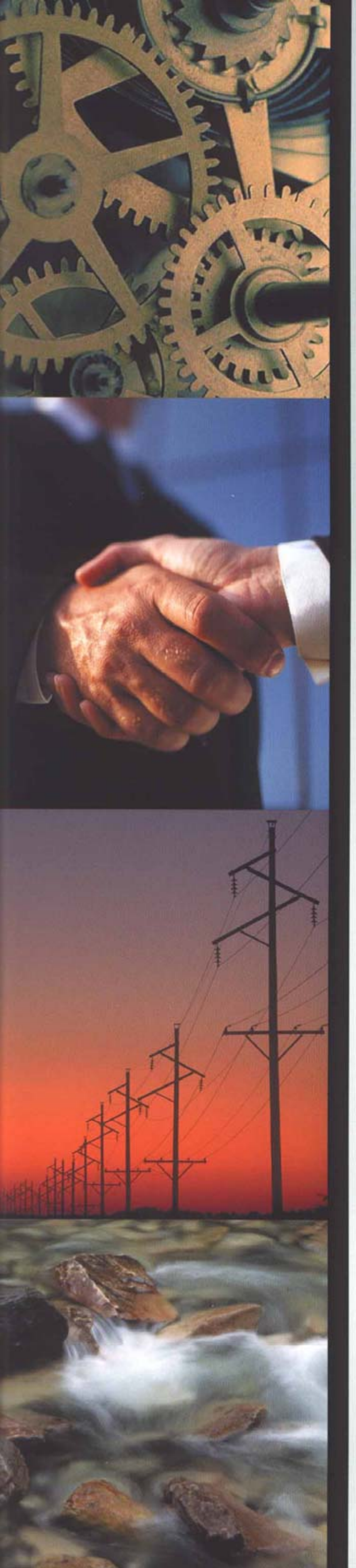

Ontario Energy Board

EES Consulting

Regulatory Cost Allocation Survey and Recommendations

January 2006

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Executive Summary

Introduction

Ontario Energy Board (OEB) requested the assistance of EES Consulting (EESC) to develop a survey on the regulatory cost allocation practices of other countries throughout the world. As part of this project, EESC used published sources to survey regulatory agencies in Canada, USA, Australia and Europe to determine the methodologies used to allocate the regulatory agency costs across the various regulated utilities. EESC also compared the survey results with the current OEB cost allocation methodology and recommended a best practice for future cost allocations.

Survey of Other Jurisdictions

EESC conducted a survey of regulatory bodies to determine the methodology used by each to allocate expenses across regulated utilities, with particular emphasis on electric and gas utilities. The survey includes regulatory agencies from five countries, as listed below.

- United States
  - Federal Energy Regulatory Commission (FERC)
  - Regulatory Commission of Alaska (RCA)
  - New York Public Service Commission (NYPSC)
  - Pennsylvania Public Utility Commission (PPUC)
- United Kingdom
  - Office of Gas and Electricity Markets (Ofgem)
- Australia
  - Essential Services Commission (ESC)
  - Australian Competition and Consumer Commission (ACCC)
- New Zealand
  - Electricity Commission
- Canada
  - Alberta Energy and Utilities Board (EUB)
  - British Columbia Utilities Commission (BCUC)
  - National Energy Board (NEB)

Based on the survey results, the best practices related to regulatory cost allocation to regulated entities and individual utilities can be summarized in the following manner:

- Use of time sheet and project accounting to track direct costs
- Cost allocation to regulated classes based on direct assignment
- Allocation to utilities based on either revenues or volume
- Cost recovery is generally based on the budgeted costs for the current year
- Allocation metrics, such as volume (sales), revenue, number of customers is generally based on actual information from the previous year

Comparison to current OEB Methodology

OEB is currently using the most common methods to allocate costs among the regulated classes and to further allocate costs to the individual utilities within each class. Table ES-1 summarizes the survey findings. OEB uses time tracking to allocate costs to the various classes, a similar method used by 60 percent of those agencies surveyed. OEB uses revenue to allocate costs within each class to the individual utilities. Forty percent of the agencies surveyed used revenue to allocate costs.

Table ES-1
Comparison of Methodology Used by OEB*

Allocation to Classes	Time (Cost) Tracking	Revenue	Volume	Customers	Comments
OEB	X				
Surveyed Agencies*	60%	20%	20%	10%	One agency used time tracking for direct costs and revenue for indirect costs
Allocation to Utilities	**Revenue**	**Volume**	**Companies**	**Customers**	**Comments**
OEB	X				
Surveyed Agencies*	40%	40%	10%	20%	One agency used combination of revenue and volume, another used revenue and customers

*Row does not add to 100%, as some utilities use a combination of methodologies.

Cost recovery for the surveyed agencies is generally based on the budgeted costs for the current year. OEB also allocates the costs of a current year budget. Those agencies using time tracking to allocate the budgeted costs generally use labour hours or direct assigned costs from the previous fiscal year. OEB's cost assessment model incorporates two years of historic data to allocate costs.

Allocation metrics, such as volume, revenue, and number of customers are generally based on information from the previous year. All agencies using revenue to allocate costs to each utility do so with the revenue generated in the previous year. OEB's cost assessment model uses the revenue collected in the previous year.

The OEB does not generally reconcile actual costs collected following the completion of the current year. Since the OEB is 100% financed by industry assessment, any excess of budget over actual cost charged is used to build a reserve for unexpected expense and as a cash float. Once the 15% reserve maximum (of the then budgeted expense and expenditure) is reached, a reconciliation of actual to budgeted costs would be completed and the excess used to reduce the assessment for the following year. Only 3 of the 10 agencies surveyed incorporate a method to reconcile costs.

Summary of Recommendations

Based on the review of best practices in other jurisdictions, understanding of OEB's cost allocation requirements of utilities and the current methodology used for regulatory cost allocation, EES Consulting recommends that the OEB use the following methodologies in allocating regulatory costs to its regulated entities:

- Direct Assignment of direct and indirect costs to regulated entities (electric distribution, electric transmitter and gas utilities). This methodology is consistent with the OEB's guiding principles, cost causation and best practices of other jurisdictions. This recommendation requires no change in the current methodology.

- Allocation of regulatory costs to individual electric distributors based on distribution revenues. This recommendation requires no change in the current methodology.

- Allocation of regulatory costs to individual electric transmitters based on transmission revenues. This recommendation requires no change in the current methodology.

- Allocation of regulatory costs to individual gas utilities based on net revenues. This recommendation requires no change in the current methodology and is appropriate given the gas commodity sourcing differences across Ontario's gas LDCs.

- Using 24 months of historical data to allocate regulatory expense is appropriate to reduce significant fluctuations in the regulatory cost to utilities. Other jurisdiction use between 12 months and 4 years of historical data.

In summary, this survey of other regulatory jurisdictions indicates that no major changes are needed in the OEB's current regulatory cost allocation procedures. The current OEB allocation methods are in keeping with industry best practices and generally accepted utility regulation.

Introduction

Overview

Ontario Energy Board (OEB) requested the assistance of EES Consulting (EESC) to develop a survey on the regulatory cost allocation practices of other countries throughout the world. As part of this project, EESC uses published sources to survey regulatory agencies in Canada, USA, Australia and Europe to determine the methodologies used to allocate the regulatory agency costs across the various regulated utilities. EESC also compares the survey results with the current OEB cost allocation methodology and recommends a best practice for future cost allocations.

Some regulatory entities receive funds from both regulated utilities and government sources. This survey addresses the cost allocation of funds to be received from OEB's regulated utilities, in particular electric local distribution companies (LDCs), electric transmitters and gas utilities. The survey deals purely with the methodology used to allocate regulatory costs across these regulated entities.

There are two cost allocation steps that need to be addressed. The first step is allocating regulatory costs across major classes (i.e. electric LDCs, electric transmission, and gas utilities). The second step that needs to be explored is the allocation of regulation costs within each major class.

Principles Behind Cost Allocation

Cost allocation can take many forms, but ultimately the cost allocated to regulated entities should reflect the cost of serving the entity. Economic theory dictates that the price of a service must roughly equal its cost, if equity among customers is to be maintained. The implication of this statement on cost allocation is significant.

The general guiding principles that must be followed when developing a Regulatory Cost Allocation method are the following:

- The cost allocation methodology should be fair and equitable and avoid undue discrimination.
- The cost allocation methodology should follow cost causation.
- The cost allocation methodology should result in costs that are fairly stable and predictable over time.
- The cost allocation methodology should be simple and easy to understand for the regulated entities.

OEB's 2005 Cost Allocation Model Review resulted in the following guiding principles for cost allocation:

1. Ultimately, customers pay all regulatory costs. The cost assessment model should be: clear and direct, fair, transparent, cost effective and provide incentive to use regulatory services efficiently.
2. The cost assessment model should ensure that costs incurred in regulating the customer groups are ultimately recovered from those customer groups.
3. The cost assessment model should allow the OEB to be financially self-sufficient and avoid the need to borrow funds.
4. All licensed market participants should contribute to the OEB's funding.
5. The cost assessment model should strive for stable and predictable assessments and/or fees for market participants.
6. The OEB should seek to mitigate year-over-year volatility in the apportionment of its funding requirements to each class of market participant.
7. Allocation within a given class of market participants should balance fairness, accuracy and predictability where possible.

It is also preferable if the cost allocation methodology results in costs that are fairly stable and predictable over time. If the methodology results in extreme swings in the regulatory costs allocated to entities, these swings can cause significant rate uncertainty to the utility customers.

General Cost Allocation Methods

Several general methodologies are used by regulatory agencies to allocate costs to regulated entities. Often the methodology used depends on whether costs are direct or indirect. Direct costs are those which are clearly and easily attributable to a specific utility or group of utilities. For example, the labour expense related to a specific utility's rate filing. Indirect costs are those which are not easily identifiable with a specific utility or group of utilities, but which are, nonetheless, necessary to the regulatory process. These costs are shared among utilities and, in some cases, among functions. Indirect, or shared, costs may include rent, telephone, postage, printing and other expenses which benefit all functions of the regulator.

The most common methodologies to allocate regulatory costs include allocating costs based on one or more of the following methods:

- Revenue
- Units of Sales (volume)
- Number of Customers
- Gross Income
- Time Tracking
- Directly Assigned by Docket Number
- Level of Effort Study

The first four allocation factors allocate regulatory costs based on the size of the regulated entities, rather than based on cost causation. The remaining three allocation factors use information related to actual services or benefits provided to allocate regulatory costs. Often regulatory agencies will use a combination of these methods, for example allocating direct costs by time tracking and then allocating indirect costs by revenues or number of customers.

When establishing a cost allocation methodology, it is important to keep in mind the impact on the regulated entities and their customers. Allocating costs based on revenues or income assumes that customers receive regulatory benefits in proportion to the cost of the services they are provided. Allocating costs based on the number of customers or units of sales assumes that the regulatory benefits are equal for all customers or for all billing units. Using these methodologies result in generic assumptions regarding the regulatory benefits received.

Allocating costs based on time tracking, direct assignment or level of effort may result in varying regulatory costs across regulatory entities, depending on work performed by the regulating agency. However, the customers only pay for services received.

Survey of Regulatory Cost Allocation Methods

EESC conducted a survey of regulatory bodies to determine the methodology used by each to allocate expenses across regulated utilities, with particular emphasis on electric and gas utilities. The survey includes regulatory agencies from five countries, as listed below.

- United States
  - Federal Energy Regulatory Commission (FERC)
  - Regulatory Commission of Alaska (RCA)
  - New York Public Service Commission (NYPSC)
  - Pennsylvania Public Utility Commission (PPUC)
- United Kingdom
  - Office of Gas and Electricity Markets (Ofgem)
- Australia
  - Essential Services Commission (ESC)
  - Australian Competition and Consumer Commission (ACCC)
- New Zealand
  - Electricity Commission
- Canada
  - Alberta Energy and Utilities Board (EUB)
  - British Columbia Utilities Commission (BCUC)
  - National Energy Board (NEB)

United States

Federal Energy Regulatory Commission (FERC)[1]

FERC regulatory jurisdiction for electricity within the U.S. is over interstate commerce, such as interstate electric transmission. Therefore, all power that enters the interconnected electric grid is subject to FERC guidelines.

[1] Financial Statements, *FY 2004 Performance and Accountability Report*, Federal Energy Regulatory Commission.

Nearly all of FERC's costs are recovered through its annual charges to the industry. FERC generally does not bill directly for an electricity filing. All budgeted costs for FERC's electricity program, including hearing costs and indirect personnel costs are recovered from transmission service providers. Therefore, there is no need to allocate cost to different classes.

The annual charges will apply to an ISO, RTO or public utility if it is the entity administering the transmission tariff. Annual charges are only applicable to foreign commerce if volumes originate or go beyond the first substation in the United States. The annual charges are based on the volume of electricity transmitted in the previous year, charged in dollars per megawatt-hour ($/MWh). Each utility must submit its total volume (MWh) of electricity transmitted in interstate (and international) commerce to FERC by April 30 of each year.

Regulatory Commission of Alaska (RCA)[2]

The Regulatory Commission of Alaska regulates most companies providing telephone, electric, gas, cable, water, sewer, garbage, or steam services. RCA also regulates gas pipeline carriers.

Costs are allocated to each utility group based on the associated direct labor using time tracking. Collected costs cannot exceed a maximum of 0.70 percent of the total revenue across all utilities. In addition to the costs recovered by RCA, the recovery cost charge includes costs attributed to the Department of Law's Regulatory Affairs and Public Advocacy (DOL-RAPA) section. These costs are split on a basis of time tracking, using the DOL-RAPA labor ratios.

Costs are further allocated to each utility within the classes. All costs in the electric class are collected from each utility on a per kilowatt-hour basis. For all other classes, the costs are recovered as a percent of the adjusted gross regulated revenue for the utility to the total adjusted gross regulated revenue within the class.

Labor ratios are calculated using data from the previous fiscal year. Revenues and the electric volume are from the most recently completed set of annual regulatory filings.

New York Public Service Commission (NYPSC)

The NYPSC regulates the state of New York's electric, gas, steam, telecommunications and water utilities and oversees the cable industry. NYPSC is responsible for setting rates, ensuring adequacy of service, siting major gas and electric transmission facilities, and ensuring the safety of natural gas and liquid petroleum pipelines.

[2] *Order Establishing Regulatory Cost Charge Rates for Fiscal Year 2006, Allocating Costs, and Closing Dockets* (U-05-47 / P-05-5 Order No. 2), The Regulatory Commission of Alaska, June 29, 2005.

Nearly all of NYPSC's funding (98 percent in 2002[3]) comes from the public utilities that it regulates. In addition, NYPSC receives some funding in the form of government grants and other minor fees. All costs are recovered from the regulated classes as a whole; there is no differentiation between classes. Costs are allocated based on each utility's gross intra-state operating revenues minus $25,000. The allocated rate is applied to the utilities assessed revenue, up to a maximum of 0.33 percent.

Rates are calculated using NYPSC's budgeted costs and the revenue in a utility's most recent annual report. Once a year NYPSC performs a final assessment for the previous fiscal year based on actual costs and the most recent information on the utilities' operating revenues.

Pennsylvania Public Utility Commission (PPUC)[4]

The PPUC regulates public utilities providing electricity, natural gas, telephone service, water, wastewater collection and disposal, steam heat, transportation of passengers and property by motor coach, truck and taxicab service, pipeline transmission of natural gas and oil, and public highway railroad crossings.

The PPUC receives a majority of funding from the utilities that it regulates. In 2002, the PPUC received 93 percent of funding from fees and charges, 0.64 percent from specific charges/filings, 2.26 percent from Federal programs, and 4.1 percent from other sources. Budgeted costs are recovered from the regulated utilities based on the tracking of direct costs per class (e.g., electricity, natural gas). The direct costs are further allocated within each class based on each utility's gross intrastate revenue as a portion of the total gross intrastate revenue of the class. Indirect costs are allocated across all utilities in all classes based on each utility's portion of gross interstate revenue across all classes. The total allocated cost to each utility cannot exceed 0.3 percent of a utility's gross intrastate revenue of the previous calendar year.

Direct cost allocation uses PPUC time sheets from the previous fiscal year and the gross revenue for intrastate business for each utility from the previous calendar year. Any discrepancies between the amount collected and the actual costs of the PPUC are carried over into the budget for the next fiscal year.

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[3] *State Regulatory Commission Budget Reduction and Cost Containment: Results of a Survey*, The National Regulatory Research Institute, February 2003.

[4] The Public Utility Code, Title 66 (Subpart B: Commission Powers, Duties, Practices and Procedures), Section 510, *Assessment for Regulatory Expenses upon Public Utilities*.

United Kingdom

Office of Gas and Electricity Markets (Ofgem)[5]

Ofgem is the regulator for Britain's gas and electric industries. It is responsible for the effectiveness of markets, regulating utilities, security of energy supplies, and social and environmental implications. Ofgem is governed by the Gas and Electricity Markets Authority, which sets the policy priorities that are implemented by Ofgem.

Ofgem recovers most of its costs through license fees charged to industry. The remainder is from property rentals and other receipts. License fees apply to regulated network utilities in four classes; electricity transmission, electricity distribution, gas transmission and gas distribution. License fees are based on the number of customers in each class. In the case of the electric transmission class, it is assumed to have the same number of customers as reported by the electric distribution class. Costs are further allocated to each utility within a class by the total number of customers in the utility in proportion to the total number of customers in the class. A minimum annual license fee is set at £500.

Ofgem sets the license fees based on a five-year average of its budgeted costs. Each utility is required to submit the number of customers on September 30th of the previous year no later than May 1st. Discrepancies between the license fees collected and actual costs will be reconciled in the sixth year, as long as the yearly discrepancy is within a £3 million bandwidth.

Australia

Essential Services Commission, Victoria, Australia (ESC)[6]

The ESC regulates all utility services supplied by the electricity, gas, water, ports, grain handling, rail freight industries and aspects of the insurance industry in Victoria, Australia. Within the electric industry the four regulated classes include generation, transmission, distribution and retailing.

Budgeted costs are recovered from each industry class based on the tracking of costs on a project basis. Project costs are further detailed into sub-groups within each class. The total cost per sub-group is then divided by the number of participants (companies) within that class and sub-group to develop an annual license fee. Sub-groups are listed below.

- Generation
  - Less than 200 MW
  - Between 200 and 999 MW

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[5] *License Fee Cost Recovery Principles*, Office of Gas and Electricity Markets, December 19, 2005.

[6] *Essential Services Commission Annual Report 2004-2005*, Essential Services Commission.

- Greater than 1,000 MW
    - Trader
- Transmission
    - Statewide
    - Interconnector
- Distribution
    - Distribution
    - Inset Distribution
- Retail
    - Less than 1,000 customers
    - Between 1,000 and 50,000 customers
    - Greater than 50,000 customers

Australian Competition and Consumer Commission (ACCC)[7]

The ACCC regulates electricity, gas, telecommunication and airports. It is the independent national electricity regulator specializing in the regulation of transmission and wholesale markets.

The majority of ACCC's funding comes from government. The remainder is recovered from industry through miscellaneous fees. This process is under review for the 2008-2009 budget process.

New Zealand

Electricity Commission[8]

The New Zealand Electricity Commission regulates the electricity industry, including overseeing the operation of the wholesale and retail electricity market.

The Electricity Commission is fully funded by a levy on the electricity industry. Budgeted costs are recovered from all electricity industry participants, not just those regulated by the Electricity Commission. The levy is applied to each of three classes; generators, purchasers and wires companies. Purchasers are companies that buy electricity from the wholesale market and consist of retailers and direct-connect customers. Wires companies are the distribution companies and Transpower is the national transmission company. The Commission tracks costs by activity

[7] *ACCC Annual Report 2004-05*.

[8] *Electricity (Levy of Industry Participants) Regulations 2005*, March 21, 2005.

group rather than by class, and are allocated to each class by the following table. The allocation of activity costs to classes is based on industry consultation performed in 2003.

Table 1
Allocation of Costs to Classes

Activity	Generators	Purchasers	Distributors
Common Quality Operations	One-third	One-third	One-third
Market Operations	One-half	One-half	
Registry and Consumer Operations		One-half to Retailers	One-half to Distributors other than Transpower
Supply Security Operations		All	
Transmission Operations			All to Transpower
Electricity Efficiency Operations		All	
Other Activities	One-third	One-third	One-third
MACQS Reform Operations	One-third	One-third	One-third

The levy to each class is further allocated based on the quantity of electricity generated (G), purchased (P), or conveyed (D), or the estimated annual number of customer connections in a fiscal year (C), as shown in the following table.

Table 2
Application of Costs to Each Utility within Classes

Activity	Generators	Purchasers	Distributors
Common Quality Operations	G	P	D
Market Operations	G	P	
Registry and Consumer Operations		C	C
Supply Security Operations		P	
Transmission Operations			n/a
Electricity Efficiency Operations		P	
Other Activities	G	P	D
MACQS Reform Operations	G	P	D

The levy is set at the beginning of each fiscal year. The regulations contain provisions that allow the Electricity Commission to amend the levy due to significant changes in actual costs, volumes or number of customers compared to the estimates.

Canada

Alberta Energy and Utilities Board (EUB)[9]

The EUB regulates the development Alberta's energy (oil, natural gas, oil sands, coal, and electrical) resources and the pipelines and transmission lines to move the resources to market. EUB also regulates the rates and terms of service of investor-owned natural gas, electric, and water utility services, as well as the major intra-Alberta gas transmission system.

EUB is moving toward a 50/50 split between government funding and industry funding, with slightly more than half the costs currently being funded by industry. Industry funding is collected in the form of administrative levies. Administrative levies are set annually and costs are allocated to industry classes based on each operational group's workload. Industry classes include the following:

- Oil and gas
- Oil sands
- Coal
- Utilities
  - Gas retail
  - Gas distribution
  - Gas transmission
  - Electricity retail
  - Electricity distribution
- Electric transmission
- Electric generation

EUB is not able to track staff time for each class, therefore, the operational manager for each group within EUB estimates the percentage of the group workload allocated to each sector for the previous fiscal year. The percentage is applied to the net budget of each group. Administrative costs are included in the net budget for each group. These costs were allocated to the EUB groups based on the number of full-time staff.

Within each of the utility classes, 75 percent of the annual administrative fee is allocated based on the annual revenue of each utility to the total revenue in that class and the remaining 25 percent is allocated to each utility based on their average number of customers to the total customers in that class.

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[9] *Alberta Ministry of Energy 2004-2005 Annual Report*.

The electric transmission levy is assessed to the Alberta Independent System Operator only. The levy for the electric generation class is based on the total amount of electricity generated in Albert by each operator of a power plant that is exchanged through the Power Pool of Alberta. If the annual fee is less than $5,000 the operator will be exempt from the administrative levy.

British Columbia Utilities Commission (BCUC)[10]

The BCUC's primary responsibility is the regulation of British Columbia's natural gas and electricity utilities.

All of BCUC's costs are recovered from industry, primarily through an administrative levy, with the remaining funds collected through direct billing for hearings and proceedings and minor fees. Budgeted costs are recovered from all regulated utilities in both electricity and gas sectors as a whole. The administrative fee is based on the volume of energy sold by each utility in the previous calendar year. BCUC operates on a fiscal year beginning April 1.

National Energy Board (NEB)[11]

NEB is an independent federal regulatory agency responsible for regulating the construction and operation of inter-provincial and international pipelines; pipeline traffic, tolls and tariffs; construction and operation of international and designated inter-provincial power lines; export and import of natural gas, export of oil and electricity; and frontier oil and gas activities.

Costs are allocated based on the time spent for each of the following classes:

- Oil, oil pipelines, oil products, natural gas liquids and liquefied petroleum gas
- Gas pipelines and natural gas
- Power lines under the jurisdiction of the Board and the exportation of electricity

Time spent by officers and employees of the NEB on activities directly related to NEB administration and activities indirectly related to the responsibilities of NEB are allocated among the three sub-groups in the same proportion as the amount of directly assigned time.

Costs are further allocated to the utilities within each class based on volume. For the first two classes, costs are allocated to a utility based on the forecasted volume (cubic meters) for the next year to the aggregate forecasted volume for the class. For the electric class, costs are allocated to a utility based on the sum of the current year actual or forecast volume, the volume from the two previous years, and the forecasted volume for the following year to the aggregate of the volume for the same four years.

[10] *Levy Regulation* (BC Reg. 283/88), Section 125 of the Utilities Commission Act.

[11] *National Energy Board Cost Recovery Regulations*, Section 13, National Energy Board Act, Registration December 13, 1990.

Summary of Regulatory Cost Allocation Methodologies

Overall Summary of Survey

EESC conducted a survey of numerous regulatory bodies to determine the methodology used by each to allocate expenses across regulated utilities, with particular emphasis on electric and gas utilities. The survey includes regulatory agencies from five countries, as listed below.

- United States
  - Federal Energy Regulatory Commission (FERC)
  - Regulatory Commission of Alaska (RCA)
  - New York Public Service Commission (NYPSC)
  - Pennsylvania Public Utility Commission (PPUC)
- United Kingdom
  - Office of Gas and Electricity Markets (Ofgem)
- Australia
  - Essential Services Commission (ESC)
  - Australian Competition and Consumer Commission (ACCC)
- New Zealand
  - Electricity Commission
- Canada
  - Alberta Energy and Utilities Board (EUB)
  - British Columbia Utilities Commission (BCUC)
  - National Energy Board (NEB)

The Australian Competition and Consumer Commission is not included in the survey results as they are primarily funded by the government. Table 3 summarizes the resulting class allocation methods used by each regulatory agency.

Table 3 Survey Summary – Allocation of Costs Among Classes					
	Time (Cost) Tracking	**Revenue**	**Volume**	**Customers**	**Comments**
FERC (US)			X		Electric transmission company only
RCA (US)	X				
NYPSC (US)		X			No differentiation between class
PPUC (US)	Direct Costs	Indirect Costs			
Ofgem (UK)				X	
ESC (Australia)	X				
EC (New Zealand)	X				By activity then allocated to classes
EUB (Canada)	X				Estimated by staff (not able to track time)
BCUC (Canada)			X		No differentiation between class
NEB (Canada)	X				

Costs are further allocated within each class to the individual utilities. Costs can be allocated based on a percentage of revenue, on a volume basis, by the number of companies or the number of customers. Table 4 summarizes the survey results.

Table 4 Survey Summary – Allocation of Costs Among Utilities within Classes					
	Revenue	**Volume**	**Companies**	**Customers**	**Comments**
FERC (US)					
RCA (US)	Electric Class	Other Classes			
NYPSC (US)	X				
PPUC (US)	X				
Ofgem (UK)				X	
ESC (Australia)			X		
EC (New Zealand)		X			Based on Activity and Class
EUB (Canada)	75%			25%	
BCUC (Canada)		X			Per Giga-Joule
NEB (Canada)		X			Electric – 4 years Others – Forecast year

In this survey, 6 out of 10 regulatory agencies use a form of time-tracking to allocate costs to the various regulated classes (e.g., electric distribution, electric transmission, gas). The four remaining agencies use one of the other methods available, where costs are allocated based on the revenue generated in each class, the volume of energy in each class, or the total number of customers in each class.

Costs are further allocated within each class to individual utilities. In the survey, 4 of the 10 agencies assess costs based on a percentage of revenues and 4 of the 10 agencies use volume of energy to allocate costs, with one of the four regulatory agencies using both methods (volume for the non-electric classes and revenue for the electricity class). Other methods include the number of customers in each utility or dividing the costs equally among all utilities within the class.

Cost recovery is generally based on the budgeted costs for the current year. Ofgem generates costs based on a 5 year budget. Allocation metrics, such as volume, revenue, and number of customers are generally based on information from the previous year. NEB uses a four year combination of actual and forecasted electric sales, and one year of forecast sales for the other utility classes. In some cases (NYPSC, Ofgem, New Zealand EC), actual costs and metrics are reconciled following the completion of the current year.

Current OEB Cost Allocation Methodology

The OEB collects its regulatory costs through assessments to the natural gas and electricity utilities that it regulates. The approach used by the OEB to allocate costs is to first allocate across types of regulated classes and then among the individual utilities within each regulated class.

A cost assessment study was undertaken by the OEB in fall, 2004, to review alternative cost assessment models and recommend a new model that would address the impact of both recent legislative changes on the OEB and changes in the current mix of energy market participants. There were several reasons mentioned by the OEB for the review of the cost assessment model:

- OEB's mandate changed due to changes in the energy market. The OEB's role includes rate setting, licensing and monitoring compliance of market participants, responding to consumer inquiries and complaints, and providing consumer information and education. The OEB needed to address cost allocation to entities other than electric distribution, electric transmission and gas utilities.
- The cost assessment model was reassessed in the context of the current mix of market participants and with an understanding of how activities associated with each type of participant drive the OEB's costs.
- The OEB's financing situation changed such that OEB could no longer rely on the Province for appropriations from the Province's Consolidated Revenue Fund. The OEB must have to ensure that working capital and other cash requirements are met.

The cost assessment study in 2004 examined: the existing cost assessment processes within the OEB; the mix of market participants today and how their activities drive the OEB's costs; new financing options for the OEB; and regulatory best practices in other jurisdictions. The study and subsequent stakeholder inputs resulted in a new cost assessment model for the period April 1, 2005 through March 31, 2005 fiscal year.

The new model allocates regulatory costs using the following methodology:

- Regulatory direct costs are allocated to the regulated entities (electric distributors, electric transmitters and gas utilities) based on direct assignment. Direct costs are costs that reasonable can be assigned to one of the regulated entities and include:
  - Staff costs as recorded in a time tracking system
  - Call centre costs based on calls received, and
  - Specific project costs related to a specific regulated entity.

- Indirect costs, costs that can not be specifically assigned to a regulated class, are allocated in direct proportion to the class' share of direct costs. Indirect costs include:
  - Administrative labour expense
  - Lease costs, and
  - Other administrative and general costs that can not be directly assigned.

- Cost Allocation within each regulated class is done using the following methodologies:
  - Gas Distribution Class: Net Revenues (revenues from distribution, transportation, storage and other, but not from commodity sales)
  - Electric Distribution Class: Distribution Revenues
  - Electric Transmission Class: Transmission Revenues

- OEB sets annual budgets and bill regulated entities for 25 percent of the allocated cost on a quarterly basis.

The current cost assessment model uses time tracking data for the most recent 24 months, unless an adjustment for a significant distortion is implemented by the Board. In addition, budgeted direct project costs are allocated based on the last two fiscal years of actual project costs. An adjustment may also be implemented by the Board if deemed necessary to reduce distortion in the cost allocation. Due to implementation issues in 2005-06, only 1 year of actual historical data (rather than 2 years) will be used for cost allocation purposes.

Comparison to Methodology Used by OEB

OEB is currently using the most common methods to allocate costs among the regulated classes and to further allocate costs to the individual utilities within each class. Table 5 summarizes the survey findings. OEB uses time tracking to allocate costs to the various classes, a similar method used by 60 percent of those agencies surveyed. OEB uses revenue to allocate costs within each class to the individual utilities. Forty percent of the agencies surveyed used revenue to allocate costs.

Table 5
Comparison of Methodology Used by OEB*

Allocation to Classes	Time (Cost) Tracking	Revenue	Volume	Customers	Comments
OEB	X				
Surveyed Agencies*	60%	20%	20%	10%	One agency used time tracking for direct costs and revenue for indirect costs
Allocation to Utilities	**Revenue**	**Volume**	**Companies**	**Customers**	**Comments**
OEB	X				
Surveyed Agencies*	40%	40%	10%	20%	One agency used combination of revenue and volume, another used revenue and customers

*Row does not add to 100%, as some utilities use a combination of methodologies.

Cost recovery for the surveyed agencies is generally based on the budgeted costs for the current year. OEB also allocates the costs of a current year budget. Those agencies using time tracking to allocate the budgeted costs generally use labour hours or direct assigned costs from the previous fiscal year. OEB's cost assessment model incorporates two years of historic data to allocate costs.

Allocation metrics, such as volume, revenue, and number of customers are generally based on information from the previous year. All agencies using revenue to allocate costs to each utility do so with the revenue generated in the previous year. OEB's cost assessment model uses the revenue collected in the previous year.

The OEB does not generally reconcile actual costs collected following the completion of the current year. Since the OEB is 100% financed by industry assessment, any excess of budget over actual cost charged is used to build a reserve for unexpected expense and as a cash float. Once the 15% reserve maximum (of the then budgeted expense and expenditure) is reached, a reconciliation of actual to budgeted costs would be completed and the excess used to reduce the assessment for the following year. Only 3 of the 10 agencies surveyed incorporate a method to reconcile costs.

Recommendations and Conclusion

This section addresses the cost allocation options available to OEB both for allocation costs across regulated classes and within each regulated class.

Options for OEB

The cost allocation survey addressed the methodology used to allocate costs in two areas: allocation of costs among regulated classes and allocation of costs among utilities within each regulated classes. In general, the options for both areas are similar.

Regulated Class Assignment

- Direct assignment method – The direct assignment methodology would assign direct and indirect costs among LDCs, electric transmitters and gas utilities based on time tracking, coding of projects, and other means of directly assigning costs. This is the methodology currently used by OEB and generally used by most jurisdictions surveyed.

- Allocation factor method – Another methodology that can be used to allocate costs across regulated entities is the allocation factor method. In this case, a representative allocation factor (revenue, volume, number of customer) would be used to allocate costs among electric distributors, electric transmitters and gas utilities.

- Proportional method – The proportional method evenly allocates costs by the number of regulated classes. In this case there are three regulated entities, and the proportional method would allocate 1/3 of the cost to each entity.

- Mixed method – The final method available to allocate costs across regulated entities incorporates a combination of the direct assignment method and the allocation factor method. The mixed method allocates direct cost based on direct assignment and applies a representative allocation factor (revenue, volume, number of customer) to the regulatory indirect costs.

Allocation Within Regulated Class

- Revenue allocation factor method – The revenue allocation factor uses revenues, net revenues, net income, etc. to allocate regulatory costs across utilities.

- Volume allocation factor method – The volume allocation factor uses MWH, GJ, or other sales volumes to allocate regulatory costs across utilities.

- Customer allocation factor method – This method allocates regulatory costs across utilities based on the number of customers.

- Mixed method – This method would combine one or more of the above mentioned methods. For example, EUB applies this method and allocate regulatory costs across utilities based on 75% revenues and 25% number of customers.

- Direct assignment method – The direct assigned method would require tracking of regulatory costs by utility and allocate regulatory costs (direct and indirect) based on direct assignment by utility.

Best Practice from Other Jurisdictions

Based on the survey results, the best practices related to regulatory cost allocation to regulated entities and individual utilities can be summarized in the following manner:

- Use of time sheet and project accounting to track direct costs
- Cost allocation to regulated classes based on direct assignment
- Allocation to utilities based on either revenues or volume
- Cost recovery is generally based on the budgeted costs for the current year
- Allocation metrics, such as volume (sales), revenue, number of customers is generally based on actual information from the previous year

Recommended Option for OEB

Based on the survey and best practices from other jurisdictions, it is clear that the direct assignment methodology is recommended to be used for cost allocation across regulated classes. This is the current practice of OEB and it appears to be reasonable and follow standard cost allocation principles. This is a common methodology used by several other jurisdictions and it results in an allocation method based on cost causation principles.

The cost allocation method used to allocate cost across utilities within each regulated class need to be discussed separately for each class. Each regulated class consists of several different utilities that differ in size and which have different regulatory needs.

Electric Distributors

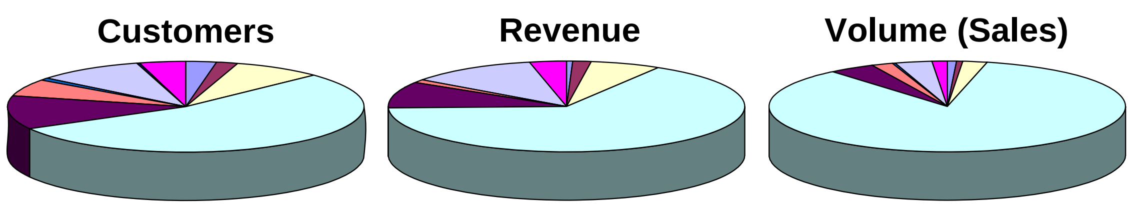
Ontario has approximately 90 electric local distribution companies (LDCs). These LDCs range from small local LDCs to large utilities such as Hydro One. The cost allocation method for this class should theoretically reflect the relative regulatory needs of each utility and be based on cost causation. However, direct assignment is very difficult at this allocation level, and allocation factors, such as those described above, are often used instead.

The review of methodologies at other jurisdiction demonstrated that the most common allocation factor used to allocate regulatory cost among utilities is either a volume (MWh) or a revenue allocation factor. The revenue allocation factor is currently used by OEB to allocate the regulatory costs among electric LDCs.

The impact of using a specific allocation factor can be seen below in Chart 1. Data was collected for a representative sample of the electric distributors in Ontario to illustrate how choosing a certain allocation factor impacts the regulatory costs allocation.

The chart below demonstrates how the methodology used to allocate regulatory costs would change the regulatory costs allocated to each utility. The utility represented by light blue would be allocated approximately 50% of the regulatory costs of the customer allocation factor method was used. On the other hand, if the volume allocation factor is chosen, the utility would be allocated more than 75% of the regulatory costs. If revenue was chosen as the allocation factor, the utility would be allocated approximately 65% of the regulatory costs.

Chart 1
LDC Cost Allocation Factors



It is important that the data used to determine the cost allocator is consistent across utilities and over time. It is therefore preferable that a cost allocator such as revenues, which is part of the utilities annual filing with the OEB, is used for cost allocation purposes. This also reduces the impacts on the utilities.

Based on the review of other jurisdictions and OEB's current methodology, it is recommended that the current policy of allocating regulatory costs to the individual LDCs based on revenues continues. The equation to be used for this allocation methodology is the following:

EDRC = (EDUR/EDR)* EDRC

Where:

EDRC = Regulatory Costs allocated to the individual electric distributor

EDUR = Annual revenues of the individual electric distributor

EDR = Annual revenues of the electric distributor class

EDRC = Regulatory Costs allocated to the electric distributor class

Electric Transmitters

Hydro One controls approximately 97% of the transmission lines in the Province and is therefore likely to be allocated the majority of regulatory costs regardless of the allocation methodology used. Currently, regulatory costs are allocated among the electric transmitters based on revenues by utility.

Another option often used to allocate costs by transmitter is by volume. This methodology is, for example, used by FERC. The review of the methodology used at other utilities suggests that using the revenue allocation factor is appropriate to allocate regulatory costs across utilities. It is therefore recommended that the current policy of allocating regulatory costs to the individual electric transmitters continue.

The equation to be used for this allocation methodology is the following:

TURC = (TUR/ETR)* ETRC

Where:

TURC = Regulatory Costs allocated to the individual Electric Transmitter utility

TUR = Annual transmission revenues of the individual Electric Transmitter utility

ETR = Annual transmission revenues of the Electric Transmitter class

ETRC = Regulatory Costs allocated to the Electric Transmitter class

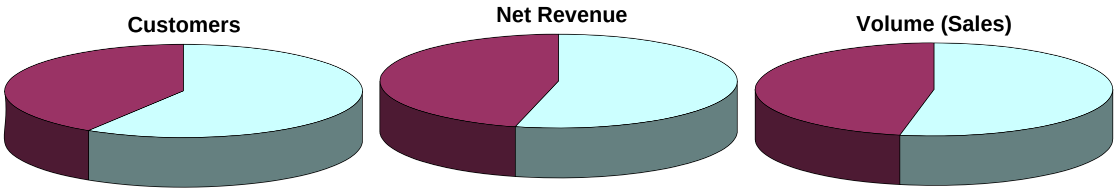
Gas Utilities

The OEB currently allocates costs among gas utilities based on net revenue. This class consists of only three utilities: Enbridge, Union and Natural Resource Gas. In the past, the OEB utilized a complicated equation based on both revenues and number of customers. However, this methodology was replaced by the current model, since there was no strong correlation shown between the number of customers and the regulatory costs associated with a particulate gas distribution utility.

Allocating costs by revenue is very common based on the results of the survey. Another cost allocation option for this class would be to allocate regulatory costs by volume. This methodology is, for example, used by RCA, EC, BCUC and NEB.

The charts below provide an example based on readily available data of the allocation of regulatory costs depending on the allocation method chosen.

Chart 2
Gas Utility Cost Allocation Factors



In this case, the volume and revenues allocation factors would result in approximately the same allocation of regulatory costs across utilities. Note that this data is sample data and should not be used for the actual allocation of regulatory costs across the gas utilities.

Based on the survey results and the review of the current OEB methodology, it is recommended that the current policy of allocating regulatory costs to the individual gas utility continue. The equation to be used for this allocation methodology is the following:

GURC = (GUR/GR)* GRC

Where:

GURC = Regulatory Costs allocated to the individual Gas Utility

GUR = Annual net revenue of the individual Gas Utility

GR = Annual net revenue of the Gas Utility class

GRC = Regulatory Costs allocated to the Gas Utility class

Summary of Recommendations

Based on the review of best practices in other jurisdictions, understanding of OEB's cost allocation requirements of utilities and the current methodology used for regulatory cost allocation, EESC recommends that the following methodologies are used to allocate regulatory costs to regulated entities:

- Direct Assignment of direct and indirect costs to regulated entities (electric distribution, electric transmitter and gas utilities). This methodology is consistent with the OEB's guiding principles, cost causation and best practices of other jurisdictions. This recommendation requires no change in the current methodology.

- Allocation of regulatory costs to individual electric distributors based on distribution revenues. This recommendation requires no change in the current methodology.

- Allocation of regulatory costs to individual electric transmitters based on transmission revenues. This recommendation requires no change in the current methodology.

- Allocation of regulatory costs to individual gas utilities based on net revenues. This recommendation requires no change in the current methodology and is appropriate given the gas commodity sourcing differences across Ontario's gas LDCs.

- Using 24 months of historical data to allocate regulatory expense is appropriate to reduce significant fluctuations in the regulatory cost to utilities. Other jurisdiction use between 12 months and 4 years of historical data.

In summary, this survey of other regulatory jurisdictions indicates that no major changes are needed in the OEB's current regulatory cost allocation procedures. The current OEB allocation methods are in keeping with industry best practices and generally accepted utility regulation.