipment, and work on ancillary systems.

The 2007/2008 increase in OM&A expenses are required to maintain a safe and reliable transmission system. Annual capital expenditures have increased by more than $400M per annum from 2003 to 2008. This is to address asset replacement, refurbishment needs, and investments to increase interconnection capabilities and to meet growing generation and supply needs in the province.

Specific generation mix projects (slide 12) are critical to the province's electricity system. Since Hydro One is assuming the risks associated with these potential projects, it is proposing that development expenditures for these four projects be included in the rate base and that they earn a return in the year the expenditures are incurred.

The following questions were asked/points were clarified in ensuing discussion:

- Are the expenditures listed on slide 12 the full cost of the projects or does the cost extend beyond 2008?

  They do extend beyond 2008. Total capital expenditures associated with the Bruce to Essa Double Circuit 500 kV line are about $585M. For SVCs (Static VAr Compensators) to Replace Voltage support provided by Nanticoke generators, the total is about $52M. For the Hydro Québec Interconnection, the total is about $120M. The Bruce Special Protection System is about $45M. These numbers take into account that we are not capitalizing interest and that there is no allowance for funds used during construction (AFUDC).

- When is the in-service date for the Hydro Québec Interconnection?

  The planned in-service date for the long-term power purchase agreement that is currently being negotiated is 2009.

- Do any projects start before 2007?

  No. However, there has been a small amount of money spent on the Bruce to Essa Double Circuit 500 kV line for some preliminary engineering but we have not started construction yet.

- Are the preliminary engineering costs captured in the 2007 figure noted in slide 12?

  Yes.

- What are the development costs in slide 8?

  These costs involve things like engineering and development standards.

- Are any of these development costs going to turn into generation mix projects?

  No, generally not. We are required to expense costs on projects up to the point where projects have the preferred alternative declared. So these represent the true OM&A operating cost portion, which are distinct from the capital expenditures.

- Is it correct to say that the generation mix projects are highly speculative investments dependent on something else happening? For example, the Bruce to Essa Double Circuit 500 kV line depends on wind generation actually materializing, and the Nanticoke project depends on the Nanticoke Power Generating Station actually being shut down.

  These projects represent the best information available today but they do carry some risk of not materializing. This is why Hydro One wants special treatment for these projects. Even if these specific projects are not needed, other large-scale projects will be undertaken during this time period to support government initiatives (e.g., phasing out coal, and changing the generation mix). These projects also have long time frames so they need to be started now, and we must take some risk in the near term in order that they will be completed and available on time and to avoid bottling in very expensive generation.

- Why is the cost for the Bruce to Essa double circuit 500 kV line $585M? Can you explain how the cost goes from $10M and $9M to $585M?

  The 2007 and 2008 costs involve things like preliminary engineering but no construction. The $585M is the full project cost to the current 2011 target in-service date.

- Why is the Bruce to Essa Double Circuit 500 kV line project necessary?

  There has been a large amount of wind power development in the Bruce Peninsula. Bruce Power will be returning to service Units 1 and 2 at Bruce A. The existing transmission system is not designed to incorporate and transfer this much generation from the area. If the transmission system capability is not increased, transmission congestion in the Bruce Peninsula will result.

- What would be the consequence to Hydro One if these generation mix projects were treated as ordinary utility capital expenditure (CAPEX) projects? That is, with respect to AFUDC, in-service, and the transfer to rate base, bring the project forward for approval to the OEB but the declaration for in-service is done in the normal way.

  In the broader sense, the impact would probably be invisible to customers. Specifically, if we did not have any special rate treatment, Hydro One would lose approximately $35M in the rate base and the associated return in 2007, and approximately $85M in the rate base and associated return for 2008.

  Anyone who builds new generation will get a take-or-pay contract (e.g., Bruce Power, wind power developers) and will know they will be paid as long as they put the generation in place and have the capability to deliver. Those who build transmission get their money only if the project turns out to be needed. So, Hydro One will build the Bruce to Essa Double Circuit 500 kV line to

transmit all the power from Bruce Power and the wind generation. However, what if there are problems associated with the new generation (i.e., if the Bruce nuclear units do not come on-line or wind power is less than expected)?

Transmission companies internationally (e.g., California, New Mexico) would not start expenditures for significant projects unless they know they can recover their investment. These are supply mix investments, not investments to ensure transmission system reliability. We are going to be told that we have to make these investments. We will go for a Section 92. *These projects involve very large amounts of money with long lead times and we do not want to second-guess. It would also help us to borrow the money if we can demonstrate that we have a receptive regulatory environment, which allows recovery for these types of projects.*

In terms of impact, because some of the projects are multi-year, customers at first will not see a lot of impact. But when the full $585M is spent, there will be a big rate increase. Providing staged costs in rate base also will help smooth the rate impact over time.

- In the gas/petroleum pipeline industry, companies get commitment from shippers through an open season process before going to their regulator. This would be a solution for the electricity industry.

  Yes, this is one way of dealing with this. But who would do the bidding in the electricity industry in Ontario? The Province?

- Would there be a significant impact to capital structure/capital requirements if Hydro One had to deal with these specific generation mix projects in the ordinary way?

  There will be a risk impact in terms of the exposure we have as a company. We are going to have a hard time making these large expenditures on spec (e.g., spending the $585M) unless we have some comfort that we are actually going to get cost recovery.

- There is a *Section 92* for the Hydro Québec Interconnection. But would the Bruce to Essa Double Circuit 500 kV line, where you are double-circuiting an existing line, be exempt from needing the *Section 92*?

  It would need a Section 92 *as well, or some other approval. In the case of the Niagara project, we were told to build it, but we did not know if we could recover the investment in the rate base. We need more assurance that we will recover future investments.*

- What is the transmission rate impact for 2008? And on total bill?

  The transmission rate impact is 2.7% in 2008 and 0.2% for the total bill.

- What is the rationale for the change in capital structure/equity?

  We will file a full study that details the rationale. There are many risk drivers in the transmission business. There are huge expenditures for 2007/2008. We need to borrow money at good rates in

an environment characterized by increased risk. This necessitates maintaining a stable and high credit rating. There are risks associated with government re-direction on these projects and projects not deemed to be prudent investments. In the longer term, we have risk associated with transmission by-pass and lost revenues. There is also risk associated with transmission tariffs and problems with how they are designed that may cause us not to earn our budgeted requirements in any given year. Our consultant for this study is Kathy McShane of Foster Associates.

- I am concerned that you may be double counting. Does the risk-adjusted ROE assume acceptance of your unusual treatment approach for these capital projects?

  Yes. Kathy McShane has been informed of this approach and she agreed with the approach and reflected it in her considerations.

- For clarification on the Bruce to Essa Double Circuit 500 kV line, what cost elements do the $10M (2007) and $9M (2008) represent? Are these studies/consultant reports?

  These are costs incurred for preliminary engineering and the detailed information that we need for environmental assessments, and public consultations/approvals.

- So this would be in addition to the cost for salaries of employees?

  Hydro One employees would be involved in the public consultations/approvals processes and their salaries would contribute to those costs. The big costs come in 2009 to 2011, after the approvals are obtained.

- What is the current capital structure?

  The current Board approved capital structure is 36% common equity, 4% preferred equity and 60% debt.

2.2 Transmission Capital Investments

Mike Penstone (Director, System Investment) provided an overview of Hydro One's transmission capital investments. Describing system assets, he noted that Hydro One is one of the largest transmitters in North America in terms of asset base. Most of the assets were built in the 1960s to 1980s. There has been very little construction since then. Construction in the 1990s is a small percentage of spending. From 1999 to 2005, $1.9B was spent in the Development, Sustaining, Operating, and Common & Other categories. Mike described Sustaining capital investments and noted that Microwave System Replacement is a major program. Telecommunications plays a significant role in the system protection and information transfer functions.

Mike explained the difference between network and local area investments, and described the types of activities that would be included in the Integrated Power System Plan (IPSP), which likely will not be approved until 2008. However, decisions for investment need to be made and he provided Hydro One's view on provincial needs.

Summaries and examples of Development, Sustaining and operating capital investments (1999-2005) were presented. Future (2006-2008) capital expenditures were compared to actual (1999-2005).

The following questions were asked/points were clarified in ensuing discussion:

- Does the Bruce Special Protection (Bruce Area Congestion Relief, slide 12) include the addition of capacitors to increase the existing capacity of the line?

  No. There is an additional step that could be taken, namely the addition of series capacitors, but it is up to the OPA to determine whether that is an appropriate stopgap solution. If they direct Hydro One to construct series capacitors, that would be beyond the projects that we have identified so far.

- With respect to the Hydro Quebec interconnection (slide 12), did the Market Design Committee recommend, and did Hydro One build, an interconnection facility on the Ontario side of the border that Hydro Quebec did not duplicate on their side of the border?

  Hydro One has never actually built anything. There was a proposed agreement in place between Hydro One and Quebec Hydro, on the basis of which Section 92 *and environmental approvals were obtained (and these are still valid). However, within the approvals timeframe Hydro Quebec had second thoughts and decided not to proceed. Hydro Quebec is now considering proceeding with the project, provided that a long-term purchase agreement is reached.*

- With respect to the Bruce Area Congestion Relief (slide 12), it was my understanding that prior to 1998, when Bruce A units 1, 3 and 4 were taken out of service, there was sufficient transmission capacity to accommodate all of the power from the Bruce site. The amount of bottled generation was minimal.

  During those years Bruce never operated at maximum potential due to a number of factors. But there was bottled energy, frequently as a result of the severe weather conditions in the area. Also, a considerable amount of energy was used at the heavy water plant that was then operating on the site. And the Bruce generator units have been improved and will produce more power than before they were shut down.

- Are you saying that the required incremental transmission capacity related to Bruce (slide 12) is not just wind-related but also nuclear-related?

  It is prompted by several factors: the reduced load in the Bruce Peninsula that allows more generation to be taken out of the area; the 725 MW of new committed wind generation that has to flow south and cannot be accommodated by the existing transmission system; and, the Bruce nuclear units that are coming back on line once refurbished. The result is that the existing transfer capacity from the Peninsula is less than the installed generation. Another factor causing the congestion in the Bruce area is that the province is now a net importer of electricity.

- Does the Bruce Area Congestion Relief program (slide 12) mean that the existing Bruce Special Protection System will have to be completely reconfigured?

  That is correct. That is why the Bruce Special Protection System was identified in the revenue requirement presentation as a separate line item. We have bottled generation on the Bruce Peninsula and we will not have the transmission built in time to completely alleviate that bottleneck, so we have to take some stopgap measures. The OPA will decide what those measures will be, but we expect that one of them will be the Special Protection System. If we get the necessary approvals and directives, the transmission line will be in place by 2011. We are working closely with the OPA and have a good sense for the direction of their thinking, even though they are not yet in a position to publish their report.

- Why are there no projected costs for an interconnection with Manitoba Hydro (slide 12)?

  We understand that negotiations for a power purchase agreement with Manitoba are no longer taking place at this time. Therefore, we do not expect any announcement to prompt us to make an investment.

- The Capital Expenditure numbers reported in slide 16 are not consistent with the numbers reported in slide 9 of Greg Van Dusen's presentation on revenue requirement. Mike's slide 16 reports Common (1999-2005) as $54M while slide 9 of Greg's presentation reports a Shared Services & Other totaling $85M for just 2003-2005. Also, slide 16 of Mike's presentation reports Operating as $53M for 2006-2008, while Greg's slide 9 reports Operation as $52M for the same time period.

  Mike Penstone noted that Hydro One would review these numbers and report back to stakeholders. An email was sent to all stakeholders on July 28, 2006 informing stakeholders that Mike Penstone's presentation with revised numbers has been posted on the project website.

- There seems to be a discrepancy between slides 3 and 16. Capital expenditures are shown as totaling $1.9 billion for the period 1999-2005 on slide 3 versus $2.2 billion on slide 16.

  These are different types of expenditures. Slide 3 is in-service additions and slide 16 is capital expenditures.

2.3 Primary Drivers for Transmission OM&A

Mike Penstone (Director, System Investment) presented an overview of the primary drivers for Transmission OM&A. Hydro One has an aging asset base. As assets age, performance deteriorates so there is increased need for maintenance. If Hydro One does not adequately maintain its assets, supply security and reliability to customers is at risk, which may mean increased interruptions and failures. Asset failures can also decrease system transfer capacity, which increases the cost of energy. Mike discussed how transmission OM&A is forecast, and how operations and maintenance requirements are determined. He outlined transformer maintenance and described asset demographics (i.e., increasing asset age over time). Equipment failure rates are increasing (e.g., for various types of

critical system assets such as transformers and circuit breakers). Five hundred kV transformers are the newest but the worst performers; the failure rate is one every 18 months despite the fact that they are only halfway through their expected lifetime. Infrastructure is aging, requiring increased maintenance and monitoring. This is the primary driver behind the OM&A forecast.

The following questions were asked/points were clarified in ensuing discussion:

- What has happened to Hydro One's ability to get planned outages over the last few years and what is the impact on forced outages?

  Given the current situation in the province (i.e. a highly loaded transmission system) and the potential reliability impact of having critical equipment out of service, the number of outage windows that IESO permits Hydro One for planned maintenance is shrinking. This is a contributing factor to declining performance of some equipment.

- Who audited the Barrie Operations Centre and do they also audit failure rates of major components?

  The Barrie audit was sponsored by the North American Electrical Reliability Council (NERC) based in Princeton. The audit team was comprised of individuals from utilities across North America. All transmission operators across North America are audited on a regular basis. NERC can ask for information on failure rates but there currently are no specific standards (i.e., on what constitutes an acceptable failure rate for equipment) for many of the areas that they audit. They do not ask for failure rates but they do ask for evidence that equipment is being adequately maintained and how a utility's assets are performing. So they cannot say a utility did not meet a specified standard, but they can say that a utility is engaging in poor practices.

- Is the asset aging phenomenon showing up elsewhere in the Hydro One budget?

  Yes – in the spares requirement. This is increasingly a challenge since suppliers are completely booked (due to demand from other North American and offshore jurisdictions – Alberta, China, India). We now face a seller's market rather than the buyer's market of a few years ago. Consequently, sourcing high voltage equipment such as transformers, breakers, conductors, insulators and other materials on a timely basis is a growing concern. So not only are our failure rates increasing but implementing our capital program will face an additional challenge: replacement times are getting longer.

- Are other utilities experiencing the same failure rates for the 500 kV autotransformers?

  The industry is seeing the same trend that Hydro One is experiencing – newer transformers are failing much earlier (i.e., in 20 years) than the older units.

  These autotransformers were built specifically to Ontario Hydro specifications that were less than what they had required previously because of the size of the units and issues around the transportation of the units from the manufacturer to the stations. They had to be designed to be as small as possible.

- Why did Hydro One not invest adequately in maintenance in the past?

  Hydro One has only been the steward of the transmission system for a few years. The old Ontario Hydro had responsibility for transmission, distribution and generation, so transmission was not necessarily the primary focus. There was considerable focus on generation and sustaining the nuclear program. As a result, Hydro One inherited maintenance practices that were not what they should have been and has been changing them ever since the company was created.

- Is Hydro One using the OEB distribution ruling with respect to the treatment of common costs?

  Yes, the same methodology is being used in the transmission application.

- Slide 3 indicates that OM&A costs are forecast to increase by 35% from 2003 to 2007. Is that a one-time jump? Where does this 35% come from?

  This is for Sustainment OM&A only. The 35% is the increase we forecast over the five years between 2003 and 2007 to 2008.

- Given your comments earlier on the aging of assets, what do you expect the increase in OM&A expenditures to be for 2009 to 2010? It looks like it might increase considerably.

  It is a concern. We are trying to find better ways to monitor when assets require maintenance and when they are beginning to degrade. We are trying to implement the notion of "just-in-time" maintenance. There are step increases in maintenance costs and there is a threshold beyond which these costs become so high that it is less expensive to invest in a new asset. We maintain an asset until it is deemed to have reached the end of its life and then we replace it. With respect to asset demographics, as more assets enter the higher cost maintenance phase, OM&A costs will continue to increase in the 2009 to 2010 period.

- With respect to your Microwave Replacement Program, is the new broadband digital network a private highway just for Hydro One use and how is any excess fibre optic capacity used?

  Hydro One owns its fibre optic network. Hydro One Telecom leases excess capacity to telecom entities. See Section 3.2, Microwave Replacement Investments, for additional information.

2.4 Transmission Cost Allocation and Rates

Henry Andre (Manager, Transmission Rates) described the rate pools that will be included in the Transmission Rate Application, allocation of assets and costs, revenue requirement, rates and impacts, and Hydro One's proposals on export transmission service and the regulatory assets rate rider. Consistent with the views expressed by stakeholders at the May and June consultation sessions, Hydro One will propose four rate pools: the continuation of the existing Network, Line and Transformation Connection Pools, and the addition of a Transmission (Wholesale) Meter Pool. Consistent with stakeholder input, Hydro One will also propose the splitting of the cost of Dual Function Lines (DFL)

between the Line and Network Connection Pools. Henry noted that this approach is more consistent with cost causality and the equitable treatment of all Line Connection customers.

Henry discussed how assets are allocated into the pools. About $8B are directly assigned from functional categories to a clearly associated function pool (e.g., network assets to Network Pool). There are smaller amounts that are allocated to the various pools from other functional categories. Henry provided an overview of how the asset base in the rate pools, allocation of OM&A, allocation of depreciation, and allocation of other costs are expected to change from 2007 to 2008.

The revenue requirement to be collected through transmission rates will increase from $1238M to $1274M. Henry also described how charge determinants and rates would change for each pool from 2007 to 2008. Most customers will see a slight increase in total charge impacts for 2007, but large directs will see a slight decrease. The increase is due to the higher Transformation Connection Pool rate. Many large direct customers and some LDCs own their own transformation so they will not see the Transmission Connection pool rate increase. Hydro One's analysis assumes the *status quo* rate for the Export Transmission Service (ETS). The analysis also assumes the 2007/2008 ETS revenue is returned to customers in the year it is earned. Henry concluded by explaining how the regulatory assets rate rider will be used to disburse $24.96M to customers.

The following questions were asked/points were clarified in ensuing discussion:

- How does the splitting of the cost of DFLs (slide 3) between Line and Network Connection take place?

  The split is based on a customer's average monthly peak load as a proportion of the peak capacity served by the DFL. Only asset costs, not customers, shift between Line and Network pools.

- Is the Transformation Asset Base in slide 5 net of customer capital contributions?

  Yes.

- Are the number of meter points referred to in slide 10 strictly Hydro One's?

  It includes all meter points in the province owned by Hydro One that are still covered by the regulated meter service.

- Is the $6M number for small LDCs in slide 12 due to rounding?

  Yes.

- Slide 12 indicates that large LDCs will see a 4.1% rate increase. Hydro One Distribution is one of the province's largest LDCs and is somewhat unique in that it has so many supply points. What will the rate increase be for Hydro One Distribution?

The increase will be in the same range of 4.1%.[1]

- Are any discussions under way with respect to reciprocal export agreements (slide 13)?

  Yes, we believe the IESO is in discussions with the New York IESO.[2]

- Why is the 2007 Gross Book Value (GBV) number $10.2B in slide 4 and $10B in slide 5?

  The number in slide 4 is year-end GBV. Slide 5 depicts the average GBV for the year to be consistent with the number in the revenue requirement presentation.

- Several stakeholders suggested that Hydro One include the Export Service Study in its filing.

  Hydro was planning to have the study available upon request, but will consider including it in the Transmission application.

2.5 Proposal for Incentive Adjustments to Transmission Rates

Andy Poray (Director, Regulatory Policy and Support) presented the rationale for Hydro One's proposed plan for incentive based adjustments to establish 2009 and 2010 transmission rates. While there is successful experience with incentive regulation (IR) in the United Kingdom (U.K.) and Australia, there is less evidence of success in North America. The U.K. and Australian situations, experience and issues are similar to those in Ontario and therefore can provide some guidance. In both of these jurisdictions, performance incentives are designed to encourage efficient investment and good operating practices to improve utilities' service quality.

Hydro One is proposing IR now to ensure effective drivers are in place to manage the significant transmission investments that need to be made. As part of its application, Hydro One will submit a proposal to establish the incentive plan, with details to be developed later. The incentive plan will be designed to accommodate the capital investment forecast once the IPSP is available as well as the capital and OM&A investment for sustaining existing transmission infrastructure, inflation and productivity adjustments and full cost recovery of investments.

The following questions were asked/points were clarified in ensuing discussion:

- What do you expect the OEB to approve in this application with respect to Incentive Adjustments?

  Hydro One's objective is to have the OEB accept the proposed concept, process, methodology and

[1] *Subsequent to the meeting the expected average impact on large LDCs has been recalculated to be 3.9%. The expected impact on Hydro One Distribution is 3.3%, the difference being attributable to the mix of delivery points that pay Line Connection and Transformation Connection charges.*

[2] *Subsequent to the meeting it has been confirmed that the IESO has had some discussions with the New York IESO and the Mid-west ISO.*

model, and the suggested adjustment elements that would apply. The specific details and a capital forecast would be developed and submitted at a later time. We may also have some proposals as to what other cost drivers should be included. Our objective is to ensure we have a reliable transmission system.

- Will the primary direction in the IR proposal be price or revenue cap? If it is price cap, does that mean rates? How would this affect other transmitters who would be bound by the same price?

  Both price and revenue cap would achieve the desired outcome, but we think price cap is more consistent with what the OEB is trying to do in Distribution.

  Price cap means rate cap. As for how a price cap would affect other transmitters' rates, Hydro One's share of the total revenue requirement would not change and other transmitters would still get their approved share. Given that we have uniform rates, we would have to describe how a price cap approach would work, how it would affect other transmitters and how the pieces fit together.

- Price cap is a top-down approach, but some level of capital expenditure is still implicit. How do you marry that with a capital forecast, which is more of a bottom-up approach?

  The U.K. model uses a combination of bottom-up and top-down. They forecast the revenue requirement; then, they overlay a regulatory scheme, with respect to price, onto the revenue requirement. We are more bottom-up; some cost elements may require more detailed forecasts (i.e., capital) while others may be more formula driven. There can also be different adjustments for different components.

- What does "Cost recovery of other investments deemed necessary during period, i.e., *Section 92* projects" mean in slide 7? Also, what is *Section 92*?

  We are trying cover off all the potential costs that Hydro One could be subject to as a result of projects that could come about in the 2009 to 2010 time frame. We know there will be projects associated with the IPSP that comes out in 2007 and may not be approved until early 2008. But there may be other projects that Hydro One has to undertake post 2008. The market does not stand still; other generators and customers will appear. We need some flexibility for change, given that we are not in a stable environment.

  Section 92 *is the formal process/mechanism for obtaining approvals from the OEB for lines greater than 2 km in length. It drives any change and allows for approval and cost recovery for potential development projects that Hydro One could not have anticipated but must build as a result of government directives or generator/customer demands. Unlike the gas industry, Hydro One cannot get contracts to recover costs.*

- There were various adjustment factors in the original Distribution Handbook. Have you seen this elsewhere in your research?

Both the U.K. and Australia have various adjustment factors as part of their incentive scheme.

It was noted that Hydro One views the Incentive Adjustments initiative as a mechanism to help bring Distribution and Transmission back together so that Distribution and Transmission OEB submissions are not done at different times and cover a common time horizon. If the OEB approves the Incentive Adjustments concept in terms of its direction and structure, Hydro One will have sufficient incentive to build required facilities while providing appropriate oversight for 2009 to 2010 without a full cost of service review. Participants were asked to consider whether this made sense and to forward any additional comments/ideas to Hydro One so they could be included in the submission.

- Is Distribution going to file a similar application so the two would come forward at the same time?

  No, not at this time. There is a handbook used in distribution cost of service examinations and certain regulations are currently being reviewed as part of generic hearings for Distribution. Distribution has to follow existing OEB directives that are based on a relatively simplistic North American approach to Incentive Regulations .

- Is it fair to say that this approach basically involves having a "z-factor" for extra capital projects that were not anticipated?

  That is too simplistic. There is an underlying, bottom-up forecast of costs, as in a cost of service approach, but not with the same level of detail

- There may be an issue in getting OEB approval in 2007 to implement the Incentive Adjustments concept/methodology in 2009 without knowing specific rate impacts.

  A stakeholder noted that the OEB has allowed this approach with respect to OPG's prescribed generation assets where a framework was put forward without knowing the detailed rate impact.

  A similar approach was accepted by the OEB in Distribution where it had the framework without knowing what the rate impact would be.

2.6 Transmission Benchmarking Study Update

Carm Altomare (Manager, Performance Analysis) introduced Ken Buckstaff (P.A. Consulting Group), the consultant conducting the high-level benchmarking study that the OEB directed Hydro One to undertake. Ken noted how stakeholder commentary from Session 2 had been included, provided an update on progress to date and described the next steps. This is a high-level study to cover transmission cost and performance. The objective is to determine on a best efforts basis where Hydro One stands relative to industry peers with similar characteristics on some high level cost and performance measures. The report from this study will be filed as part of the 2007 / 2008 Transmission Rate Application.

The goal in selecting a comparison panel is to include a set of comparator companies that have similar characteristics and face similar challenges (e.g., large size with substantial investment in transmission assets, greater than 2000 km of transmission lines, regular inclement weather conditions etc.). Companies have been selected as cohorts to Hydro One on a best efforts basis. Selection criteria included size, geography/weather characteristics, business structure, and market and regulatory structure. Two suggested selection criteria, 'asset condition' and 'use of smart technologies', were considered but have been excluded because the required quantitative data are not readily available. P.A. Consulting reviewed about 50 utilities in North America and applied these criteria. Several other Canadian companies may be included in the panel because they may provide additional perspective.

The performance metrics categories have been modified based on discussion from Session 2 to include costs, efficient of use of capital, service level performance and employee safety. Graphs for each metric will be provided depicting comparison of Hydro One to companies in the panel. Individual companies will not be identified to maintain the promise of confidentiality, which is a common condition of participation in this type of study. A table will consolidate the data (over three years) from the graphs to show how Hydro One compares to the rest of the panel.

Labour rate comparisons will also be included and will consider three different benchmark job categories, as requested by the OEB. There will also be a descriptive (i.e. qualitative, not quantitative) comparison of overtime approaches.

Data are still being collected and analyzed. The report will be completed in time for the filing.

The following questions were asked/points were clarified in ensuing discussion:

- What is the definition of transmission companies being used?

  This varies by companies all over North America. We have included all electric energy utilities over 50 kV (generally this includes companies having high voltage transmission facilities operating at 69 kV and above). There may be one below 50 kV.

- I understand that in Australia they define fixed assets differently than they do here. Is this a depreciated fixed asset (slide 4)?

  We have used gross fixed asset but we have actually captured data on gross and net. We will show gross and net.

- Is there a need to take into account the growth rate that these utilities are facing, as a factor in peer selection?

  Although the data do not include growth rate, growth rate can be derived because we are gathering data over a 3-year period. It does have an impact on capital investment, and one of the things we will be doing is splitting replacement capital from new investment-for-growth capital.

- Will you consider asset age (slide 6)?

No. This is a high level study. Asset age would involve an additional major study.

- I understand you cannot get the quantitative data for asset condition, but can you do qualitative analyses (e.g., a telephone survey)?

  We have had discussions with some companies. We have a qualitative sense of what their systems look like but we do not have quantitative data that we can defend in a regulatory proceeding. However, we do plan to make some qualitative comments. Also, for smart technologies, there is a similar issue since many take several years to show a benefit. So the installation of these new technologies may have occurred, with a cost, but the benefits may not have accrued yet so there is no reasonable way to determine the benefits of smart technology. These two are areas of great interest but we will not have quantitative results for this study.

- Another Canadian company that could add value to the panel (slide 7) is New Brunswick Power. It is comparable in some characteristics (but not in size). It interconnects several utilities and has a similar urban/rural mix.

  We are looking at New Brunswick Power, but we do not have all the data at this stage and may not get all the data.

- Can you consider Manitoba Hydro as another company for the panel?

  New Brunswick Power, Manitoba Hydro and Nova Scotia Power are the three companies for which we are trying to get data. They are not listed on the selection panel (slide 7) because of size and other considerations.

- For U.S. and Canadian companies, how will you deal with significant changes in the currency exchange rate over time (slide10)?

  Our plan is to use the exchange rates that were in place at the mid-point of each of the three years. However, we are open to your suggestions for other ways of dealing with fluctuating exchange rates.

- I am concerned that the exchange rate that is used may skew all comparisons and give an inaccurate appearance of poor performance from one year to the next, when there may in reality have been an improvement. Is that possibility going to be recognized in the report?

  Yes. We will consider the factors that affect performance changes.

- *Hydro One's experience is that labour rates do not seem to change with exchange rates. Do you do a different adjustment on cost of material versus wage rate?*

  Local rates are paid for labour and world prices are paid for materials. We are not capturing direct labour costs separately for all these categories. We are capturing this information at the

total cost level. We will investigate what impact exchange rates have and will then determine if it is worth the effort to separate labour from everything else. We know the average labour rate in these major categories from our annual studies. Using these averages for Hydro One may not necessarily be fair because Hydro One may do more work in-house. We have not determined how much detail we are going to need to analyze the exchange rate impact.

- Will you include the amount of work outsourced (slide 11)?

  No. At a high level, cost gives you overall performance. The next question would be, who should do the work? We treat staffing choices as a business practice rather than an outcome. We are ultimately interested in the cost to do work, not who does it.

- How do you deal with the fact that power rates or tax levels may skew comparisons?

  We concluded that the study should be about cost and the question of rates does not relate to cost, so this is not included in the study.

- Can you provide the standard deviation as well as the mean for the tables referred to on Performance Metrics (slide 10) and Labour Comparisons (slide 11)?

  Yes, good idea. We can also provide mean and median.

- When you look at the local cohort with respect to labour costs, will you include the rest of Canada?

  Yes, some companies in Ontario and the rest of Canada will be included.

- Have you considered including data on what the bond rating level is for these various companies?

  Yes, we looked at things like bond rating, debt service coverage and some other financial metrics. They were considered but we chose not to include them because the OEB directed this study be about cost.

2.7 Transmission Reliability

Yury Tsimberg (Manager, Transmission Approvals) discussed various aspects of transmission reliability and the approaches used for maintaining existing levels of reliability. Reliability is measured at the delivery points, the number of which has increased from 2003 to 2005. A customer may have more than one delivery point. There are four reliability measures: SAIDI, SAIFI, System Unavailability and Unsupplied Energy (UE). Reliability is managed at both the delivery point level and at the local area level.

At the Delivery Point level, the reliability performance of a customer delivery point is compared to an historical baseline. If the reliability is determined to be below the baseline, Hydro One will consider what can be done to improve it. Hydro One tracks historical performance to identify delivery points

with deteriorating performance. Existing levels of reliability are maintained while targeting performance outliers for improvement. Yury described how performance outliers are identified and their occurrence from 2003 to 2005. Addressing the problems at delivery points that are performing below the baselines will generate significant reliability improvements.

The overall performance for 31 local areas is determined according to historical performance of UE. For both 2004 and 2005, Yury described which IESO reliability areas met criteria, which are borderline and which did not meet criteria. He also discussed the Northeast Power Coordinating Council (NPCC) *Document A-2: Basic Criteria of Design and Operation of Interconnected Power Systems*, noted that the North American Electric Reliability Council (NERC) is moving from a voluntary to an enforcement regime, and discussed methods of managing reliability in OM&A and Capital.

The following questions were asked/points were clarified in ensuing discussion:

- What is your definition of an interruption (slide 4)?

  Voltage goes down to zero. There is no supply.

- How long must an interruption last to be considered an interruption?

  Momentary and sustained interruptions would both be reflected in the System Average Interruption Frequency Index (SAIFI). The difference between momentary and sustained is that momentary interruptions last less than one minute. Outages related to a trip and reclosure of a circuit, which interrupts supply for 10 to 20 seconds, would be included. If it is longer than a momentary interruption it also will be reflected in the System Average Interruption Duration Index (SAIDI).

- You said that transmission redundancy is not going to show as unsupplied energy. Wouldn't this affect supply?

  Transmission redundancy reduces the amount of unsupplied energy because of the improved reliability. However, there still will be some unsupplied energy at some delivery points, which will be seen in the measure 'system minutes of unsupplied energy'.

- When a transmission outage causes bottled generation, but does not cut supply to a load side customer (i.e., so there is no unsupplied energy), how is that bottled energy captured in the reliability measures?

  This is captured in Transmission System Unavailability (bullet 4, slide 4). This shows how often the system has been unavailable resulting in possible system constraints/congestion.

- Are planned outages included in SAIFI/ SAIDI?

  Yes, they are included in both measures.

- A Hydro One delivery point reliability study is underway. Will it be ready for the filing and will it capture transmission and congestion issues? The study should include generation delivery point reliability. There should be a performance measure that would consider how reliably power from generators gets into the transmission system and how this is affected by constraints due to other issues within the system. It would be nice to have that information if available.

  Generation delivery point reliability measures are part of the evolution of the Transmission System Code (TSC). Hydro One is looking for new concepts and is working on developing performance/reliability measures with respect to generators, but this is still a work in progress.

  The study will not be completed in time for the filing, but will be available in time for TSC requirements.

  Although Hydro One is a leader in the industry with respect to looking at delivery point reliability, we will not start collecting data on reliability of generation delivery points until 2007.

- When you look at instances with local area delivery points in the red zone (i.e., where performance does not meet Criterion 2, slide 10), are there recurring causal patterns?

  Typically, if there is unsupplied energy into a local area, it is likely a problem with one or more of the main interfaces connecting the local area to the rest of the system. For example, we are seeing some outages (i.e., common mode failures), because of animals. We have been installing fences to keep animals out. Hydro one is also looking at the need for other design changes.

  The IESO divided the province into 31 areas. It has only been a couple of years since this has been done, so we have not had a chance to identify the types of common mode failures that are occurring, but failure due to animals is widespread throughout the province.

  When discussing common mode failures and trends in reliability, we try to track what caused each outage and fix the problem. We monitor on a monthly basis, and report that information on the local areas to the IESO. The problems with failures caused by raccoons occurs more on a seasonal basis around late spring.

- Do 500 kV autotransformer failures also show up as a reliability issue in the delivery point measures?

  They are part of the bulk power system and affect system availability significantly more than unsupplied energy, SAIDI or SAIFI type failures. The 500 kV autotransformer failures likely would not show up in the 31 local areas, but these are reported to the IESO separately.

2.8 Transmission Power Quality

Ajay Garg (Manager, Transmission Load Connections) discussed the factors affecting power quality, including associated parameters, manufacturer equipment standards and Hydro One initiatives to address power quality. Power quality refers to voltage fluctuations that adversely impact customers or

utility operations. Many factors can impact power quality, some of which are beyond Hydro One's control. Problems may originate on both the supply side (i.e., transformer stations) and the customer side (i.e., customer equipment), but the majority of power quality issues and related mitigation measures are within customer operations. Issues may result from discrepancies between manufacturer standards for end-user equipment and utility supply standards. Typically, mitigation measures on customers' equipment may be required to prevent power quality problems. Hydro One has put in place a number of power quality initiatives, including a power quality inquiry response process and the installation of power quality monitors. Hydro One, customers and equipment manufacturers must work together to ensure that equipment meets appropriate power quality standards.

The following questions were asked/points were clarified in ensuing discussion:

- Are there power quality issues associated with wind generators?

  There can be issues around how they are grounded (e.g., locations where grounding may not be effective) and the fact that operators may face economic constraints to make these projects feasible. Because they operate intermittently (i.e., start and stop), and use synchronous/induction generators, they can cause voltage dips.[3] *Voltage fluctuations and harmonics associated with wind generators can affect power quality in nearby areas.*

- It is not a bad idea to hold customers accountable for having equipment that can operate through expected system voltage fluctuations, harmonics, etc. But holding customers accountable can be difficult if they do not know what standards Hydro One is working with and what standards are applicable to them. Is there a Hydro One standard for sags and swells on the system?

  There is no specific Hydro One standard. Hydro One is guided by the Transmission System Code and industry standards, such as those from the Canadian Standards Association (CSA) and the International Electrotechnical Commission.

- Now that the power quality monitoring pilot has been completed, is there a plan to publish the data so we can see Hydro One's performance? This should be part of the standard reporting on Hydro One performance, along with reliability.

  We are working toward that end and we are also providing our data to the CSA process. Power quality is a very complex issue. Analyzing these complex data and drawing the right conclusions is a challenging and time-consuming task. We need more data and analysis to confirm what power quality issues affect a given customer class and how best to mitigate the problems.

- Is Hydro One planning annual reporting of the data and research results associated with the power quality monitoring program?

  The monitoring pilot was mainly to confirm the performance of the monitors. It was also used to troubleshoot problems in specific areas for certain customers. We do not have enough data or analysis to issue a system level report at this time. This is a highly complex and industry-wide

[3] *Wind generators' control systems utilize inverters/converters, which introduces harmonics on the system.*

issue. The data are very complex and we are still working on how to interpret them. For example, we are trying to draw conclusions as to whether there are variations in power quality in different parts of the province based on, for example, the number of incidents over a certain threshold. It is also important to try to match a customer complaint with data from a monitor where that is possible. That is why customer reporting of power quality incidents is so important in expediting the response process.[4]

- As long as we are moving forward, I am very sympathetic to the challenges and complexity facing Hydro One with respect to the power quality issue. Hydro One is ahead of others in this area. But power quality has been dealt with in a reactive way by both Hydro One and its customers for many years. I would like to see it move more into the managed realm, at least in those areas where it can be done, perhaps on the design, construction and operation of the system or the equipment on the customer side.

  Power quality issues have been around for many years. The technical standard-setting process by the industry is lagging because of the complexities associated with power quality parameters. We are working with the CSA to develop some fundamental standards. In the meantime, Hydro One's parallel initiatives – the Power Quality Inquiry Response Process and the Power Quality Monitoring Program – will allow us to play a key role in setting industry standards as well to as work with our customers to troubleshoot and put in place appropriate operating or capital solutions to power quality problems.

2.9 Session 2 Action Items and Responses

Joe Toneguzzo provided an update on Hydro One's response to follow-up action items that resulted from Stakeholder Session 2.

Service Quality / Reliability - provide details on Service Quality performance measures and management.

- Information on the metrics Hydro One uses, and how it manages reliability and power quality was provided in detailed presentations during Session 3.

Benchmarking

a. Consider providing asset condition, or asset condition/reliability trending.

- This is not being done at this time, as the data are not readily available.

b. Investigate a high-level metric, bundling OM&A plus CAPEX and the ability to unbundle it.

[4] *We need two cycles of at least 3-year data from the Power Quality monitor sites after all these monitors are in place and consistently applied. In future, we expect that such data will be available to customers.*

- This would provide useful information but there are challenges with the definitions used in the industry for sustainment and development, and with obtaining the data. Hydro One will provide as much information as possible in the benchmarking study.

c. Investigate adding a metric on new/smart technology use.

- These data are difficult to obtain and cannot be provided at this time. Also, it takes time to understand the effects of new technology, which are often not clear for some time after implementation. If a company is good at incorporating technology, and what is done is useful, this will be reflected in the cost.

d. Add debt coverage ratio to the financials.

- The benchmarking study will not include credit rating of various cohorts. Some analysis along these lines is included in the cost of capital study and this is also a consideration in utility rating.

Depreciation - provide forecasted impact of methodology change.

- This was provided in the Session 3 Revenue Requirement presentation.

Cost Allocation and Rate Design – confirm the number of short connections built each year.

- The number provided at session 2 was correct. There are about 10 per year.

Responses to Action Items from Session 3 are provided in the meeting Notes.

3.0 SUMMARY OF STAKEHOLDER-SELECTED ISSUE DISCUSSIONS

The following summarizes the discussion of the stakeholder selected issue topics. Issue Discussion #1 took place during the afternoon of Day 1. Issue Discussion #2 took place during the morning of Day 2. Presentation slides for the OM&A Asset Class Breakdown and Microwave Replacement Investments are posted at http://www.hydroonenetworks.com/en/regulatory/. Follow the links to the stakeholder consultation program.

3.1 Issue Discussion #1: Day 1 Afternoon

OM&A Shared Services Breakdown

Stakeholders asked for a comprehensive breakdown of the Shared Services & Other category of Operational Costs (see slide 8 of the Revenue Requirement presentation; section 2.1). Greg Van Dusen responded to this request. The main components of this category are the common costs associated with Transmission, Distribution and subsidiaries. Reported in this presentation are common costs that have been allocated to Hydro One's transmission business. The allocation from 2006 to 2008 is consistent with the Rudden Methodology approved in the Distribution rate case.

There are five main categories of common costs that were allocated:

1. Corporate Common Function Services;
2. Common Asset Management Cost (allocation is done using the time distribution that was part of the Rudden methodology, and was reviewed by Rudden.);
3. Information Technology Services Cost;
4. Business Telecom Cost (e.g., voice services that were purchased from Bell or Hydro One Telecom); and
5. Customer Care Costs – this is large in Distribution but much smaller in Transmission.

Other items include:

1. Cost of Sales – Revenue requirement decreases by the amount of revenue received from work done for others. The cost supporting these revenues appears here, and is primarily focused on supporting key generators in the Province;
2. Overheads Recovered on the Capital Program – This is based on the Rudden methodology for calculating the overhead capitalization rates that we apply. There is a pool of common costs, some serving the OM&A program and some serving the capital program. The methodology calculates the rate to take the appropriate amount of common costs and allocates them to the capital program. This results in a credit to the OM&A program, which gets assigned as overheads recovered on Capital;

3. Environmental Provision Credits – These are costs to remediate primarily PCB-related contamination. We have set up a liability that we draw down so the OM&A costs are incurred here and we remove them from the Shared Service & Other category and we charge depreciation. Therefore, this shows up as depreciation cost, not an OM&A cost;
4. Indirect Depreciation – Some of the costs associated with the fleet have depreciation built into them. To properly categorize that cost, we take it out of the OM&A and move it here;
5. Other
    a. Vacation reserve;
    b. Gregorian / Fiscal adjustments;
    c. Adjustments to inventory provisions; and
    d. Money received for insurance claims.

Main Items That Drive Change

From 2003 or 2004, there was an increase in the capital expenditure program ($287.5M to $431.8M) due to a larger credit associated with the Parkway Transformer Station. Also, information technology expenses decreased from 2003 to 2004 mainly because of the Inergy Supplier Initiative. Approximately $15M was paid to Inergi in 2003 as part of a contract to make certain specified process improvements that would provide future benefits to Hydro One.

From 2005 to 2006, there was a change in the asset management costs. Before 2006, some of the real estate charges were taken out of real estate, and were embedded in labour, material or surcharge rates that were charged directly to work programs. This was discontinued as a result of the cost allocation study. We now charge these costs more directly to Transmission or Distribution based on analysis of real estate assets. In 2005, there were also a couple of insurance recoveries (e.g., Cherrywood Transformer Station) that reduced costs. These do not occur in 2006, which leads to an increase in the Other/Other category in this year. There is some money set aside in 2006 for the cost of the regulatory filing.

In 2007 to 2008, there is a big step jump in the capital expenditure program (from $418.4M in 2006 to $668.6M and $766.3 in 2007 and 2008, respectively). The overhead capital credit increases as the capital program ramps up and represents a larger proportion of total cost. More of the common costs are associated with the capital program because it is a larger proportion of the work the company is doing.

Table 3.1 provides a comprehensive breakdown of Shared Services and Other costs from 2003 to 2008.

There were no follow-up questions or comments from stakeholders.

Table 3.1: Shared Services and Other Costs

Shared Service and Other Costs	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
Customer Care	3.0	4.7	4.4	3.4	1.6	1.6
Allocation of Common Asset Management Costs	33.2	35.6	36.3	54.7	58.2	57.3
Allocation of Common Corporate Costs	36.6	38.7	40.5	39.7	40.8	40.9
Information Management Services, including Cornerstone	53.2	37.8	31.1	39.6	37.5	37.5
Business Telecom	5.9	8.2	7.2	8.4	8.1	8.1
Cost of Sales	21.9	14.6	15.7	13.5	10.5	9.9
Overheads Recovered on CAPEX	(33.5)	(61.8)	(49.2)	(55.6)	(80.6)	(84.6)
Environmental Provision Credits	(3.7)	(5.0)	(6.5)	(4.2)	(4.3)	(4.1)
Indirect Depreciation embedded in SP rates	(3.5)	(3.9)	(3.7)	(4.8)	(4.1)	(4.2)
Other	12.7	0.1	(15.8)	7.0	4.7	(3.2)
Total Shared Services and Other Costs	**125.8**	**69.0**	**59.9**	**101.7**	**72.3**	**59.3**

OM&A Asset Class Breakdown

In response to stakeholder requests, Mike Penstone presented a more detailed explanation of the $46M increase in OM&A expenditures between 2006 and 2008 and the asset classes that drive the change. These include Power Equipment, Operating, Station Ancillary Systems, Site Facilities, Overhead Lines, Protection & Control, Engineering/Environmental Support and Transmission Rights of Way.[5]

There were no further questions or comments from stakeholders.

Capital Structure and Return on Equity

Allan Cowan (Director, Applications) responded to a stakeholder request for more information on the capital structure and Return on Equity (ROE). The 2007 / 2008 Transmission Rate Application is based on Hydro One's transmission business as a stand-alone entity, with its own financial requirements and risk profile. Hydro One is filing evidence from Kathy McShane (Fosters Associates) who will be a witness at the filing, if required, to defend the recommendations with respect to the 40% equity requirement and the 10.5% ROE.

Forty percent equity is a reasonable level for Networks' transmission capital structure in order to maintain an A-rating and to have access to the debt markets at reasonable costs at a time when significant capital expenditures are taking place in the industry. The current rating is for the parent company (Hydro One Networks Inc.), which has an equity component higher than the transmission regulated entity (i.e., 52% debt, 45% equity, 3% preferred equity).

Hydro One now operates in a global financial market. A 40% equity ratio is consistent with Hydro One's peers, who are international and not just Canadian-based. The market is far more competitive than it used to be. The foreign content limits for investors have been eliminated. Therefore, Hydro One must now compete globally for funds. For example, a U.K.-based utility is trying to raise capital in Canada. What would an investor prefer – a utility with 36% equity and a 9% rate of return or a utility with 40% to 45% equity and a 10% to 12% rate of return?

When assigning credit ratings, debt agencies consider items such as capital structure, ROE and depreciation that impact cash flows and coverage ratios. Hydro One feels that the 10.5% ROE is fair and reasonable for a transmission utility based on a number of tests, including: the capital asset pricing model (CAPM), other risk premium tests such as the discounted cash flow (DCF) test and the comparable earnings test. It is also consistent with utilities in the U.S. and a recent decision in Canada in which an east coast utility was awarded a 10.25% return on a 45% equity-based capital structure. If a company does not have an A-level credit rating, it would have less access to the debt market, which means higher costs. Higher costs mean higher rates for customers.

[5] *Preliminary numbers indicating quantum of change by asset class were presented at the session. Please see Hydro One pre-filed evidence for details.*

Risks are also considered, such as capital recovery for large projects, bypass risks (i.e., risk of loss of load), vast geographic coverage, age of infrastructure, complexity, regulatory/political risks and recovery issues that may arise from movement to a performance-based regulatory (PBR) framework.

The following questions were asked/points were clarified in ensuing discussion:

- The Ontario government is the shareholder but provides no guarantees?

  Yes, this is correct.

- Is Kathy McShane's work complete now? Is updating needed?

  Most of the research is complete but there will be some updating (e.g., to consider a recent Dominion Bond Rating Service (DBRS) issue that has been released).

- When will her report be circulated?

  The report will be provided in the filing in mid-September.

- It would be helpful to have it sooner if possible.

  We will ask Kathy whether she is willing to share the draft report or a high level summary of the study prior to the filing. If so, the document will be posted to the Hydro One website and stakeholders will receive email notification to that effect.[6]

- Rating agencies may give an A-rating but they can also tag potentially negative provisos onto the rating. Is there anything like that on Hydro One's credit rating?

  That depends on the rating agency. Each rating agency has a different structure. Some agencies may provide comments such as A+ stable, A+ negative, or Watch. Right now, we have a DBRS credit rating of A high with a stable rating.

- What equity risk premium is built into the 2007-2008 common equity rate of 10.5%?

  This information will be in Kathy McShane's final report.

- Are you contemplating real world or just theoretical evidence?

  Kathy looks at real world examples and analyzes real data when she develops recommendations.

- How does the underwriting cost get dealt with?

  The underwriting costs are reflected as flotation costs. The OEB historically has allowed a certain

[6] *Hydro One will post the finalized report on its web site before the full filing of the evidence in support of its application.*

percentage for that. The current OEB staff proposal for the distribution side of the business recommended a continuation of a floatation cost to cover underwriting costs.

- Did you say that Kathy's report looks at potential bypass risk?

  She has identified that there is potential bypass risk in our service territory in the longer term, but not in the test years.

- When was the last time you did a debt issue and did it clear?

  We did a debt issue in March and April of this year and they both cleared.

- Which east coast utility was awarded a 10.25% return?

  Maritime Electric.

3.2 Issue Discussion #2: Day 2 Morning

Microwave Replacement Investments

Frank Jakob gave a brief presentation elaborating on an earlier response to a stakeholder who asked about Hydro One's Microwave Replacement Program and how any excess capacity is used. The aging analogue microwave system has been replaced with a combination of fibre and digital microwave. Excess fibre strands in some cables have been leveraged to provide revenue to Hydro One Networks Inc. through short- and long-term commercial contract leases negotiated by Hydro One Telecom with other telecom entities.

The following questions were asked/points were clarified in ensuing discussion:

- Your map indicates that the new system covers only southern Ontario up to Sudbury. Your system is bigger than this. Physically speaking, how do you handle Thunder Bay and Sault Saint Marie and the rest of the province?

  Power line carriers (a telecommunication system which employs the conductors of the transmission system to send signals) are used in areas not covered by the microwave system.

- This Microwave Replacement Program is a $184M expenditure. Was there an additional expenditure for the parts of the province not covered by this program?

  The power line carrier system is starting to show end-of-life signs. We look at lead indicators, such as reliability, to assess the situation on a case-by-case basis and then make a replacement decision. These replacements have been minor in the past, but are expected to increase in the near future.

- In addition to the capital expenditure associated with the Microwave Replacement Program, is there a summary of annual financial flows (i.e., lease payments, other revenues, etc.)?

  There are service-level agreements between Hydro One Networks Inc. and Hydro One Telecom. These were filed as part of the Distribution submission. There are also other expenses, such as business telecom, that are handled through cost allocation (i.e., voice and data services provided by Bell or Hydro One Telecom to service all of Hydro One Networks Inc.).

- Does the IESO use Hydro One's telecommunications system?

  If they require telecommunication paths they would contract with Hydro One Telecom for any excess capacity.

4.0 CONCLUSION

The following next steps were discussed at the conclusion of the session:

- The report on this stakeholder consultation will be posted on the Hydro One Transmission Rate Application website when it is available;
- Hydro One requested that any additional comments be forwarded by email to Enza Cancilla (Manager, Public Affairs) at enza.cancilla@HydroOne.com; and
- No more stakeholder sessions are planned for the Hydro One 2007/2008 Transmission Rate Application.

Joe Toneguzzo thanked stakeholders for their input in to the 2007 / 2008 Transmission Rate Application. He acknowledged that there has been substantive input to all parts of the filing and that a number of changes have been made as a result of stakeholder participation. For example, stakeholders have provided invaluable guidance to the Benchmarking and the Cost Allocation & Rate Design sections of Hydro One's Transmission filing.

Susan Frank added her thanks and noted that Hydro One has found these stakeholder sessions to be extremely constructive and that they will lead to an improved Hydro One submission. She hoped that the sessions have been mutually beneficial. She expressed Hydro One's appreciation for the time stakeholders have taken to be involved in this consultation process.

ATTACHMENT #1

Stakeholder Consultation

2007/2008 Transmission Rate Application

Stakeholder Meeting#3

Metropolitan Hotel, Toronto Room
108 Chestnut Street
Toronto, Ontario

July 5 & 6, 2006

July 5 - Registration and Continental Breakfast starting at 8:30 a.m.

AGENDA

9:00 a.m.	Introductions and Agenda	Chris Haussmann, Facilitator Haussmann Consulting Inc.
9:10 a.m.	Opening Comments	Joe Toneguzzo, Director Transmission Rate Filing
9:15 a.m.	Revenue Requirement	Greg Van Dusen, Director, Corporate Accounting, Policies & Systems
10:15 a.m.	**BREAK**	
10:30 a.m.	Rate Base and OM&A	Mike Penstone, Director, System Investment
11:45 a.m.	Stakeholders to Select Afternoon Issue Discussion	Facilitator
12:00 p.m.	**LUNCH**	
1:00 p.m.	Cost Allocation and Rates	Henry Andre - Manager, Transmission Rates
2:45 p.m.	**BREAK**	
3:00 p.m.	Issue Discussion #1	Participants
4:00 p.m.	Adjourn	Facilitator

July 6 - Continental Breakfast starting at 8:30 a.m.

9:00 a.m.	Agenda for the day	Facilitator
9:05 a.m.	Transmission Benchmarking Study Update	Carm Altomare, Manager, Performance Analysis; and Ken Buckstaff, P.A. Consulting Group
10:00 a.m.	Transmission Reliability	Yury Tsimberg, Manager Transmission Approvals
10:45 a.m.	**BREAK**	
11:00 a.m.	Transmission Power Quality	Ajay Garg, Manager Transmission Load Connections
11:45 a.m.	Incentive Regulation	Andy Poray, Director, Regulatory Policy and Support
12:15 p.m.	Stakeholders to Select Afternoon Issue Discussion	Facilitator
12:30 p.m.	**LUNCH**	
1:30 p.m.	Issue Discussion #2	Facilitator(s)
3:00 pm	**BREAK**	
3:15 p.m.	Summary of Action Items – Session #2	Joe Toneguzzo
3:45 p.m.	Next Steps	Facilitator
4:00 p.m.	Thank you	Hydro One Networks

ATTACHMENT #2

Stakeholder Consultation 2007 Transmission Rate Application Metropolitan Hotel – July 5 & 6, 2006 PARTICIPANT LIST		
Organization	**Name**	
	July 5	**July 6**
Association of Major Power Consumers of Ontario (AMPCO)		Wayne Clark
Association of Power Producers of Ontario	Jake Brooks	√
Canadian Manufacturers & Exporters Association	Malcolm Rowan	√
Electrical Contractors Association of Ontario	Heather Landymore	√
Energy Probe	Tom Adams	√
Federation of Ontario Cottage Association (FOCA)	John McGee	
Federation of Northern Ontario Municipalities	Peter Scully	√
		Richard Adams
Five Nations Energy Inc.	Larry Brooksbank	√
Great Lakes Power Limited	Bob Coghlan	√
Independent Electricity System Operator (IESO)	Helen Lainis	
Ogilvy Renault (for Great Lakes Power Limited)	Jennifer Tuer	
Ontario Energy Board	Martin Davies	√
	Nabih Mikhail	√
Ontario Power Generation Inc. (OPG)	Tony Petrella	√
Power Workers Union	Judy Kwik Bayu Kidane	√
PowerStream Inc.	Ted Wojcinski	√
School Energy Coalition (SEC)	John DeVellis	√
Union Gas Limited	Partick McMahon	√
Vulnerable Energy Consumers Coalition	Michael Buonaguro Bill Harper	√
Hydro One Networks Inc.		
Assistant General Counsel, Regulatory	Mary Anne Aldred	√
Manager, Performance Analysis		Carm Altomare
Manager, Transmission Rates	Henry Andre	√
Manager, Public Affairs		Enza Cancilla
Director, Applications	Allan Cowan	
Director, Business Integration	George Carleton	√
Manager, Networks Finance	Nina Cuyegkeng	√
Regulatory Affairs	Bohdan Dumka	√
Vice President & Chief Regulatory Officer	Susan Frank	√
Manager, Transmission Load Connection	Ajay Garg	√
Manager, Planning & Reporting	Ian Innis	√
Manager, Stations & Telecom	Frank Jakob	√
Senior Regulatory Advisor	Paul Malozewski	√

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ATTACHMENT #2

Stakeholder Consultation 2007 Transmission Rate Application Metropolitan Hotel – July 5 & 6, 2006 PARTICIPANT LIST		
Organization	**Name**	
	July 5	**July 6**
Manager, Customer Support	Jim Patterson	√
Director, Transmission Investments	Mike Penstone	
Director, Pricing & Load Forecast Management	Andy Poray	
Regulatory Finance	Joanne Richardson	√
Senior Regulatory Advisor	Carolyn Russell	√
Director Transmission Rate Filing	Joe Toneguzzo	√
Manager, Asset Strategies and Standards		Yury Tsimberg
Director, Corporate Accounting, Policies & Systems	Greg Van Dusen	√
Rogers Partners LLP	Anita Varjacic	√
P.A. Consulting		Ken Buckstaff
Haussmann Consulting Inc.		
Lead Facilitator	Chris Haussmann	√
Facilitator	Tracey Ehl	√
Rapporteur	Glynn Gomes	√
Rapporteur	Peter Mueller	√