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July 23, 2012

Randolph F. Robinson
21570 Telegraph Trail
Langley, BC
V1M 2K8

Attention: Mr. Randolf F. Robinson

Dear Mr. Robinson:

Re: FortisBC Energy Utilities (comprised of FortisBC Energy Inc. ("FEI"), FortisBC Energy Inc. Fort Nelson Service Area ("FEFN" or "Fort Nelson"), FortisBC Energy (Vancouver Island) Inc. ("FEVI"), and FortisBC Energy (Whistler) Inc. ("FEW") Common Rates, Amalgamation and Rate Design Application (the Application)

Response to Randolph F. Robinson ("RRobinson") Information Request ("IR") No. 2

In accordance with Commission Order No. G-83-12 setting out the Regulatory Timetable for the review of the Application, the FEU respectfully submit the attached response to RRobinson IR No. 2.

If there are any questions regarding the attached, please contact Paul Craig at 604-592-7459.

Yours very truly,

on behalf of the FORTISBC ENERGY UTILITIES

Original signed:

Diane Roy

Attachment

cc (e-mail only): Commission Secretary
Registered Parties

1. Please provide the most recent instructions /manual that was used to conduct the annual budget submission process for the company as a whole. In particular, it should include the instructions carried out by cost centres with a copy of the views/screens that would be accessed to enter the input by a person responsible for submitting their budget.

Response:

The detailed budget instructions were filed in the FEU's 2012-2013 RRA proceeding, which established the costs on which the rates in this Application are based. As such, the detailed budget instructions can be found in Exhibit B-65 of the FEU's 2012-2013 RRA proceeding at the following link http://www.bcuc.com/Documents/Proceedings/2011/DOC_28873_B-65_FEU-Undertaking-37-Revised.pdf.

2. Please provide examples of activity-based budgeting used in the annual budget submission.

Response:

The use of activity-based or zero-based budgeting was discussed in the FEU's 2012-2013 Revenue Requirement Application proceeding, and was summarized on pages 16 to 22 of the FEU's Final Argument in that proceeding, included here as Attachment 2. In addition, the response to BCUC IR 2.21.1 (Exhibit B-17) in the same proceeding provided detailed examples of activity-based budgeting in field services delivery, and is also included in Attachment 2.

3. Please provide a list of Key Performance Indicators (KPIs) that are used in the budget submissions.

Response:

KPIs that are tracked as part of the budget process include:

Forecasting:

- Customer Growth
- Customer Consumption

- Gas Throughput
- New Customer Capture Rate

O&M:

- O&M/Customer
- O&M Productivity
- FTE Growth
- Bad Debt Experience Rating

Employee Safety:

- Vehicle Accidents
- All Injury Frequency Ratio
- Wellness

Customer Satisfaction:

- Residential/Small Commercial
- Large Commercial/Industrial
- Builder/Developer

Operational:

- Public Contact with Pipelines
- Emergency Response Time
- Speed of Answer - Emergency
- Speed of Answer - Non Emergency
- Transmission Reportable Incidents
- Customer Bills not meeting criteria
- % of Transportation Bills Accurate
- Meter Exchange Appointment Activity
- Accuracy of Transportation Meter Measurement 1st Report
- BCUC Complaints
- Leaks per Kilometer
- # 3rd party distribution system incidents

Call Centre:

- Under development

4. Please provide the criteria used to allocate the costs in cost centres. In particular, the criteria used to allocate direct and common costs to operating expenses and asset costs.

Response:

Costs are not allocated within cost centres since employees are assigned directly to a cost centre, and their costs and associated expenses are directly charged to that cost centre. Cost centres are then grouped together to create the activity view of O&M which is used in the utilities' revenue requirements.

The criteria used to allocate shared services costs are included in the response to RRobinson IR 2.6 below.

The criteria to allocate costs to operating expenses and asset costs are included in the Asset Accounting Manual, which was filed in the FEU's 2012-2013 RRA proceeding. The Asset Accounting Manual can be found in Attachment 99.1 to the Response to BCUC IR 1.99.1 (Exhibit B-9-1) of the FEU's 2012-2013 RRA proceeding which is provided in Attachment 4 for convenience.

5. Please provide the auditor's comments on the application of the criteria used to allocate the costs. In particular, where the auditor has questioned the application of allocation of costs and the resolution(s) of the matter(s) in question.

Response:

Neither internal nor external auditors have provided any comments on the criteria used to allocate costs. While the auditors have not commented, they are aware of how costs are allocated and have not raised any concerns. Both the shared services and corporate services methodology were reviewed by KPMG in 2009 as part of the Utilities' 2010-2011 Revenue Requirements applications.

6. Please provide the report of the most recent study/review of overhead/common costs.

Response:

Please see Attachment 6, which is the Shared Services Review prepared for FEI and filed as part of FEI's 2010-2011 Revenue Requirements Application.

7. Please provide the most recent segmented financial statements of the individual entities before consolidation as reported in FortisBC Holdings Inc. Consolidated Financial Statements for the years ended December 31, 2011 and 2010. In particular, the FortisBC Energy Inc., FortisBC Energy (Whistler) Inc., and FortisBC Energy (Vancouver Island) Inc.

Response:

Attachment 7a contains the 2011 financial statements for FortisBC Energy Inc. which are publicly available documents filed on the Canadian Securities Administrators System for Electronic Document Analysis and Retrieval (SEDAR) website.

Attachment 7b contains the 2011 financial statements for FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. which are being filed confidentially with the Commission only. Both FEVI and FEW consider their financial statements to be commercially sensitive and their corporate policy is to maintain confidentiality over non-public financial information.

8. Please provide the details of the allowed rate of return calculations that were used in the proposed revenue requirement effective rates vs. proposed FEI Amalco Effective rates presented to the Rate Design Application Workshop April 30, 2012.

Response:

Please see the table below for the rate of return calculations as presented in the workshop on April 30, 2012.

Rate of Return Calculation
Appendix J-1, Schedule 3

Line	Particular	Notes	Company				
			FEI	*FEVI*	*FEW*	*FN*	*RDA Application*
1	Equity %		40.00%	40.00%	40.00%	40.00%	40.00%
2	Return on Equity		9.50%	10.00%	10.00%	9.50%	9.62%
3	Equity Component	*Line 1 x Line 2*	3.80%	4.00%	4.00%	3.80%	3.85%
4							
5	Long Term Debt %		56.06%	42.91%	48.37%	55.66%	53.11%
6	Long Term Debt Rate		6.87%	5.85%	5.11%	6.88%	6.68%
7	Long Term Debt Component	*Line 5 x Line 6*	3.85%	2.51%	2.47%	3.83%	3.55%
8							
9	Short Term Debt %		3.92%	17.09%	11.63%	4.34%	6.89%
10	Short Term Debt Rate		3.50%	5.00%	4.50%	3.50%	3.50%
11	Short Term Debt Component	*Line 9 x Line 10*	0.14%	0.85%	0.52%	0.15%	0.24%
12							
13	Total Return on Rate Base	*Line 3 + Line 7+ Line 11*	7.79%	7.36%	7.00%	7.78%	7.64%

Please also refer to Appendix J-1, Schedule 3.

9. Please provide the details of the "cost-of-service based agreements" reached in 2009, mentioned in notes to the consolidated financial statements for FortisBC Holdings Inc., for the years ending December 31, 2011 and 2010, under 2. Significant Accounting Policies, Regulation.

Response:

The "cost-of-service based agreements" are the 2010-2011 negotiated settlement agreements for FEI and FEVI, and the 2010-2011 revenue requirement decision for FEW. These are public documents and can be found on the BCUC website at the following addresses:

FEI

http://www.bcuc.com/Documents/Orders/2009/DOC_23734_G-141-09_TGI%202010-2011RR-NSP-Settlement-Agrmnt.pdf

FEVI

http://www.bcuc.com/Documents/Orders/2009/DOC_23731_G-140-09_TGVI%202010-2011RRA_RDA-Settlement%20Agrmnt.pdf

FEW

http://www.bcuc.com/Documents/Orders/2010/DOC_26091_G-138-10_2010-2011_RRA-WEB.pdf

10. Please provide the details of the last provision for impairment of goodwill. How was this provision translated to cost of service, that is, how was it expensed to the various levels of service provided. Show in particular, what was attributed to transmission and delivery service cost.

Response:

None of FEI, FEVI or FEW has ever taken a provision for impairment of goodwill. Goodwill is considered a non-regulated item and does not usually enter a cost of service calculation.

11. Please explain how provision(s) for the post-employment benefit plans are allocated to operating expenses and asset costs.

Response:

Provisions for post-employment benefit plans are separated between those covering current service employees and those covering past service employees or retirees. The provision covering current service employees forms part of the labor loadings that are calculated to determine the 'fully loaded' salary of an employee which in turn drives their charge-out rate. In this fashion the provision covering current service employees will be charged to capital or operating expense based on the timesheets of employees. The provision covering past service employees is charged to operating expense only, as these costs have already vested.

12. Please provide the plans for recovery of alternative energy projects investment in the future. In particular, how will it affect the cost of service, either the midstream charge or the delivery charge?

Response:

As discussed in the response to BCUC IR 1.63.2.1, the government's energy policy and the needs and desires for some customers have resulted in the emergence of some opportunities for the FEU. Based on government energy policy and the needs of customers, the FEU have initiated its TES, NGT and Biomethane services, which have been brought to the Commission for approval in various applications.

TES is a separate class of service, or will be operated out of a separate entity. The significance of this structure is that the risks and revenues associated with TES are kept separate and as such investments in TES projects do not affect the cost of service for the natural gas class of service. However, there is an annual allocation of overhead costs from the natural gas class of service to the TES class of service that has the effect of reducing the delivery cost of service for natural gas customers.

NGT investments are currently offset by recoveries from NGT customers, all of which flow through the delivery charges of natural gas customers. FEU will maintain this approach until this issue is decided in the BFI Reconsideration that is currently before the Commission or with the AES Inquiry decision. FEU believe the current approach is the right one with regard to investment in NGT projects because it is expected to keep the cost of service relatively neutral. This is because the investments associated with NGT stations are generally recovered from NGT customers. However, NGT projects will reduce the delivery rates of natural gas customers over time as the additional throughput created on the system by these projects lowers delivery rates, all else equal.

The costs associated with making the Biomethane Program available to all customers are recovered from all natural gas customers through delivery rates; however, the cost of the biomethane supply, customer specific costs, and biomethane upgrading equipment are recovered through the commodity charge of those customers who elect into the Biomethane Program. This approach may be reviewed as part of the Biomethane Report that is due to the BCUC at the end of 2012. However, the BCUC also may give guidance to this issue in the AES Inquiry decision as this issue was canvassed in that proceeding as well.

13. Please provide details of how FortisBC Holdings' parent company Fortis corporate management services are allocated to operation and maintenance expenses of each utility. This is referenced in the notes (18. Related Party Transactions) to consolidated financial statements for FortisBC Holdings Inc. for the years ended December 31, 2011 and 2010.

Response:

As outlined in the FEU's 2012-2013 Revenue Requirements Application[1], the corporate management services are allocated from Fortis Inc. to FortisBC Holdings Inc. using assets as an allocator. The Fortis fee allocated to FortisBC Holdings Inc. is then combined with the local services provided to the three utilities and this total is then allocated to the FortisBC Energy utilities using the Massachusetts formula. The Massachusetts formula is in extensive use in industry and is composed of the arithmetical average of (1) operating revenue, (2) payroll, and (3) average net book value of tangible capital assets plus inventories. The use of these factors represents the total activity of all business segments as a means to allocate costs that are not directly assigned.

14. Please provide details of how interest charged to FortisBC Holdings by the parent company Fortis are allocated to the expenses of each utility. This is referenced in the notes (18. Related Party Transactions) to consolidated financial statements for FortisBC Holdings Inc. for the years ended December 31, 2011 and 2010.

Response:

The interest referenced in Note 18 of the FortisBC Holdings Inc. consolidated financial statements is the interest charged to FortisBC Holdings Inc. by Fortis Inc. on intercompany debt.

FEI and FEVI each have their own debt facilities and do not borrow from the parent company, FortisBC Holdings Inc.

FEW's financial arrangements with its parent company are described in Note 7 to its 2011 Financial Statements, included in the response to RRobinson IR 2.7. An excerpt from Note 7 is provided below (amounts in $000s):

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[1] FEU 2012-2013 RRA (Exhibit B-1), pages 267-273 http://www.bcuc.com/Documents/Proceedings/2011/DOC_28081_B-1_FEU-2012-2013-RRA-REDACTED-Public-Version-R.pdf

"The Corporation has operating credit facilities with a Canadian chartered bank through its parent company, FortisBC Holdings Inc. (FHI). The Corporation has a promissory note that was issued in 2009 for $8,000 and bears interest at 5.108%, payable semi-annually and is due on May 31, 2014. The long-term advance due to parent of $12,000 bears interest at 5.108%, payable semi-annually and is due on May 31, 2014."

15. Please provide the basis for the difference between rates for basic charge among the residential, small commercial, and large commercial customers.

Response:

This response also replies to RRobinson IR 2.16.

Ultimately, the basis of difference in rates between any class of customers or between similar types of customers results from a decision of the BCUC. In arriving at a decision the Commission will take into consideration the evidence that deals with balancing multiple principles/objectives, including those set out on page 189 of the Application.

Delivery rate differences between customer groups are influenced by the differences in costs that are attributable to those customer groups. One measurement that the Company and the Commission has used over the past two decades to assess the adequacy of revenues from a customer class compared to its allocated cost of service is the revenue to cost ratio. As a guide, the Company and the Commission have historically viewed a revenue-to-cost ratio that is between 90% and 110% as being sufficient; if a result is below or above this range it might be necessary to adjust the customer class rates to generate additional or lower revenues to be in closer alignment to the embedded cost to serve that customer class.

Specifically, the Basic Monthly Charge contributes to the recovery of fixed customer related costs. The variance in the rates charged between residential, small commercial and large commercial customers is influenced by the differences in the cost of service line and metering equipment and customer-related operating costs, where the lowest are for residential customers and highest are for commercial customers.

16. Please provide the basis for the difference between rates for delivery charge among the residential, small commercial, and large commercial customers.

Response:

Please refer to the response to RRobinson IR 2.15.

17. Please provide the basis for the difference between rates for midstream charge among the residential, small commercial, and large commercial customers.

Response:

The midstream cost recovery rates calculated for the amalgamated entity under the common rates proposal within the Application are based on the midstream costs being classified as demand-related costs, which is generally consistent with how midstream cost recovery rates are currently calculated for FEI. Demand-related costs, such as the midstream costs in this case, are associated with resources that are required and utilized to meet maximum daily gas flow requirements under peak demand.

The midstream costs are allocated to the various customer rate classes based on a load factor adjusted volumetric basis. The load factors are a relative measure of how efficiently each rate class utilizes the system, where the load factor is calculated as the ratio of the average daily consumption to the peak day consumption.

In general, the lower load factor rate classes are associated with consumption demand that is more temperature sensitive and these customer rate classes are assigned a higher proportion of the midstream costs; the residential customer rate class has a lower load factor than the commercial customer rate classes, and the small commercial customer rate class has a lower load factor than the large commercial customer rate class.

18. Please provide the latest load forecast for FortisBC (Vancouver Island) Inc. ., also the actual history for the last five years.

Response:

The following table provides normalized demand for FEVI from 2007 to 2013. 2012 and 2013 are the latest load forecast as filed in 2012/2013 Revenue Requirement Application.

FEVI Normalized Demand

(In PJs)	2007	2008	2009	2010	2011	2012F	2013F
Residential	4.6	4.7	4.6	4.7	4.6	4.6	4.5
Commercial	7.5	7.3	7.2	7.1	7.1	7.2	7.3
Tranportation	23.3	22.3	18.9	19.5	22.3	22.3	22.3
Total	35.4	34.3	30.7	31.3	34.0	34.1	34.1

19. Please provide the latest load forecast for FortisBC(Whistler) Inc., also the actual recent history up to five years.

Response:

The following table provides normalized demand of FEW from 2007 to 2013. 2012 and 2013 are the latest load forecast as filed in 2012/2013 Revenue Requirement Application.

FEW Normalized Demand

(In PJs)	2007	2008	2009	2010	2011	2012F	2013F
Residential	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Commercial	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total	0.7	0.7	0.7	0.7	0.7	0.7	0.7

20. Please provide the latest load forecast for FortisBC Energy Inc. ., also the actual history for the last five years.

Response:

The following table provides normalized demand of FEI from 2007 to 2013. 2012 and 2013 are the latest load forecast filed in 2012/2013 Revenue Requirement Application.

FEI Normalized Demand

(In PJs)	2007	2008	2009	2010	2011	2012F	2013F
Residential	70.6	68.8	69.9	70.0	69.9	69.8	69.8
Commercial	45.4	45.7	47.1	46.5	46.6	46.9	47.2
Industrial	60.0	55.3	48.4	51.5	51.2	51.5	51.6
Total	176.0	169.8	165.4	168.0	167.7	168.2	168.6

21. Please provide the planned sources of natural gas for the year 2012.

Response:

The FEU have a diversified natural gas portfolio that is designed to provide cost effective security of supply to its core customers each day under different weather conditions. Therefore, the FEU purchase and source supply from a variety of sources that include regional hubs such as Station 2, Sumas, AECO-NIT, and Kingsgate. Overall, approximately 85% of FEU's natural gas supply is sourced directly or indirectly in north-east British Columbia and the remaining 15% in Alberta.

Attachment 2

PART TWO: MANAGEMENT OF COSTS AND RATE DETERMINATION

A. INTRODUCTION

32. In developing the RRA, the FEU relied on an established budgeting process that incorporated significant management oversight from the FEU's recently integrated management team. In this Part, we outline the evidence on:

- the budgeting process;
- the independence of the budgeting process from the Balanced Scorecard approach used to assess performance and at-risk compensation;
- the ongoing benefits of savings achieved during PBR; and
- trends that demonstrate that the FEU have successfully managed costs.

The FEU submit that the evidence described below demonstrates that an appropriate and accountable management structure is in place. The budgeting process undertaken by the Companies supports the reasonableness of the forecasts upon which the proposed rates are based.

B. DIRECTION AND OVERSIGHT OF BUDGETING PROCESS

33. The FEU's management structure is outlined in section 3.1.1 of the Application. The FEU's ELT is ultimately responsible for utility management and budgeting, which is done through the UOC at the operational level.

34. The ELT, comprised of the President and Vice Presidents, is directly responsible for providing overall leadership and strategic guidance. Under the combined leadership structure, as before, the ELT provides the strategic direction for the Companies and develops the business plan in support, including the setting of the performance targets. The ELT works closely with, and guides, the UOC to ensure that business goals and objectives are achieved.[43]

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[43] Exhibit B-1, p. 30.

35. The UOC is comprised of senior managers representing the different departments within the Companies.[44] The UOC reviews and approves capital budgets, including all information technology projects, develops O&M budgets, and monitors and manages actual O&M expenditures during the year.[45]

36. Mr. Walker, who is directly involved in the budgeting process via his position on ELT, testified to the dedication of the management team in managing costs of the business. He stated, for example:

> …we constantly focus on productivity, whether we're in or out of PBR, as we drive our business forward. And again, I believe it's just a good way, if you're going to have a sustainable business, that you have to continue to focus on being better at it, and finding a way to deliver your services without just driving incremental costs. You've got to find a way to mitigate that as you go forward.[46]

The evidence of the comprehensive budgeting exercise undertaken by the FEU, discussed next, supports Mr. Walker's conviction.

C. ITERATIVE BUDGETING PROCESS: MODIFIED ZERO-BASED AND TRENDING

37. The evidence discussed below demonstrates that the capital and O&M budgets are prepared iteratively under the direction of the ELT based on practices and methodologies appropriate for the nature of particular departments and costs.

(a) Capital Budgeting Process

38. The Companies continue to manage the capital expenditures using defined capital approval policies and management processes. Capital funding requests are prioritized and approved taking into consideration safety and reliability requirements and ensuring that capital is put to its best use while minimizing the impact on rates.[47] The Capital Approval Policy outlines responsibilities and approval limits. It provides that annual capital budgets are

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[44] Exhibit B-1, pp. 30 to 31.

[45] Exhibit B-1, p. 39.

[46] Walker: T2, p. 190, ll. 13 to 21.

[47] Exhibit B-1, p. 38.

reviewed and approved by the UOC and the ELT. Capital projects are reviewed again before spending occurs to re-confirm the appropriateness of estimates and availability of staffing and resources.[48] Large capital projects subject to a CPCN are reviewed by the Board of Directors.[49] IT projects require approval of the UOC regardless of dollar value.[50]

39. The distribution and transmission operations are the most capital intensive areas of the business. The 2012-2013 RRA reflects the work that has been done to combine the Distribution and Transmission groups to permit more effective deployment of capital. As explained by Mr. Bell:[51]

> The efficiencies that we will find [from the reorganization of Transmission and Distribution into a single Operations department] will be in better use of capital, making sure in fact that, you know, we are utilizing the capital where it's most required. A common approach to asset management and the fact that we're going to be able to use the same criteria whether it's an intermediate pressure line on the distribution side of the business or a transmission line on the transmission side of the business, because both of those assets are regulated by the Oil and Gas Commission.

40. In summary, the capital budgets for 2012 and 2013 reviewed and approved by the UOC and the ELT are based on proven methodologies using the best known information and represent the capital spending needed to address the required safety, reliability, operational and customer requirements at a reasonable cost.[52]

(b) O&M Budgeting Process

41. Policies and processes are also in place for O&M. Two features of the O&M budgeting process were emphasized by the witnesses during the hearing:

- The budgeting process is bottom-up and iterative, rather than top-down; and

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48 Exhibit B-1, p. 39.

49 Exhibit B-1, p. 39.

50 Exhibit B-1, p. 39.

51 Bell: T7, p. 1068, ll . 7 to 16.

52 Exhibit B-1, section 6.2; Exhibit B-6, BCOAPO IR 1.10.1, 1.10.2, 1.11.1.

- The FEU employ various budgeting techniques, such as zero-based budgeting or trend-based budgeting, that reflect the nature of the work performed in specific areas of the business.

42. Mr. Walker described the iterative process and its benefits as follows:

> …But what we do do is that through -- as we move down the levels, because it's a bottom up, top down, bottom up kind of sort of iterative process that we go through, and the various functional areas, vice presidents and directors, are tasked to challenge and support at each level the resources that they need dollar-wise and people-wise to move forward with the various programs. So when they eventually get discussed at the executive table, I'm hearing from all the various departments. And what we'll get them is a sense of yeah, that'll be great to do and it's important but not right now, and we need to massage that. And that would -- the number of people that we would require to do that would follow that sort of discussion.[53]

43. The UOC reviews existing O&M budgets to ensure their appropriateness and continued justification. Incremental O&M funding requests are prioritized and approved taking into consideration safety and reliability requirements and ensuring that funding is put to its best use while minimizing the impact on customers' rates.[54] Mr. Dall'Antonia discussed the types of budgeting approaches employed, explaining that in areas where the levels of activity vary materially from year to year the Companies revisit the existing budget to a much greater degree. Trend-based budgeting is used to a greater extent in circumstances where the level of activity is steady and predictable year over year:

> MR. DALL'ANTONIA: A: I think Mr. Walker's comment about we don't do zero based budgeting, I think what he was referring to is a cross-organization, a true zero based, where you basically go back to first principles every year. Throughout the organization there are elements of zero-based budgeting.
>
> I think what we would call our approach is more of a hybrid approach, where trending or incremental budgeting versus zero base work together.
>
> Certain areas of our business do use more zero base budgeting because they're more activity based. Mr. Bell, when he's up here, he runs transmission and

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[53] Walker: T2, p. 258, ll. 3-21.

[54] Exhibit B-1, p. 39.

> distribution, which is effectively the largest component of the business. His group, he oversees the budgeting as the EP [sic - VP] of that area. They tend to do something that is much closer to zero based, where they look at activity view, they look at what projects or activities they'll undertake in the next two years versus ones they won't.
>
> For instance, every year we have a certain budget for rights of way clearing. Some years it's higher, some years it's lower. You don't just assume that you've got a line for rights of way clearing and it just goes up with inflation. Seismic assessments, single point failure assessments, code compliance, those can vary year to year, as well as based on growth, based on system integrity planning, activity in certain areas do change. So there is an element, or a much greater element of zero base budgeting in that process.
>
> So you look at say the finance and regulatory group, our work tends to be much more routine and constant. So you can look at individuals, you can look at specific external contracts, but it's much easier to do a trending, if you will, in those areas of the business.
>
> Overall, the UOC, they put together a budget working group, and department managers are asked to look at their budgets from point of view of take last year's, the last number of years from an experiential point of view, see what you're not going to be doing, get to what we'd call a baseline, and then justify any increases to that. So it is a mix of what we'd call zero-based and incremental.
>
> But again, given the fact that we've been at this for a number of years and we know our business very well, the value in going to a zero-based each year for the incremental benefit would not justify having to redo budgets at that level. If that answers the question.[55]

44. A more zero-based approach is key in activity-driven budgets to ensuring that the existing budget is still warranted. The Transmission & Distribution division has, by far, the largest budget among the divisions, and employs that zero-based approach. Mr. Bell characterized the approach as follows:

> MR. BELL: A: If I can -- now, I can talk to my specific area within the organization, and we are what I would call as close to zero base budget as I think you can get. So asset management at the beginning of the budgeting process determines exactly how many units of each type they want to have surveyed or repaired or inspected during the year. We then overlay the costs for the previous period on top of that, which gives us our budget.

[55] Dall'Antonia: T5, p.689 l. 12 to p. 691, l. 9.

> So, the only areas that have what I would call a bit of flex in are the areas of training and what I call idle time. So, idle time would be time that we don't have any construction activities or operating activities in a smaller district. And so we have people that are available for emergency response, and that's what they're there for. Or if we have -- and again in the training side of things, we have what's called mandatory training. We have to get it done during that year. But we will have programs that are not mandatory. They do give us a bit of flex. An example of that would be training a crew person who normally does service line installation or emergency repair to do meter-read calls, so that we can utilize them when a crunch hits our meter-read calls.
>
> So, there -- those two areas we budget by person and by time available. The rest of it is done with the field staff, it's done on a per-unit basis.[56]

45. Mr. Bell also explained how the centralized approach within the Operations department (the largest within the FEU) captures savings that get reflected in the divisional budget:[57]

> Our entire system is laid out in a manner that allows us to plan the work, do the work, and then complete it and review it, and so we do that on a continual basis. We almost look at that as the price of admission, I guess I would say.
>
> … Yeah, and again, I think it's probably because certainly within my group, we look at that through everything we do. As an example, when we have somebody do a valve check, that goes into our system. The costs are recorded. We have a key contact that reviews that across the province. They take the highs and the lows. They have a look at that. The reason we do that is you may have a group of people that can do a product very very low, and at the end of the day they are not completing it as per the codes or standards. And so we want to find out if they found a better way to do it, to make sure they're doing it correctly. And then same with the highs, you know, what caused it to be high, and we can review that right down to the employee level.
>
> So we do spend a lot of time in this area within my group.

46. The process of revisiting the activity based budgets each year on a zero-based approach ensures that past productivity gains are passed along to customers.[58] However, the

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[56] Bell: T6, p. 986, l. 17 to p. 987, l. 19.

[57] Bell: T6, p. 984, ll. 22 to 26 and p. 985, l. 13 to p. 986, l. 3.

[58] Bell: T6, p. 984, l. 22 to l. 26, p. 985, l. 13 to p. 986, l. 3 and p. 988, l. 14 to p. 990, l. 18. Mr. Weafer, in addressing this point with Mr. Bell during cross-examination, observed that the word “productivity” only occurs 7 times in the Application: p. 985, ll. 7-12. Examples of savings and productivity improvements, however, are

FEU are able to use knowledge acquired from past years to make the budgeting process more efficient in areas where zero-based approach would add little value. Those areas include finance and regulatory,[59] and other similar areas in the Companies where costs are not as subject to variability according to individual units of work.[60] On the whole, this hybrid approach undertaken by the FEU applies the necessary rigour and is cost-effective for customers.

D. BALANCED SCORECARD INDEPENDENT OF BUDGETING ACTIVITY

47. In this section, we distinguish the Balanced Scorecard approach from the budgeting process. The Balanced Scorecard is a management tool to assess the performance of the utilities. It contains performance measures that are designed to align the interests of the shareholder, customers and employees in terms of how the utilities carry out the business.[61] As described below, the Balanced Scorecard neither acts as a substitute for, nor detracts from, the budgeting process described previously. The role of the Balanced Scorecard in determining employee compensation is addressed later in these submissions.

48. There were a number of information requests and questions in cross-examination which appeared to suggest that the Balanced Scorecard improperly motivates the FEU or the executive to "to pursue growth in O&M budgets"[62] or inflate rate base.[63] However, the Balanced Scorecard, by design, could not have that effect because the targets are not set until after the Commission's decision in the RRA.[64] The financial target in the Balanced Scorecard is concerned with the shareholder's opportunity to a fair return as approved by the Commission. The Financial category (including the target for net earnings) incorporates the approved costs and revenues that are utilized in determining customers' rates each year. For the Customer category, the O&M and Base capital amounts are the same O&M and Base

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detailed throughout the Application. While word counts have questionable relevance in terms of evaluating the FEU's budgeting process, we observe that words synonymous with productivity are pervasive in the Application. Mr. Bell's evidence on the budgeting process should be preferred to word counts.

59 Dall'Antonia: T5, p. 690, ll. 16 to 21.

60 Bell: T6, p. 986, l. 17 to p. 987, l. 19.

61 Exhibit B-17, BCUC IR 2.123.5. The FEU scorecard results are provided in Exhibit B-6, BCOAPO 1.7.2.

62 Exhibit B-17, BCUC IR 2.123.6

63 Thomson: T3, p. 489, ll. 14 to 25.

64 Exhibit B-17, BCUC IR 2.123.6.

21.0 Reference: Cost of Service

Exhibit B-9, BCUC IR 1.54.1, pp. 166-167

Exhibit B-1, section 5, p. 174

Distribution – Costs driven by activity or unit cost changes

"The Field Service Delivery budget is the largest component of the Distribution budget at $20.8 million. Incremental increases in O&M of $416 thousand in 2012 and $272 thousand in 2013 are required in the category of Service Standards and Reliability for field service delivery activities. The changes in budget requirements are caused by changes in activity levels and unit costs." [Ref: B-1, Section 5, p. 174]

The attachment for the response to BCUC IR 1.54.1 does not contain the historical information to explain the increases of $416,000 in 2012 and $272,000 in 2013 for the field service delivery activities of Mainland or the increases of $353,000 in 2012 and $72,000 in 2013 for Vancouver Island.

21.1 Please provide the historical detail from 2006 through 2011 for the increases in field service delivery activities.

Response:

Attachment 21.1 contains are two Excel files (Attachment 21.1a for FEI and Attachment 21.1b for FEVI) which provide the historical detail requested for 2006 through to 2013 for the Field Service Delivery Activities. The spreadsheets present the total budgets for Field Service Delivery activities including items in the Service Standards and Reliability category and any other category, and therefore do not tie to the $416,000 and $272,000 (Mainland) and $353,000 and $72,000 (Vancouver Island) increases mentioned in the preamble to the question.

The format of the spreadsheets is essentially a listing of all field service delivery cost centres, description of major category (i.e. leaks repairs), description of sub-category or Maintenance Activity Type ("MAT") (i.e. DP main, IP main, LP main, Services, etc.), forecast ("plan") dollars for 2011-2013, actual dollars for 2006-2010, activity count where applicable and unit cost where applicable for each line item. Several row sub-totals are used throughout to summarize the major cost centre groupings (i.e. preventive maintenance, corrective maintenance, operations, meter exchange, emergency management services, meter to cash residential, and meter to cash industrial).

The budget methodology used for Field Service Delivery cost centres is essentially activity based budgeting (i.e. number of forecast activities multiplied by the forecast unit cost equals forecast budget). Year over year changes to labour and vehicle charge-out rates are then flowed through to the forecast unit costs in the various cost centres where these types of resources are utilized.

In terms of the number of Field Service Delivery activities, there are 46 cost centres in FEI and a duplicate set in FEVI and within those cost centres there are approximately 110 budgeted MAT types. Within one of the more broadly defined MAT types (i.e. cost centre 2590, Operations General, MAT type "STN" for regulator stations), there is an additional level of detail with 11 sub-categories beneath the MAT type level.

Units of activity are forecast for each MAT type where possible either based on scheduled maintenance or historical levels or combinations thereof. Unit costs typically are based on the most recent year"s historical experience or longer trends where data is more reliable.

A portion of the field services delivery cost centre request is related to inflation and accordingly included in the overall inflation dollars identified in Table 5.3-17 (Exhibit B-1 page 171) for FEI and Table 5.3-18 (Exhibit B-1 page 177) for FEVI. The 2011, 2012 and 2013 forecasts ("plan") included in this response for Field Service Delivery cost centres include IBEW labour and vehicle rate changes which include contractor and wage rate inflation, employee benefit and concession rate changes and vehicle rate changes.

Attachment 21.1

REFER TO LIVE SPREADSHEETS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 4

THE FORTISBC ENERGY UTILITIES

(comprised of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.)

2012-2013 Revenue Requirements and Rates Application

Volume 4

Attachments to the Response to BCUC Information Requests No. 1

June 30, 2011

Attachment 99.1

INTRODUCTION

1.1 Contents of the Manual

Chapter 1: Introduction

Overview of contents, purpose and audience

Chapter 2: Capitalization Policy

Outlines the minimum capitalization level and policy issues by category

Chapter 3: Capital Expenditures Control

Describes the Approval Levels and the policies related to controlling capital expenditures

Chapter 4: Plant In Service and Retirements

Outlines the policies related to custody, care, transfers and retirements of capital assets

Chapter 5: Depreciation

Describes the depreciation process for various types of assets

1.2 Purpose of the Manual

This manual has been prepared to provide guidelines for accounting and field personnel, and to document accounting standards at Terasen Gas. Use this manual to:

- determine which expenditures can be capitalized and which should be expensed
- learn about capitalization policies related to plant additions, transfers and retirements; including the application of overhead, allowance for funds used during construction and depreciation
- ensure that capitalized expenditures are appropriately authorized, recorded and controlled
- describe the administration in caring for and maintaining custody and control over the Company's capital assets
- identify the accounting classification of gas plant in service, work in progress and other gas plant
- follow prescribed procedures to help you with the process of capital expenditure control and to maintain adherence to capitalization policies

1.3 Audience for the Manual

This manual should be read and complied with by all Company personnel who are involved in the construction, acquisition, maintenance, removal and disposal of capital assets.

CAPITALIZATION POLICY

2.1 Introduction

This chapter covers the capitalization policies related to the capital additions acquired or constructed, defining capital versus maintenance expenditures, the basis of capital costs, and the classification for certain types of capital expenditures.

Matching Costs

Terasen Gas policy is to distribute expenditures as equitably as possible among present and future customers by matching capitalized costs to the accounting period in which associated benefits accrue. This is accomplished in accordance with the Company's depreciation/amortization practices, which are subject to BCUC regulations.

Capitalization

All costs associated with the acquisition and construction of capital assets are capitalized.

Capital Asset

Expenditures are classified as a capital asset following these criteria:

- the expenditure must provide, or contribute, benefits to Terasen Gas for a service life greater than one year
- the expenditure must result in, or contribute toward, acquisition of an economic resource or asset over which Terasen Gas has a legally enforceable claim to a service potential, right or specific benefit. Terasen Gas must also control the asset
- the expenditure must be expected to result in, or contribute toward, a benefit which leads with a reasonable degree of certainty to recover through potential sales of service or products, or which is required to meet safety or governmental regulations
- the expenditure must meet the minimum capitalization level requirements

2.2 Minimum Capitalization Level

Minimum Level

For direct costs incurred in acquiring or constructing the addition or replacement of a PRU which falls into one of the categories, is capitalized if the cost of the PRU exceed the specified limits:

	Minimum $
Tools and equipment	1,000
Furniture and equipment	1,000

Purchased computer software/hardware	1,000
Other general plant equipment	1,000
In-house developed computer software and/or based on assessment of individual projects	10,000

Concept of PRUs

The concept of Property Retirement Units (PRUs) is defined in the Company's PRU Catalogue. The PRU Catalogue is an integral part of the Capitalization Policy.

2.3 Capital Versus Maintenance

PRU Additions

The PRU outlines/describes the lowest level of expenditure for capitalization purposes for a unit of property in the asset subledger.

Maintenance

Items smaller than a component outlined/described in the PRU or an item whose acquisition cost is lower than the minimum capitalization level is charged to maintenance.

Expenditure on Existing PRUs

Expenditure on existing PRUs in service are capitalized if the expense results in:

- a replacement of the entire PRU or
- a substantial improvement or betterment of the PRU

Classification of Expenses

Expenditures during ownership of capital assets are classified as:

- maintenance and repairs
- improvements and additions
- rehabilitation/major renewals
- replacements and retirements

these expenditures are defined in further detail below to set them apart and to distinguish the cost as capital or a maintenance charge.

2.3.1 Maintenance and Repairs

Concept

Maintenance costs are expenditures made to keep the asset in good condition (preventive); while repair costs are made to put the asset back into good working condition (curative).

Does not Affect

Maintenance and repair costs are not expected to prolong the normal life of an asset (PRU), or materially add to its service value. As no additional benefits are anticipated, the costs of maintenance and repairs are charged to maintenance in the current accounting period.

2.3.2 Improvements and Additions

Substantial Betterments

Improvements or substantial betterments refer to capital expenditures on existing PRUs which:

- materially add to the service value of the PRU(s); or
- materially extend the normal service life of the PRU(s)

Increase in Service Value

The service value of a PRU may be increased through expansion and extension where there is an increase in the physical size of an asset. For example, a new wing is added to a building or more equipment is added to an existing capital asset.

Increase in Service Life

The normal service life of a PRU is increased through substitution where there is an increase in the quality of an asset. For example, paving a gravel parking lot increases the quality of an existing asset.

Consult Asset Accounting

When in doubt about each case in Section 2.3, consult Asset Accounting to assist you in deciding the appropriate accounting treatment.

Significant cost and long life do not by themselves decide that a replacement cost can be capitalized; e.g. the cost to replace a roof with the same kind of materials is accounted for a maintenance expense.

2.3.3 Rehabilitation/Major Renewals

To Restore

Expenditures to restore or improve buildings or equipment purchased in a rundown condition (e.g. second-hand plant), with the intention of rebuilding, can be charged to capital assets as part of the cost of acquisition, provided that;

- the costs of renewals, which means the costs of material (other than excluding second-hand parts remaining in the rebuilt PRU), plus the cost of labour used in the rebuilding process, exceeds fifty percent (50%) of the replacement cost of a new plant unit of the same kind and class
- the costs of dismantling and/or repairing old parts reused, are excluded and charged to expense

- the rebuilt plant unit (PRU) is accounted for as a capital addition, and the old plant unit PRU is accounted for as retired from service

2.3.4 Replacements and Retirements

Complete PRU

Replacement of a complete PRU:

- the original cost of the old asset (PRU) is retired and the cost of the new item is capitalized

Part of PRU is Maintenance

Replacements of parts and (less than a PRU):

- the costs of replacing parts and components of a PRU is accounted for as maintenance expense. Replacements of parts and components here means to restore the PRU to its original condition, and keep it in efficient operating condition

Extensive Replacement

Extensive replacements of part (less than a PRU) could be considered as capital improvement/substantial betterment.

The cost incurred to replace components or part of a PRU, which according to government or agency regulation creates a health or safety hazard, does not automatically qualify for capitalization. Such projects must meet the 'substantial betterment' criteria on an individual PRU, project/location basis.

In each case, please consult Asset Accounting.

2.4 Basis of Cost

At Cost

Expenditure for capital assets are recorded at the historic cost to Terasen Gas. Cost includes direct expenditures related to the acquisition/construction as well as a proportionate allocation of overhead and, where applicable, allowance for funds used during construction charges.

Construction by Terasen Gas

- If the capital asset is constructed for or by Terasen Gas, the construction costs including labour, material and supplies, contract work, special machine and heavy work equipment service, insurance, normal levels of damages, privileges, a proportionate allocation for overhead, and where applicable, allowance for funds used during construction.
- When a project necessitates the purchase of PRU equipment items such as office equipment, heavy work equipment, transportation equipment to be used exclusively for the project, the cost of such equipment is, for the

duration of the project, charged to construction, subject to approval by Asset Accounting.

Surplus-to-Project Material

- When a project is completed, surplus inventory items, considered re-usable, are returned to stores by crediting the project at the prevailing inventory unit cost.
- Non-inventory items that can be identified:
  - for future project use, scheduled to begin with two years are taken into Central Stores by crediting the project at fair market value; or
  - as office, heavy work or transportation equipment which were initially purchased exclusively for project use and now considered re-usable as general plant equipment, are transferred from WIP account to plant-in-service at fair market value, provided it meets the minimum capitalization level. If it is not considered re-usable as general plant equipment, it must be disposed of through re-sale and the proceeds credited to the project.

2.5 Capitalized Overhead

Cost Classification

Costs which cannot be directly identified with individual construction projects are collected by a cost centre and classified as operating /maintenance expense or capitalized overhead.

Allocation Predetermined

Overhead will be capitalized on the basis of predetermined rates established by Finance and reviewed annually, to ensure that the apportionment of Operating and Maintenance expense to capitalized overhead is reasonable and consistent.

Capitalization rates will be calculated annually by Finance, based initially on budgeted costs with revision at year end, to actual costs where the change is considered to be material.

Certain administrative/common costs are capitalized at fixed maximum rates, which do not vary with construction levels and will not be recalculated annually.

Distributed to Plant

The resultant overheads capitalized are charged monthly to GL account 10098 (Overhead Charged to Construction).

Plant Not Applicable

Overhead is NOT applied to:

- removal/dismantling costs
- general plant capital additions
- 47810 Meters
- CPCN projects

2.6 Allowance for Funds Used During Construction (AFUDC)

Policy

AFUDC is capitalized on projects under construction whose costs are greater than $50,000 each and which are expected to take three (3) or more months to construct. AFUDC is the cost of capital that is the cost of borrowed funds and a reasonable rate on other funds such as equity, used for the purpose of construction.

Rate Determined

The AFUDC rate is the return on rate base for Terasen Gas as approved by the BCUC.

AFUDC Applied

AFUDC is applied to both specific and certain recurring plant expenditures based on previous month-to-date total direct and overhead costs, less contributions in aid of construction received, if any.

AFUDC Begins

AFUDC will commence on the date the project work commences and ends when the project is placed into service For further information, refer to AFUDC documentation.

Preliminary Charges

Refer to section 2.8.2 below.

Adjustment

AFUDC applied to specific projects, may be subject to recalculation or reversal, if the AFUDC criteria is not met or the AFUDC rate is adjusted.

AFUDC Not Applied

AFUDC is not applied on expenditures in the following capital asset classifications:

- capital assets in service
- capital assets held for future use
- capital assets held for resale
- research, development and preliminary engineering
- projects with budgeted costs less than $50,000

- projects which are expected to be completed in less than three (3) months

2.7 Contribution In Aid of Construction

Source of

Consists of contributions or grants in cash, service or property from governments or government agencies, corporations, individuals and others for contributions in aid of construction and other purposes.

Refundable Contribution

Customers' Advance for Construction, G/L Account 25501 is reviewed at least annually by Finance, and any balance remaining by customer according to agreement or rule, shall be reclassified to contribution in aid of construction

Accounted for

The gross costs of the capital asset constructed is charged to the appropriate Gas Plant in Service account with a contra 21101 account to offset, the contribution in aid of construction.

From Billable Work

Recoverable costs, from billable work capitalized as capital additions, are accounted for as a contribution in aid of construction.

2.8 Classification of Capital Expenditures

Reason for

Certain types of expenditures warrants explanations in respect of capitalization policy, because of their function purpose and unique characteristics they are:

- computer software
- land
- leased property
- leasehold improvements
- pipeline – relocations and replacements
- major inspections and overhauls
- spare parts
- gas plant held for future use
- gas plant not in rate base
- deferred projects
- abandoned projects
- property taxes

Each of these are described below.

2.8.1 Computer Software

Purchased

Purchased computer software is capitalized according to the minimum capitalization level; See Capitalization Policy, Minimum Capitalization Level, Section 2.2.

In-House

The cost of in-house developed software will be considered for capitalization in accordance with the Capitalization Policy, Minimum Capitalization Level, Section 2.2.

- or based on an assessment of the individual project, it will include the cost of designing programs and implementing the system

2.8.1.1 Costs excluded from capitalization

Costs that are no longer capitalized and should be expensed include:

- development of training materials
- data conversion
- user training costs and
- feasibility costs

Enhancements

Subsequent enhancements are capitalized if:

- it meets the Improvement and Additions Criteria referred to under Section 2.3.2, and
- it meets the same minimum capitalization level set for in-house developed software

2.8.2 Land

Temporary Accounts

The cost of land is capitalized to plant and classified in one of the following accounts until it is placed in service:

- gas plant held for future use – when purchased with no immediate use
- work-in-progress – when purchased directly for, or transferred in from gas plant held

Cost Excluded

The costs of clearing, grading, leveling and surveying both before and after the construction are to be included in the cost of constructing the plant facilities and, therefore, are not to be included in the cost of the land.

Not-In-Service, Resale

Land that is not-in-service or removed from in-service for resale, is classified as Gas Plant Not In Rate Base; until sold

2.8.3 Leased Property

Capitalization Criteria

Leases are capitalized if the terms of the lease transfer substantially all of the benefits and risks of ownership related to the property from the lessor to Terasen Gas (lessee). There are no restrictions on the term of capitalized leases.

Transfer of Ownership

Ownership passes to Terasen Gas at the inception of the lease provided one or more of the following conditions are present:

Time of Transfer

- the terms of the lease provide that ownership of the leased property passes to Terasen Gas by the end of the lease term, or the lease provides for a bargain purchase option minimum $500 per PRU

Receive Economic Benefits

- the lease term is of such a duration that Terasen Gas will receive substantially all the economic benefits expected to be derived from the use of the leased property over its useful life (when lease term exceeds 75% of useful life)

Returns Assured

- the lessor would be assured of recovering the investment in the leased property and of earning a return on the investment as a result of the lease agreement

Leases Less Than $10,000

- for leases with payments over the term totaling less than $10,000 and where the asset is acquired at the end of the agreement or on buyout, the asset is recorded at the time of transfer of title to Terasen Gas

2.8.4 Leasehold Improvements

Criteria

A leasehold improvement exists when Terasen Gas leases property and incurs costs to make the property suitable for its use; e.g. offices, warehouses.

Capitalized When

Leasehold improvements are capitalized to the extent that:

- they exceed the owner's allowance by $500; and
- they provide benefits to Terasen Gas; and
- the term of the lease is in excess of 12 months

Types of Expenditures

Leasehold improvements

- office renovations to walls, floors and ceilings
- items permanently affixed to the structure
- non-salvageable, e.g. communication cables

Amortized

Leasehold improvements are amortized over the life of the lease and retired from plant in service when the facility is vacated.

2.8.5 Pipeline Relocations and Replacements

Pipe Relocations

Where a transmission or distribution pipeline of 20 or more continuous meters (65 feet) in length is relocated, that section changed is considered capital. The new line is a capital addition and charged to the appropriate capital asset. Where such a relocation results from action by a governmental authority, it will be accounted for in a similar manner.

Pipe Replacements

Where a transmission or distribution pipeline of 20 or more continuous meters (65 feet) in length is replaced for any reason, the original cost of the section removed is treated as a retirement and the total cost of opening and back filling the trench, as well as the installed cost of the new pipe is capitalized

Pipe Removed

A retirement entry is to be made for pipeline removed and/or abandoned due to a relocation or replacement. The costs of removing the retired pipe from the trench are accounted for as removal/dismantling costs.

Service Line Pipe

The costs of extending or shortening an existing service line is defined as an alteration and therefore capitalized. No retirement entry is made until the entire service line is removed or abandoned. Note however, that changes in as-built length must be updated accordingly.

Reconditioning

The costs of reconditioning pipeline not removed are charged to maintenance.

2.8.6 Spare Parts

Charged to Maintenance

Terasen Gas maintains an inventory of spare parts for its gas utility system. Spare parts generally are items comprised of less than a PRU and are, therefore, charged to inventory when purchased and expensed to maintenance when issued.

Types of Parts

Some spare parts, however constitute Retirement PRUs such as:

- spare modules for gas meters
- spare telemetry circuit boards

and are capitalized upon purchase and depreciated over the same estimated service life as the PRU to which they are related.

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2.8.7 Major Inspections and Major Overhauls

Major Inspections: are those considered to be undertaken to assess transmission or distribution infrastructure or other major asset infrastructure or equipment, for possible required capital improvements (including, but not limited to, all ILI) and thus should be capitalized and depreciated separately over the appropriate useful life to the next inspection rather than being expensed. The specific circumstances and facts pertaining to each type of inspection need to be considered. Some possible indicators that can assist in identifying additional major inspections could include consideration of the following (this is not an exhaustive list):

- Cost greater than $250,000, or
- Frequency greater than 1 year (eg. occurs once every 5 years), or
- Required by law or regulations as part of the safe operation of the related asset

The following types of inspections are considered to be "major inspections" as of the date of this memo and should be capitalized as a separate asset:

- In-Line Inspections (includes marine ILI)
- Marine Crossing Inspections (external)

Major overhauls may be required at regular intervals over the useful life of an item of property, plant and equipment, such as the compressor station equipment, to allow the continued use of the asset. The overhaul costs should be capitalized and depreciated separately over the appropriate useful life to the next overhaul rather than being expensed. The specific circumstances and facts pertaining to each type of overhaul need to be considered. Some possible indicators that can assist in identifying additional major overhauls could include consideration of the following (this is not an exhaustive list):

- Cost greater than $250,000
- Frequency greater than 1 year (eg. occurs once every 5 years)
- Required by law or regulations as part of the safe operation of the related asset

The following types of overhauls are considered to be "major overhauls" as of the date of this policy and should be capitalized as a separate asset:

- Gas Turbine Overhauls
- Gas Compressor Overhauls

Intangible Assets

Non-Physical

Expenditure which results in the acquisition of intangible (non-physical) assets, are capitalized provided that:

Provision

- the privileges obtained runs in perpetuity or for a specified term of more than one year; or
- the expenditure is necessary or valuable in the operation of the company and
- the expenditure are in excess of $10,000

Type of Expenditures

Types of tangible asset expenditures are:

- franchises and consents paid to governmental authorities
- patents, licenses, rights and privileges

2.9 Gas Plant Held for Future Use

How to Maintain

The costs of acquiring or constructing plant items for future use are capitalized and classified as Gas Plant Held for Future Use. This account should be maintained in such detail as though the plant were in service.

Qualification Criteria

In order to qualify as Gas Plant Held for Future Use, the plant item must be:

- a physical asset, at a minimum of $500 each
- not in-service or part of unfinished construction
- intended for a specific potential use within 20 years

Held for Resale

If the project is terminated and no other future use is planned, the physical plant items are held for resale at the lower of cost or market value and the gain or loss included in the other income accounts.

2.10 Gas Plant Not in Rate Base

Established By Regulation

Terasen Gas may acquire or construct plant items which are useful and beneficial to the company, but, according to BCUC regulations, are not to be included in the rate base. Such costs are capitalized but classified as Gas Plan NOT in Rate Base.

Detailed Records

Terasen Gas will maintain subsidiary records in which Gas Plant Not in Rate Base is subdivided according to the plant facility to which it applied and to each group of plant accounts.

Type of Expenditures

Gas Plant Not in Rate Base may include the following Capital expenditures:

- BCUC disallowances on cost capitalized in prior years
- corporate art
- premium costs paid on acquisition of other gas utilities, whose plant costs are to be involved in rate base

Disposition

The disposition of Gas Plant Not in Rate Base is reflected on the Income Statement as other income or other income deductions. Refer to Chapter 4, Gas Plant In Service, Section 4.4.3, for policy on premium cost retirements.

Deferred Projects

Criteria

A project is deferred if the scheduled in-service or turn-on date has been delayed by management decisions and the work is halted for more than one year.

Write-Offs

Appropriate write-offs may be made at the time of the deferral and in subsequent reviews where:

- specific obsolescence of some costs is identified; or
- changes in technology or environmental considerations may progressively diminish the usefulness and degree of certainty of recovery

Treatment of Assets Retained

Assets retained at the site may have to be mothballed. Costs of mothballing and maintenance costs during the deferral period as well as demothballing costs are all charged against operations when incurred, since no betterment of the asset has occurred.

2.11 Abandoned Projects

Written-Off

A capital project is considered abandoned when it is decided never to reactivate it again. The costs incurred to date, exclusive of AFUDC and physical assets remaining, are written-off as charges to operations, or if significant, to other income deductions.

Accounting For Physical Assets

Physical assets relating to abandoned projects are either:

- disposed of by resale
- returned to inventory
- transferred to other projects at market value, except where no market value exists in which case original costs will be used; or
- written-off if they have no alternative use or market value

2.12 Property Taxes

Paid on Assets

Terasen Gas pays property taxes, grants or percentage amount in lieu of general taxes on its assessable capital assets while they are in-service or held for future use.

Capitalized When

Taxes on capital assets under construction or on capital assets that are not yet ready for service are capitalized and charged to the appropriate work order or capital account.

Reporting Quantity Data

Operations managers will be responsible to report as required the quantitative data by capital district for Recurring Plant to Lands Department. This data is used to compute the assessable capital assets for property tax purposes.

Reporting Capital Data

Asset Accounting is responsible to accumulate and report capital additions and retirements of assessable capital assets to the Taxation department.

CAPITAL EXPENDITURE CONTROL

3.1 Introduction

This chapter covers the policies related to controlling capital expenditures during the capital acquisition or construction stage.

3.2 Authorization Of Capital Expenditures

Specific Approval Levels

Terasen Gas has established specific authority levels for approving Capital and Operating Expenditures as defined in the Company's Expenditure Authority Policy.

Budgeted vs. Non-Budgeted Items

These levels cover both budgeted and non-budgeted items. Approval authority for budgeted items may be delegated to immediate subordinates. Delegation is not allowed for non-budgeted items.

Types of Cost Monitoring Objects

The following types of objects are used to ensure that Capital expenditures are controlled:

- Internal Orders (I/O)
- Projects and Work Breakdown Structures (WBS)

Recurring and Specific Plant

The use of these objects warrants explanation with respect to the Capitalization Policy, because the capitalization of costs are classified between Recurring and Specific Plant; and variation in level of control is recognized.

Field Operations Responsibility

Recurring Plant expenditures are budgeted for and monitored by Operations.

3.3 Internal Orders (I/O)

Definition

Internal Orders are temporary cost objects used to track one-time events or recurring programs.

Types of Capital Internal Orders

- The types of Capital Orders are listed in the Budget Guidelines Manual, Section 7.1 Capital Expenditures. General Plant direct purchases
-

Internal Order Creation

It is the responsibility of each operating department to create internal orders to capture and monitor costs. Costs can be planned in the internal order for comparison between actual and plan. It is important that all mandatory fields are completed accurately and detailed descriptions are maintained so proper settlement rules can be completed.

Settlement Rule

Asset Accounting will enter settlement rules in the orders based on the information entered in the master data of the internal order record. The settlement rule specifies which asset will receive the costs collected in the internal order. Once the asset receives the costs, the asset goes in service.

Internal Order Status

There are four different statuses for an internal order, each allows for different processes to occur. In the created status planning and settlement rule maintenance is allowed. In the released status additional planning, settlement rule maintenance, actual cost posting and settlement to AUC is allowed. When the status is changed to technically complete (TECO) settlement rule maintenance, actual cost posting and final settlement is allowed. The order status is moved to close when all costs are processed and costs are moved to the final asset.

Additional Information

For additional information regarding the use of internal orders, please refer to the Budget Guidelines.

3.4 Projects and Work Breakdown Structures (WBS)

Definition

Projects and WBS Elements are temporary cost objects used to track one-time events or specific programs.

Project and WBS Creation

It is the responsibility of each project manager and or OFA/OFC with the assistance of Asset Accounting to create project definitions and WBS elements to capture and monitor costs. Costs can be planned in the WBS element for comparison between actual and plan. It is important that all mandatory fields are completed accurately and detailed descriptions are maintained so proper settlement rules can be completed.

Settlement Rule

The settlement rule specifies which asset will receive the costs collected in the WBS element. Once the asset receives the costs when the asset is in service. Asset Accounting will enter settlement rules in the project based on the information entered in the master data of the project record.

Project and WBS Status

There are four different statuses for a project or WBS element, each allows for different processes to occur. In the created status planning and settlement rule maintenance is allowed. In the released status additional planning, settlement rule maintenance, actual cost posting and settlement to AUC is allowed. When the status is changed to technically complete (TECO) settlement rule maintenance, actual cost posting and final settlement is allowed. The WBS status is moved to close when all costs are processed and costs are moved to the final asset.

Additional Information

For additional information regarding the use of Project and WBS elements, please refer to the Budget Guidelines.

PLANT IN SERVICE & RETIREMENT

4.1 Introduction

This chapter covers the policies related to custody, care, transfers, removal and or abandoning, and final disposal of capital assets within/from gas plant in service.

4.2 Capital Assets: Care, Custody and Control

Project/Asset Manager Responsible For

As part of their responsibility for the utilization, care and safekeeping of Terasen Gas capital assets under their control, managers shall ensure that:

- all transfers, removals from service are fully reported to them
- adequate internal controls are maintained
- all status change documents are forwarded to Asset Accounting

Asset Accounting Responsibility

Asset Accounting shall ensure that the accounting records correctly report additions, transfers, retirement, and changes of status, based on the information provided by the responsible managers.

General Ledger Capital Accounts

Accounts are setup on the Budget Guidelines Manual, Section 7, "Capital Budgets". Manuals to capture the current year's capital additions, retirements, related removal costs and salvage proceeds.

Subsidiary Plant Records

These accounts are called asset classes and are designed to classify the gas plant in service assets acquired or constructed and physically placed into service. These sub-accounts are primarily maintained by Asset Accounting and serve as subsidiary records to the GL100 and GL105 accounts. These asset classes can be found in the Budget Guidelines Manual, Section 7.3.3 Asset Class List.

PRU Catalogue

Asset Accounting maintains an inventory record of capital assets by Property Retirement Units (PRUs), as defined in the Property Retirement Unit Catalogue. The PRU Catalogue is an integral part of the Capitalization Policy. A PRU defines the lowest level of expenditure for capitalization and control.

Primary Sources

The primary sources of data for an accurate record of capital assets are, Fixed Asset Transfer (FAT) and Plant Retirement Requests (PRRs) documents. Each of these are discussed below.

4.3 Fixed Asset Transfers (FAT)

Change in Custody Only

Transfer of capital assets is confined to movements and changes in custody of one or more PRUs, which will continue to be used for the original or equivalent purpose.

Applies to

- General Plant or "portable type" PRUs when such units are physically transferred to another plant facility location in a different Capital District or Region
- Plant under construction (WIP), where existing PRUs are removed from one plant facility location and immediately re-installed, subject to cleaning or refurbishing, at a new project site under construction

Original Cost and Depreciation

The original cost, estimated if not known, of the PRU and, where applicable, the accumulated depreciation value is transferred. The accumulated depreciation applies where the transfer affects divisional boundaries.

Asset Transfer Document

The Asset Transfer form is prepared by the sending Cost Centre at the time the PRU is transferred, and must show the complete PRU description, make/type, serial number, year of acquisition, present and new locations, appropriate approvals and acknowledgement by the receiving cost centre.

4.4 Retirements

Service Value

The original cost or, where applicable, a reasonable estimate, is credited to the appropriate capital account with the offset entry to the accumulated depreciation account, for the PRU retired.

Items Less Than a PRU

- When plant, comprising less than a PRU, is removed and not replaced or improved upon in accordance with Section 2.3.2 "Improvements and Additions", no retirement entry will be made to the capital accounts at that time. Its value will be retired upon the retirement of the PRU with which it is associated.

- A retirement will be made where the PRU is rebuilt in excess of 50% of the replacement cost of a new plant unit of the same kind and class, see Section 2.3.3 “Rehabilitation/Major Renewals”

4.4.1 Specific Plant Retirement

Specific plant retirement occurs when:

Occurrences

- a complete PRU is physically removed or abandoned from plant in service
- an existing PRU is replaced
- improvements, substantial betterments, rehabilitations or major renewals are made to an existing PRUs concurrently with partial removal or abandonments to these PRUs. See Chapter 2, Sections 2.3.2 and 2.3.3

Documentation

- To maintain efficiency in processing documents on asset retirements/disposals, a separate form is used appropriate to the type of asset retirement. Refer to the Procedure Section of this manual.
- In the absence of specific retirement/disposal procedures, a Plant Retirement Request (PRR) is to be used.

4.4.2 Recurring Plant Retirement

Recurring plant retirement occurs when:

Occurrences

Mains (47500)	a main is removed or abandoned;
Services (47300)	a service line is deactivated to a stub service or, a complete service line is removed or abandoned;
Meter (47810)	a residential or commercial meter is removed from service

Quantity Reporting

No Plant Retirement (PRR) is required to retire Recurring Plant. In its place, annual plant unit reports for mains and services retired are generated by by running a Business Warehouse report in SAPFor meters retired monthly information is provided by the Measurement Group to Asset Accounting.

4.4.3 Retirement Accounting

By Asset Accounting

Asset Accounting Department makes all retirement accounting entries.

Unit Cost Tables

Retirement Unit Cost tables are computed annually for Recurring Plant, and used to establish retirement values based on quantity supplied by operations.

Original costs, estimate if not known, are used to retire Specific Plant PRUs.

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4.5 Removal Dismantling Costs

Associated With Retirements

Removal or dismantling costs are associated with asset retirements. It includes labour, material, contract services and other direct expenditures related to demolishing, dismantling, tearing down or otherwise removing PRUs from plant in service.

Refurbishing Costs

Costs incurred to refurbish "used" inventory or non-inventory materials recovered from gas plant in service is chargeable to the removal/dismantling project to which it relates; unless the refurbishment results in a rebuilt plant unit refer to Section 2.3.3 of this Manual.

Overhead

Overhead is NOT applied to removal/dismantling costs. Such costs are not considered significantly large in contrast to capital additions.

Negative Salvage Values

The provision for net negative salvage or removal costs are no longer included in deprecation but instead actual costs are estimated and included in cost of service and recovered from customers in each respective year. Any variances between the actual amount of net removal costs realized and the estimated amounts included in cost of service are recorded in a deferral account 'Removal Cost Deferral Account' by Asset Accounting.

4.6 Salvage/Proceeds Values

Credited to Work Order

Salvage or proceeds is the value of material recovered from capital retired and is credited to work orders.

Types of Salvage

Salvage value can be realized through:

- disposal by sale – salvage value is equal to the selling price
- recovery of large items to stock – reusable materials consisting of large individual items, usually a PRU, are salvaged at its original costs, estimated if not known
- recovery of small items to stock – reusable material consisting of relative small items, usually pipe fittings, is salvaged to stock at the prevailing inventory unit cost

Repair To Salvage Items

The cost incurred for repairing or refurbishing salvage items to its reusable condition, is part of the removal and dismantling process of asset retirement. When such repairs are done concurrent with the dismantling process, it can be charged to the appropriate dismantling/removal work order; otherwise, a new work order must be raised.

Insurance Claims

The value of insurance claim settlements received should be accounted for as follows:

- Property Retirement Unit (PRU) – as a salvage credit to the retirement of the PRU
- Non-Capital – the insurance proceeds will be credited to the account(s) chargeable with the expenditure necessary to restore the damaged plant

4.7 Gains and Losses on Disposal

Depreciable Assets

Gains or losses on asset disposal are transferred to a deferral account by asset accounting. Salvage proceeds realized whether through resale or recovery to inventory is credited to the accumulated depreciation reserve.

4.8 Inactive Plant

Classification

Assets retained but not longer considered actively engaged in gas utility operations are classified as Inactive Plant, and should either be:

- reclassified to gas plant held for future use
- disposed through resale
- removed/dismantled and scrapped

4.9 Fixed Assets Held For Resale

Initial Recording

Such assets are normally maintained in the capital account to which asset was initially recorded.

Intent To Dispose

If however, the intent to dispose of the asset by re-sale has been determined with no established date, and the asset is considered "inactive", then Asset Accounting may reclassify the asset to a separate capital sub-account, "Fixed Assets Held For Re-sale".

DEPRECIATION

5.1 Introduction

This Chapter covers the accounting policies concerning the computation of depreciation and the accounting treatment for special depreciable items of capital.

Matching Cost Concept

Capital expenditures are distributed as equitably as possible between present and future customers by matching these costs to the accounting period in which the associated benefits accrue. This is accomplished by the depreciation/amortization practices used by the Company.

5.2 Depreciation Versus Amortization

Allocation to Operating Expense

Both terms relate to allocating the cost of depreciable capital to operating expense except that:

- depreciation extends over the actual service life of the asset, where as
- amortization is limited to the contractual term of the asset

5.3 General Requirements

Basis of Depreciation

The basis is to allocate the cost of the depreciable asset, the salvage proceeds, over the estimated service life of an asset in a systematic and rational manner.

Commencement

Depreciation begins the month following when the asset is considered in-service.

Timing

Depreciation is provided on a straight-line basis, and computed in conformity with the "group system", i.e. a group of individual assets (PRUs) classified under the same capital account.

Method

Depreciation under the straight-line service-life method is computed by applying the annual percentage to the cost of depreciable capital as recorded in the capital account, divided by twelve for the monthly recording.

Rate

A separate rate for each asset class is used in computing depreciation.

Approval

The various rates are approved by regulatory authorities, e.g. BCUC.

The Service Life

The service life is the period of time between the installation or acquisition of the asset and its retirement for accounting purposes.

Depreciation Under Group System

The "group system" contemplates that some part of the investment in a group of assets will probably be recovered through salvage realizations, and that probably there will be variations in the service lives of assets constituting the group, even among assets of the same class. The depreciation provision determined for the group is a weighted average of the various individual provisions reflecting the individual expectancies of life and salvage for each PRU in the group.

Maintain Depreciation Records

It is not the intention of this group classification to require the Company to keep records of the accumulated depreciation of each PRU.

For the purposes of analysis, however, the Company shall maintain subsidiary records in which accumulated depreciation is sub-divided according to each group of Gas Plant Accounts.

5.4 Accounting For Special Depreciable Items

in rate base.

5.4.1 Contribution in Aid of Construction

Contribution credits in the G/L 21101 account are amortized over the average service lives of the capital assets to which they relate.

5.4.2 Leasehold Improvements

Leasehold improvements are amortized over the life of the lease (must be greater than 12 months), and retired from plant in service when occupancy is vacated.

5.4.3 Obsolete and Surplus Stock (Used)

The value of obsolete and/or surplus stock removed from inventory which can be identified as used items, shall be charged to accumulated depreciation as an adjustment to previous salvaged-credits realized.

5.5 Non-Depreciable Capital

Depreciation/amortization is not charged on:

- land and land rights
- work in progress
- inactive plant, unless by regulated agreement
- plant held for future use
- plant not in service

5.6 Disposal

When non-depreciable capital is disposed of through resale, the original cost of the asset is credited to the applicable capital account, and any substantial gain or loss is recorded as an extra ordinary item in the income statement. If this amount is not significant, it is reported as income or income deductions.

When depreciable capital is disposed of through resale the original cost of the asset is credited to the applicable capital account and charged to its corresponding accumulated depreciation account. The net salvage proceeds, if any is credited to the related accumulated depreciation account.

Attachment 6

Terasen Gas Inc.

Shared Services Cost Allocation Review

June 11, 2009

Table of Contents

1.0 Summary of Findings

Terasen Gas Inc. (TGI) retained KPMG to perform an independent review of its shared services cost allocation methodology and the reasonability of the costs of the shared services provided to Terasen Gas Vancouver Island Inc. (TGVI) and Terasen Gas Whistler Inc. (TGW) by TGI in preparation of its 2010/11 Revenue Rate Application (RRA).

In conducting this review KPMG verified that the services provided by TGI to TGVI and TGW are operationally necessary, the methodology used to allocate costs is reasonable, and the costs allocated are reasonable as compared to market alternatives.

KPMG assessed the reasonability of the methodology and the costs allocated to TGVI and TGW against the criteria in section 4.2 of this report. In completing the examination of the shared services cost allocation methodology and resulting costs, KPMG found the following:

Reasonability of the Organizational Structure

- TGI, TGVI and TGW operate under a shared management structure, where leadership resides in TGI;
- It is common in the utility industry to have affiliates provide services to each other for a number of reasons such as sharing overhead costs, sharing of specific expertise, and obtaining economies of scale; and
- KPMG finds this structure to be reasonable.

Necessity of the Services

- There are Service Level Agreements (SLAs) between each of the operating entities which are currently being updated. KPMG completed its review based on the existing 2004 SLAs but took into consideration pending changes in this review. KPMG did not have access to the completed 2009 SLAs prior to completing this review; however in discussions with management we understand that the impact of any changes will not be significant;
- KPMG confirmed that services provided by TGI to TGVI and TGW are not duplicated in TGVI and TGW or by any other source;
- All business, Distribution and Gas Supply and Transmission services as listed in the cost allocation model are commonly found in gas distribution companies;
- Distribution and Gas Supply and Transmission services are allocated in the shared services model. Inclusion of these services in a shared services model is a relatively unique arrangement resulting from the shared management structure and geographical proximity of TGI, TGVI and TGW; and
- KPMG finds that the shared services are all operationally necessary for TGVI and TGW.

Reasonability of the Methodology

- KPMG finds the cost allocation methodology to be reasonable, with the following exception:
    - While the British Columbia Utilities Commission (BCUC) has approved the use of customers as an allocation driver in TGI's 2004 cost allocation model (Order G-112-04), in certain cases we believe that using the number of customers as a driver to allocate costs is not the most related driver. In those cases, TGI should consider using an alternative driver, such as a financial composite driver as those services are more closely tied to the financial activity of TGI than the number of customers. A financial composite driver uses a combination of financial information to derive a percentage to allocate costs. KPMG reviewed two financial composite drivers including:
        - The Massachusetts Model: This model takes an average of revenue, payroll, and the net book value of capital assets and inventory to calculate the allocation percentage. This is a commonly used model in the North American utility industry. Applying the Massachusetts model to those services in question would result in a 2.5% increase ($1,543,462) in the allocation amount to TGVI and a 0.10% increase ($61,187) to TGW; and
        - A comparable Canadian utility financial composite: This model takes an average of revenue, total assets, and capital expenditures to calculate the allocation percentage. It is a variation of the Massachusetts Model that is common in the North American Utility industry. Applying this model to those services in question would result in a 2.19% increase ($1,354,397) in the allocation amount to TGVI and a 0.12% increase ($73,916) to TGW.

      Of the two financial composite drivers reviewed, the comparable Canadian utility financial composite driver is more suitable for TGI since it does not take into account payroll. Payroll would skew results as many employees that work on TGVI and TGW reside in TGI.
- KPMG notes that TGI has not documented its methodology approach outside of the model itself; formal written documentation would assist TGI in applying the methodology consistently year over year. KPMG suggests in the future that TGI consider formally documenting the methodology.

Reasonability of the Allocated Costs

- KPMG finds that it would not be more cost effective for TGVI and TGW to provide these shared services internally;
- KPMG did not evaluate the shared services in terms of having them provided by an external source; however KPMG notes that many of these shared services are not commonly outsourced as they are of strategic value to the business or are integral core businesses. These services would be impractical to outsource or valuable business insight may be lost (i.e. President & CEO, Distribution, Gas Supply and Transmission); and
- KPMG finds the costs allocated to TGVI and TGW from TGI to be reasonable with the following comment:

- KPMG compared TGI's rent costs to publicly available market information, and was not able to locate a comparable facility. However the research KPMG did conduct in the Greater Vancouver area indicates that TGI's rent overhead costs may be above market rates.
- Rent costs used in the model are driven by the underlying real estate value; there are a number of factors that influence the relatively higher value of the TGI facilities including the:
  - Relatively new age of the building;
  - Building fixtures and the extent to which the building is customized to meet TGI's uses;
  - Building location; and
  - Availability of parking on-site.
- The factors above result in the inherently higher value of TGI's facility when compared with available market information. TGI has obtained the opinion of a professional real estate broker who has validated the commercial rate of return used in TGI's calculation of rent costs.
- If TGI were to apply the average market rental rate determined in KPMG's limited research the effect would be approximately 2.6% less being allocated in the model resulting in $165,342 less to TGVI and $4,385 less to TGW.
- While KPMG has been able to narrow the gap between the costs in TGI's model and the available market information, KPMG believes further analysis would be required and an expert opinion received from a professional real estate evaluator. KPMG recommends that TGI continue to obtain regular appraisal of their facilities to validate both the value of the facility and the commercial rate of return used in the model. Documentation of such a review could be made available for evidence to support future inquiries and rate applications to ensure these values remain current.

Benefit to the Ratepayer

- Ratepayers benefit from TGI providing shared services to TGVI and TGW which results in economies of scale by having a single management and support structure, avoiding the duplication of work and allowing customers to benefit from the efficiencies realized. TGVI and TGW also benefit from the depth of expertise which is possible given the shared services structure. Ratepayers therefore benefit from enhanced efficiency.

2.0 Purpose of Report

TGI retained KPMG to perform an independent review of the shared services cost allocation methodology and the reasonability of the costs of the shared services provided to TGVI and TGW by TGI in preparation for the 2010/11 RRA.

KPMG conducted the review of the 2010/11 cost allocation model using 2009 budget figures as 2010/11 budget figures were not yet available. The budget has been reviewed and approved by Terasen Gas' Executive Leadership Team and is used as an input to the Earnings Sharing for the Annual Review with the BCUC.

2.1 Report Structure

The structure of this report is as follows:

Table 2.1a – Report Structure

Section	Description
1.0: Summary of Findings	Includes the summary of KPMG's findings.
2.0: Purpose of Report	Outlines the structure of the report and provides a brief explanation of each section.
3.0: Background	Provides an overview of the cost allocation methodology including the current organizational structure.
4.0: Approach and Methodology	Provides an explanation of KPMG's approach to reviewing TGI's shared services cost allocation methodology and resulting allocated costs including the assumptions and criteria against which KPMG performed its analysis.
5.0: KPMG Research	Provides a summary of the publicly available information KPMG used to perform its analysis of the 2010/11 allocation model and determine its findings.

2.2 Scope Limitations

KPMG’s assessment of the shared services cost allocation methodology and related costs involved relying on data and information provided to KPMG by TGI. The data provided by TGI was analyzed by KPMG in carrying out the assessment of the necessity of the services, the reasonability of the allocation methodology and the reasonability of the resulting costs. KPMG has considered the reasonableness of the information provided by TGI however KPMG did not conduct an audit. KPMG has assumed the completeness, accuracy and fair presentation of the information, data or advice provided by TGI. TGI maintains responsibility for the accuracy and completeness of the data and information associated with the shared services cost allocation methodology.

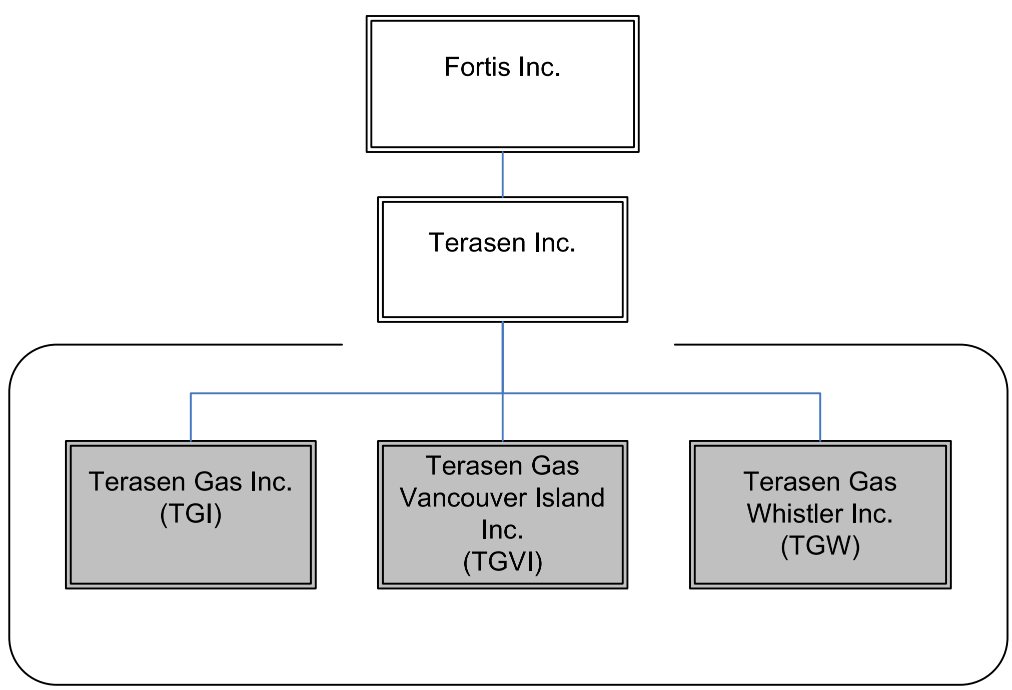
3.0 Background

TGI utilizes a cost allocation model to attribute a portion of its shared services operating costs to TGVI and TGW, both regulated affiliate utility companies.

3.1 Organizational Structure

While TI owns TGI, TGVI and TGW, TGI has operating responsibility for TGVI and TGW. The President & CEO and Vice President (VP) of TGI are also the President & CEO and VP's for TGVI and TGW. The following organization chart illustrates TGI's relationships to regulated and affiliate companies.

Figure 3.1 – Organization Chart



3.2 Shared Services

TGI provides shared services to TGVI and TGW that enable both companies to harness benefits from economies of scale by having a single management and support structure. The services that are provided are outlined in the respective service level agreements. The shared services to TGVI and TGW include services in the following business areas:

Table 3.2 – Shared Services Description

Department	Description
President & CEO's Office	• Overall governance and strategic direction • Overall communications with internal and external parties
Distribution	• Policy direction and oversight of services related to key operational areas • General management and oversight of services • Management of the daily gas distribution operations
HR & Operations Governance	• Human resource policy and management activities • Operational governance activities • Overseeing compliance with standards and regulation
Marketing	• Managing relations with customer groups and stakeholders • Managing customer accounts • Internal and external communications
Business & IT Services	• Managing IT applications and infrastructure • Facilities and Business Services management • Materials and Meter Management Services
Gas Supply & Transmission	• Managing programs relating to gas transmission operations • Developing and Maintaining a comprehensive Integrity Management Plan
Finance & Regulatory Affairs	• Accounting and reporting • Compliance and regulatory activities

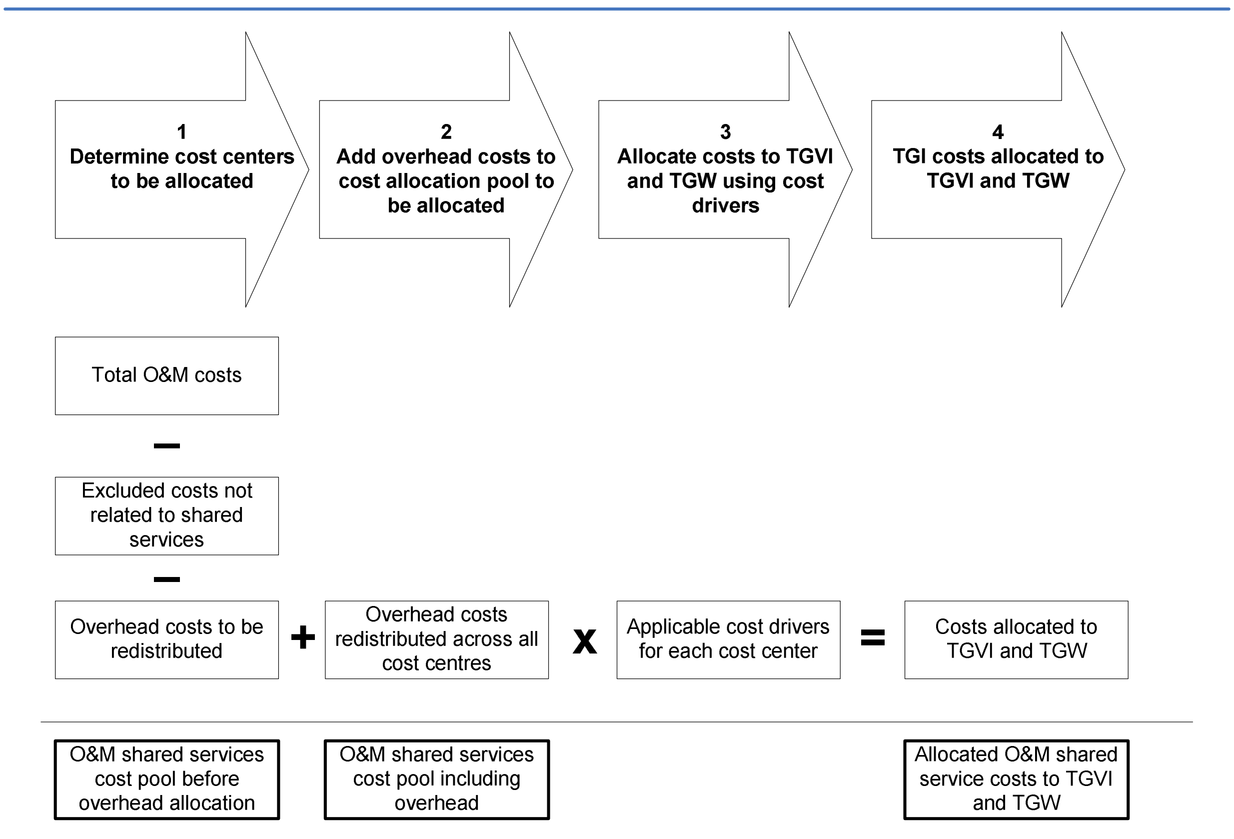
3.3 TGI Cost Allocation Model

Operations and maintenance (O&M) costs for shared services allocated from TGI to TGVI and TGW are calculated at the cost center level. Costs relating to shared services are accumulated into cost pools in each cost center. These costs also include an overhead costs which are distributed across all departments.

These cost pools are then allocated to TGVI and TGW using a specific cost driver. TGI and TGVI also receive a number of corporate shared services from TI. Costs for these services are allocated directly to TGI and TGVI using another shared services cost allocation model, and are not considered in this review.

The following provides a high level summary of how costs are allocated from TGI to TGVI and TGW.

Figure 3.3 – TGI Cost Allocation Model



The shared services cost allocation methodology and model are reviewed on an annual basis, typically in alignment with the budgeting process. Costs allocated are reviewed for budgeting purposes and trued up at year end.

3.4 TGI Costs

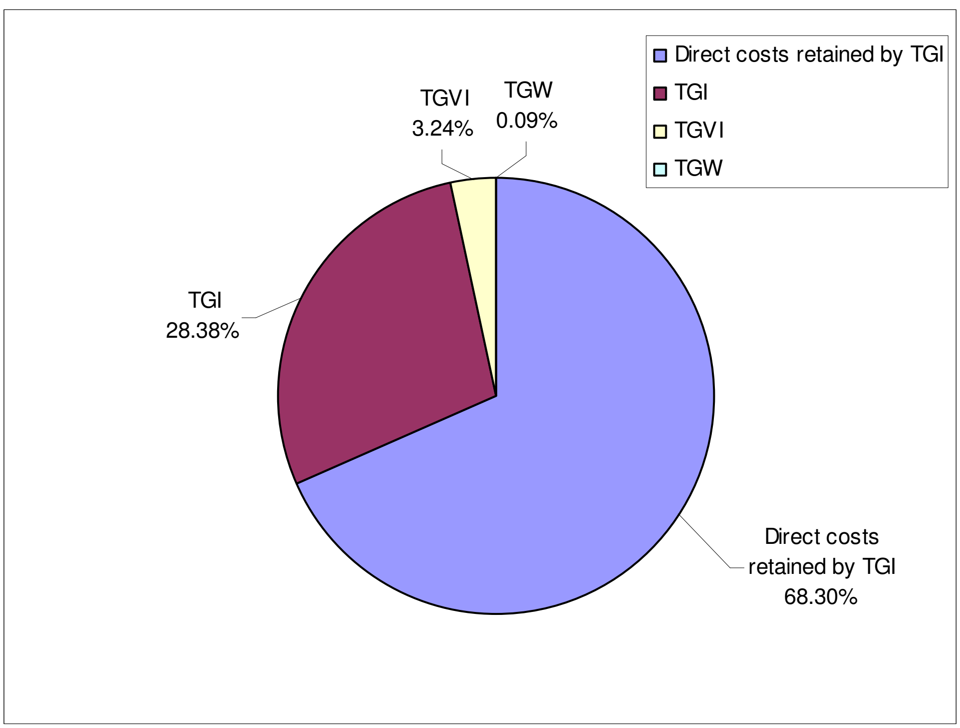
3.4.1 Overview

Budgeted costs allocated from TGI to TGVI and TGW include three components: labour, non-labour and overhead costs. The budget has been reviewed and approved by Terasen Gas' Executive Leadership Team and is used as an input to the Earnings Sharing for the Annual Review with the BCUC. The budgeted costs for 2010/11 will be reviewed as part of TGI's upcoming RRA.

A total of seven departments containing 126 cost centers make up the total shared services cost pool to be allocated between TGI, TGVI and TGW. The total cost pool for allocation is $61,561,380, of which $55,109,372, $6,283,451 and $168,557 are allocated to TGI, TGVI, and TGW respectively.

The following graphic shows the total operating costs for TGI and represents as a percentage those portions that are allocated as shared services to TGI, TGVI, and TGW.

Figure 3.4.1a – Percentage of TGI Costs Allocated



The following table details the FTEs associated with the costs allocated by service and shows the split between labour, non-labour and overhead cost components. The costs included in this table represent the pool of costs to be allocated to TGVI and TGW.

Table 3.4.1b – Labour and Non-labour Costs Allocated

Service	Company	% Allocated	Cost Allocated	FTE	Labour	Non-Labour	Overhead
President & CEO's Office	TGI	89.56%	$ 1,213,684	1.79	$ 626,486	$ 560,398	$ 26,800
	TGVI	10.18%	$ 137,891	0.20	$ 71,177	$ 63,669	$ 3,045
	TGW	0.26%	$ 3,575	0.01	$ 1,845	$ 1,651	$ 79
	Total	100.00%	$ 1,355,150	2.00	$ 699,509	$ 625,717	$ 29,924
Distribution	TGI	84.75%	$ 8,758,409	96.73	$ 6,957,502	$ 465,785	$ 1,335,122
	TGVI	14.87%	$ 1,536,722	18.54	$ 1,218,763	$ 65,213	$ 252,746
	TGW	0.39%	$ 39,838	0.48	$ 31,595	$ 1,691	$ 6,552
	Total	100.00%	$ 10,334,969	115.75	$ 8,207,860	$ 532,688	$ 1,594,421
HR & Operations Governance	TGI	91.71%	$ 8,692,805	71.78	$ 6,004,576	$ 1,645,671	$ 1,042,558
	TGVI	8.09%	$ 766,503	6.41	$ 521,392	$ 152,048	$ 93,063
	TGW	0.20%	$ 18,886	0.16	$ 12,762	$ 3,778	$ 2,346
	Total	100.00%	$ 9,478,195	78.35	$ 6,538,730	$ 1,801,497	$ 1,137,968
Marketing	TGI	89.48%	$ 7,531,589	62.55	$ 5,514,699	$ 1,124,212	$ 892,678
	TGVI	10.16%	$ 855,086	7.10	$ 626,037	$ 127,698	$ 101,351
	TGW	0.36%	$ 30,364	0.23	$ 22,279	$ 4,710	$ 3,375
	Total	100.00%	$ 8,417,041	69.88	$ 6,163,016	$ 1,256,621	$ 997,404
Business & IT Services	TGI	90.80%	$ 20,063,640	177.75	$13,544,391	$ 4,053,756	$ 2,465,493
	TGVI	8.97%	$ 1,981,853	20.23	$ 1,337,041	$ 364,525	$ 280,287
	TGW	0.23%	$ 49,830	0.52	$ 33,693	$ 9,000	$ 7,137
	Total	100.00%	$ 22,095,321	198.50	$14,915,124	$ 4,427,280	$ 2,752,917
Gas Supply & Transmission	TGI	89.56%	$ 1,477,591	16.12	$ 1,047,392	$ 204,605	$ 225,594
	TGVI	10.18%	$ 167,875	1.83	$ 118,998	$ 23,246	$ 25,631
	TGW	0.26%	$ 4,352	0.05	$ 3,085	$ 603	$ 664
	Total	100.00%	$ 1,649,817	18.00	$ 1,169,475	$ 228,453	$ 251,889
Finance & Regulatory Affairs	TGI	89.56%	$ 7,371,654	57.32	$ 6,016,191	$ 546,809	$ 808,654
	TGVI	10.18%	$ 837,521	6.51	$ 683,522	$ 62,125	$ 91,874
	TGW	0.26%	$ 21,712	0.17	$ 17,719	$ 1,611	$ 2,382
	Total	100.00%	$ 8,230,887	64.00	$ 6,717,432	$ 610,545	$ 902,910

3.4.2 Labour Costs

The labour costs include the following types of Full Time Equivalents (FTE):

- Management & Exempt (M&E) employees
- Canadian Office and Professional Employees (COPE) Union Local 378 employees
- International Brotherhood of Electrical Workers (IBEW) Union Local 213 employees

The labour costs include the following cost components:

- Base salary
- Bonus
- Employee benefits

3.4.3 Non-Labour Costs

The non-labour costs include the following key components:

- Travel
- Employee expenses
- Company vehicles
- Supplies
- Membership fees (excluding WEI/CGA membership fees included in overhead costs)
- Employee training
- Consulting services
- Legal services
- IT support services
- Administration

3.4.4 Overhead Costs

Overhead costs are allocated to TGVI and TGW for shared services provided by TGI. Overhead costs include the following components:

- Rent
- IT Services (ITS)
- Membership Fees
- Medium Term Compensation
- Other Post Employment Benefits (OPEB)

An overhead rate per FTE is calculated and applied to each relevant FTE in each cost center. These costs become a part of the cost pool along with labour and non-labour costs that are allocated to TGVI and TGW.

3.5 Cost Drivers

Once labour, non-labour and overhead costs are accumulated in the cost pools of each cost center, the amounts are then allocated from TGI to TGVI and TGW using a cost driver. The driver TGI uses to allocate costs depends on the type of service being provided. Management determines the most relevant cost driver for each cost center based on the key driver of cost.

The following cost drivers are used to allocate overhead costs to individual cost centers:

Table 3.5a – Overhead Cost Drivers

Drivers	Rent	IT Services	Membership Fees *	Medium Term Compensation	OPEB
Employees	X	X	X		X
M&E Employee			X	X	

** Different membership fees use different drivers*

One cost driver is selected for each cost center; therefore multiple drivers may be used in each department.

The following cost drivers are used within each department to allocate costs:

Table 3.5b – Cost Drivers

Drivers	President & CEO	Distribution	Human Resources & Operations Governance	Marketing	Business & Information Technology Services	Gas Supply & Transmission	Finance & Regulatory Affairs
Customers	X	X	X	X	X	X	X
Employees			X		X		
Management Estimate of Time		X	X	X	X		

3.5.1 Customer Driver

The customer cost driver allocates costs based on the percentage of customers receiving service from TGI, TGVI and TGW.

3.5.2 Employee Driver

The employee cost driver allocates costs based on the number of FTEs in TGI, TGVI and TGW respectively.

3.5.3 Management Estimate of Time

Some costs are allocated using management's estimate of time as a driver. Management followed a consistent methodology to estimate the percentage of time spent on providing shared services (i.e. if all employee time in a specific cost centre is spent on TGVI and TGW activities, management will allocate the cost to only TGVI and TGW). The cost allocated by management estimate of time is then added to the cost center cost pool and subsequently allocated to TGVI and TGW using the relevant driver for that cost center.

4.0 Approach and Methodology

4.1 Approach

KPMG's approach to reviewing TGI's shared services cost allocation methodology involved assessing the necessity of the services provided, the reasonability of the allocation methodology, the reasonability of the costs allocated to TGVI and TGW, and the benefit to rate payers of those affiliates.

KPMG's assessment is founded on a detailed understanding and analysis of the work performed by TGI and the services received by TGVI and TGW. KPMG's review of TGI's cost allocation methodology involved the following:

- Holding discussions with TGI finance management and staff;
- Reviewing policies, procedures and other relevant organizational documentation (such as SLAs, organizational charts, compensation and procurement policies, Codes of Conduct, COPE union agreement);
- Reviewing historical regulatory submissions and cost allocation models;
- Reviewing the cost allocation model;
- Validating the accuracy of the data in the model against internal financial management reports (generated from SAP);
- Conducting market research;
- Conducting analysis; and
- Producing this report containing our findings.

To perform the analysis KPMG consulted publicly available information as set out in section 5.0 of this report.

4.2 Methodology and Criteria

KPMG acknowledges the interest that regulators of utilities in Canada have shown in cost allocation methodologies and the resulting costs to ensure they are reasonable. KPMG applies a set of criteria to assess each service that is reflective of the examination regulators have used to make informed decisions. The review criteria are described in the following groups: Services, Allocation Methodology, Costs, and Benefits.

Services

In assessing the reasonableness of services provided by TGI to TGVI and TGW, KPMG applied the following criteria:

Table 4.2a – Services Review Criteria

Review Criteria	Description
Operationally Necessary	Confirm that the service is necessary to operate a gas utility distribution business.
Redundancy	Confirm that the services provided to the receiving entity are not already provided internally by that entity or provided to that entity by another party.
Services Level Agreement (SLA)	Confirm that a SLA exists for the services provided by TGI to the receiving entity.

Allocation Methodology

In assessing the reasonableness of the allocation methodology for attributing the costs from TGI to TGVI and TGW, KPMG applied the following criteria:

Table 4.2b – Allocation Methodology Review Criteria

Review Criteria	Description
Regulatory Precedence	The cost allocation methodology has been tested and approved (i.e. an acceptance of reasonability has been previously established) through regulatory reviews of TGI or other regulated utilities.
Reflective of Service or Investment	The allocation methodology is reflective of the work required to perform the service for TGVI/TGW or reflective of the investment value in TGVI/TGW (i.e. time, assets, and revenue).
Supportable Methodology	The allocation approach is supported by a defined and documented methodology, model, and other supporting documentation. The allocation driver is also linked to an SLA that is updated and reviewed on a consistent basis.
Cost Effective	The allocation driver is calculated and maintained from readily available information resulting in minimal time and expense.
Stable Over Time	The allocation methodology can accommodate changes to the size of the allocation driver from test period to test period and is scaleable given changes in the amount of cost and types of services being allocated.
Objective Results	The use of the allocation driver results in an objective allocation amount that is reasonable for a company of that size for the services being rendered.

Costs

In assessing the reasonableness of the forecast costs for the services provided by TGI to TGVI and TGW, KPMG applied the following criteria:

Table 4.2c – Cost Review Criteria

Review Criteria	Description
Supportable Cost	Independent research conducted supports the reasonableness of the cost for the services provided.
Internal Provision of Service Alternative	Independent research conducted confirms that internal TGVI/TGW provision of the service would not result in a lower cost.
Outsourcing / Third Party Alternative	Independent research conducted confirms that an outsourcing or third party alternative to provide the service would not result in a more reasonable cost.

Benefits

In assessing the reasonableness of the allocation KPMG also considered if there are benefits that arise from having shared services provided by TGI to TGVI and TGW.

5.0 KPMG Research

To determine the reasonability of the shared services provided by TGI to TGVI and TGW as budgeted in 2009, KPMG gathered publicly available information from which to perform its comparative analysis. KPMG found this body of research to be sufficient in determining and supporting the reasonability of the allocation methodology and the resulting costs.

KPMG's research focused on the nature of the shared services, the cost allocation methodology, and the costs of these services.

5.1 Service Research

KPMG assessed the reasonableness of the nature of shared services provided by TGI by comparing them to other similar gas utility companies and KPMG's knowledge of the utility industry.

5.2 Cost Allocation Methodology Research

KPMG's assessment involved comparing the shared services cost allocation methodology used by TGI to methodologies used by other similar utility companies. KPMG also reviewed relevant regulatory applications and decisions for precedence which could be used to assess TGI's shared services cost allocation methodology. This assessment also involved assessing the cost drivers used in the methodology.

5.3 Cost Research

KPMG's detailed review of the costs allocated in the model included:

- **Labour costs** – KPMG assessed the reasonableness of labour costs for Management and Exempt (M&E) employees against TGI's internal compensation policy, salary bands and market rates for similar positions. KPMG conducted a more detailed review of executive labour costs by individual against market rates for reasonableness. KPMG did not review the labour costs related to union positions in detail as these agreements are negotiated and hence are assumed to represent market rates.
- **Non-labour costs** – KPMG assessed the reasonableness of non-labour costs at a high level by reviewing the nature and amount of costs given the size of the cost center, the scope of services, KPMG's knowledge of the utility industry, and comparable market information.
- **Overhead costs** – KPMG assessed the reasonableness of overhead costs at a high level by reviewing the nature and amount of overhead costs given the size of the company, KPMG's knowledge of the utility industry, and comparable market information.

5.4 Summary of Public Information Reviewed

The following list highlights the key research components and how KPMG used it to determine its findings:

Table 5.4 – Research Sources

Source	Description
• System for Electronic Documentation and Analysis Retrieval (SEDAR) Company Profiles • Confidential Sources	President & CEO and executives' compensation for similar sized public companies as TGI.
• Monster 2009 Salary Center • Payscale Salary Survey Reports April 2009 • Hays 2009 Salary Guides • KPMG internal knowledge from client contacts and experience	Compensation information for positions similar to those of TGVI/TGW and for the allocated services provided by TGI; used for compensation comparisons and findings related to internal service provision by TGI.
• Honda Canada • Toyota Canada • VW Canada	Car lease rates for monthly vehicle expenses.
• Commercial Listing Service (CLS) Link Real Estate Board of Greater Vancouver • The Canadian Real Estate Association (CREA)	Market rental rates for office space
• Being the Best: Insights from Leading Finance Functions • KPMG internal knowledge from client contacts and experience	Trends towards outsourcing corporate shared services functions and the cost of outsourcing services.
• Independent Evaluation of Enbridge Gas Distribution Inc.'s Regulatory Corporate Cost Allocation Methodology, Meyers Norris Penny, 2005 • BC Hydro, Revenue Requirements Application, 2004/05, 2007/08, and 2009/10 • Pacific Northern Gas, Revenue Requirements Application to the BC Utilities Commissions – 2008 and 2009 • EPCOR, Corporate Services Review, Bearing Point, 2005 • Union Gas, Cost Allocation Methodology Review, Price Waterhouse Cooper, 2005 • Union Gas, EB-2005-0520 - 2007 Rates • AltaGas Utilities Inc, 2008/09 Cost Allocation Review, KPMG, 2008	Regulatory filings and decisions to determine regulatory precedence regarding allocation drivers and compensation-related approvals.

5.5 Summary of TGI Information Reviewed

The following list highlights the key TGI information sources and how KPMG used it to determine its findings:

Table 5.5 – TGI Information Sources

Source	Description
• TGI Code of Conduct • TGI Code of Business Conduct	Codes of conduct governing relations and activity of TGI.
• Internal testing of the 2009 TGI to TGVI and TGW cost allocation model	Testing performed by TGI finance management of the 2009 cost allocation model.
• Terasen Gas Compensation Overview	Overview of TGI's compensation packages for M&E, COPE and IBEW employees
• TGI Procurement Policy	TGI's policy for acquisition of materials, equipment, and services.
• COPE Union Local 378 Collective Agreement	Collective agreement between COPE Local 378 employees and TGI.

Attachment 7a

FORTISBC ENERGY INC. (FORMERLY TERASEN GAS INC.)

An indirect subsidiary of Fortis Inc.

Consolidated Financial Statements
For the years ended December 31, 2011 and 2010

MANAGEMENT'S REPORT

The accompanying annual consolidated financial statements of FortisBC Energy Inc. have been prepared by management, who are responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These annual consolidated financial statements were prepared in accordance with accounting principles generally accepted in Canada. In meeting its responsibility for the reliability and integrity of the annual consolidated financial statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation focus on the need for training of qualified and professional employees and the effective communication of management guidelines and policies. The effectiveness of the internal controls of FortisBC Energy Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit and Risk Committee (Audit Committee) which is composed of four independent directors and one director who is an officer of a related company. The Audit Committee oversees the external audit of the Corporation's annual consolidated financial statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the external audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's annual consolidated financial statements are reviewed by the Audit Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit Committee. The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's annual consolidated financial statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes.

The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review shareholders' auditors' independence and auditors' fees.

The 2011 annual consolidated financial statements and Management's Discussion and Analysis were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of FortisBC Energy Inc.

Ernst & Young, LLP, independent auditors appointed by the shareholders of FortisBC Energy Inc. upon recommendation of the Audit Committee, have performed an audit of the 2011 annual consolidated financial statements and their report follows.

(Signed by)

John Walker
President and Chief Executive Officer

(Signed by)

Michele Leeners
Vice President, Finance and Chief Financial Officer

Vancouver, Canada
February 7, 2012

INDEPENDENT AUDITORS' REPORT

To the Shareholders of
FortisBC Energy Inc.

We have audited the accompanying consolidated financial statements of **FortisBC Energy Inc.** (formerly Terasen Gas Inc.), which comprise the consolidated balance sheets as at December 31, 2011 and 2010, and the consolidated statements of earnings and comprehensive earnings, retained earnings and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of **FortisBC Energy Inc.** (formerly Terasen Gas Inc.) as at December 31, 2011 and 2010 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Vancouver, Canada,
February 7, 2012.

Chartered Accountants

FORTIS BC

FortisBC Energy Inc.
Consolidated Balance Sheets
As at December 31
(in millions of Canadian dollars)

	2011	2010
ASSETS		
Current assets		
Cash and cash equivalents	**$ 17.2**	$ 15.2
Accounts receivable, net	**238.4**	298.1
Inventories of gas in storage and supplies (note 2)	**101.3**	136.3
Prepaid expenses	**3.1**	2.7
Future income taxes (note 13)	**10.1**	8.6
Current portion of rate stabilization accounts (note 5)	**68.5**	96.3
	438.6	557.2
Property, plant and equipment, net (note 3)	**2,513.1**	2,466.1
Intangible assets, net (note 4)	**116.6**	94.9
Other assets (note 6)	**434.6**	365.7
	$ 3,502.9	$ 3,483.9
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term notes (note 14)	**$ 65.0**	$ 178.0
Accounts payable and accrued liabilities	**303.7**	357.9
Income and other taxes payable	**39.4**	36.0
Current portion of rate stabilization accounts (note 5)	**18.7**	3.6
Future income taxes (note 13)	**-**	1.3
Current portion of long-term debt (note 7)	**2.9**	2.6
Other current liabilities and deferred credits (note 8)	**-**	11.7
	429.7	591.1
Long-term debt (note 7)	**1,542.5**	1,442.1
Rate stabilization accounts (note 5)	**22.4**	7.1
Other long-term liabilities and deferred credits (note 8)	**155.0**	141.5
Future income taxes (note 13)	**303.8**	279.6
	2,453.4	2,461.4
Shareholders' equity		
Share capital (note 9)	**719.0**	719.0
Contributed surplus (note 9)	**266.2**	256.1
Retained earnings	**64.3**	47.4
	1,049.5	1,022.5
	$ 3,502.9	$ 3,483.9

Approved on Behalf of the Board:

(Signed by) Harold Calla
Director

(Signed by) John Walker
Director

The accompanying notes are an integral part of these Consolidated Financial Statements.

FortisBC Energy Inc.
Consolidated Statements of Earnings and Comprehensive Earnings
For the years ended December 31
(in millions of Canadian dollars)

	2011	2010
Revenues		
Natural gas transmission and distribution	**$ 1,354.8**	$ 1,362.1
Expenses		
Cost of natural gas	**763.3**	790.0
Operation and maintenance (note 15)	**218.6**	206.2
Depreciation and amortization	**81.2**	82.9
Amortization of intangible assets	**8.1**	8.2
Property and other taxes	**50.4**	49.3
	1,121.6	1,136.6
Operating income	**233.2**	225.5
Financing costs (note 11)	**104.3**	102.5
Earnings before income taxes	**128.9**	123.0
Income tax expense (note 13)	**27.0**	29.8
Net earnings and comprehensive earnings	**$ 101.9**	$ 93.2

The accompanying notes are an integral part of these Consolidated Financial Statements.

FortisBC Energy Inc.
Consolidated Statements of Retained Earnings
For the years ended December 31
(in millions of Canadian dollars)

	2011	2010
Retained earnings, beginning of year	**$ 47.4**	$ 38.2
Net earnings	**101.9**	93.2
	149.3	131.4
Dividends on common shares	**(85.0)**	(84.0)
Retained earnings, end of year	**$ 64.3**	$ 47.4

The accompanying notes are an integral part of these Consolidated Financial Statements.

FortisBC Energy Inc.
Consolidated Statements of Cash Flows
For the years ended December 31
(in millions of Canadian dollars)

	2011	2010
Cash flows provided by (used for)		
Operating activities		
Net earnings	**$ 101.9**	$ 93.2
Adjustments for non-cash items		
Depreciation and amortization	**89.3**	91.1
Other	**(0.6)**	(7.3)
	190.6	177.0
Changes in non-cash working capital	**94.9**	(14.7)
	285.5	162.3
Investing activities		
Property, plant and equipment	**(139.1)**	(136.5)
Intangible assets	**(29.9)**	(20.5)
Other assets	**(17.1)**	(13.4)
	(186.1)	(170.4)
Financing activities		
Decrease in short-term notes	**(113.0)**	(26.0)
Issuance of long-term debt	**100.6**	2.2
Issuance of common shares	**-**	125.0
Dividends on common shares	**(85.0)**	(84.0)
	(97.4)	17.2
Net increase in cash and cash equivalents	**2.0**	9.1
Cash and cash equivalents at beginning of year	**15.2**	6.1
Cash and cash equivalents at end of year	**$ 17.2**	$ 15.2

Supplementary Information to Consolidated Statements of Cash Flows (note 12)
The accompanying notes are an integral part of these Consolidated Financial Statements.

1. SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

The preparation of these consolidated financial statements in conformity with Canadian generally accepted accounting principles (Canadian GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses in the consolidated financial statements, as well as the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

As a qualifying entity with rate-regulated activities, the Corporation elected to opt for the one-year deferral and, therefore, continued to prepare its consolidated financial statements in accordance with Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook for all interim and annual periods ending on or before December 31, 2011.

Certain comparative figures have been reclassified to conform to the current year's presentation.

REGULATION

The Corporation is subject to the regulation of the British Columbia Utilities Commission (the BCUC), an independent regulatory authority. The BCUC exercises statutory authority over such matters as rates of return, construction and operation of facilities, accounting practices, rates, and contractual agreements with customers. Rates are bundled to include transmission and distribution services, where applicable.

In 2009, the Corporation reached a negotiated settlement agreement (2010/2011 NSA) that was a cost-of-service based agreement and covered the 2010 and 2011 time periods. FortisBC Energy Inc. (FEI) earns an allowed rate of return that is based on a deemed debt-equity ratio of 60.00 per cent debt and 40.00 per cent equity. During 2009, FEI applied to the BCUC for and received an increase in the common equity component in capital structure allowed for rate-making purposes to 40.00 per cent from 35.01 per cent effective January 1, 2010. During 2009, the Corporation applied to the BCUC for an increase to the ROE and to discontinue the use of the automatic adjustment mechanism previously used. Late in 2009, the BCUC directed the ROE to be set at 9.50 per cent for FEI effective July 1, 2009 and directed the Corporation to discontinue the use of the automatic adjustment mechanism previously used.

In order to recognize the economic effects of regulation, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under Canadian GAAP for non-regulated businesses.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in other assets whereas rate stabilization accounts are recorded as current portion of rate stabilization accounts. Long-term regulatory liabilities are recorded in other long-term liabilities and deferred credits, whereas rate stabilization accounts are recorded as current and long-term rate stabilization accounts.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

REGULATION (CONTINUED)

The impacts of rate regulation on the Corporation's operations for the years ending December 31, 2011 and 2010 and as at December 31, 2011 and 2010 are described in these Significant Accounting Policies, and in note 3 "Property, Plant and Equipment", note 5 "Rate Stabilization Accounts", note 6 "Other Assets", note 8 "Other Long-Term Liabilities and Deferred Credits", note 10 "Employee Benefit Plans", note 11 "Financing Costs", and note 13 "Income Taxes".

RATE STABILIZATION ACCOUNTS

The Corporation is authorized by the BCUC to maintain rate stabilization accounts that mitigate the effect on its earnings of certain unpredictable and uncontrollable factors, such as volume volatility caused principally by weather and natural gas cost volatility. The Revenue Stabilization Adjustment Mechanism (RSAM) accumulates the margin impact of variations in the actual versus forecast volume use for residential and commercial customers.

The Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA) accumulate differences between actual natural gas costs and forecast natural gas costs as recovered in rates. The two accounts segregate costs that are allocable to all sales customers (MCRA) and all residential customers and certain commercial and industrial customers for whom FEI acquires gas supply (CCRA).

All rate stabilization account balances are amortized and recovered through rates as approved by the BCUC.

CASH and CASH EQUIVALENTS

Cash and cash equivalents include cash and short-term deposits with maturities of three months or less from the date of acquisition.

INVENTORIES

Inventories of gas in storage are valued at weighted-average cost. The cost of gas in storage is recovered from customers in future rates.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are recorded at cost less accumulated depreciation and unamortized contributions in aid of construction. Cost includes all direct expenditures for system expansions, betterments and replacements, an allocation of overhead costs as prescribed by the regulator and an allowance for funds used during construction as prescribed by the regulator. When allowed by the BCUC, regulated operations capitalize an allowance for equity funds used during construction at approved rates.

Depreciation of regulated assets is recorded on a straight-line basis over their useful lives. Depreciation rates for regulated assets are approved by the respective regulator.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

PROPERTY, PLANT AND EQUIPMENT (CONTINUED)

Effective January 1, 2010 as approved in the 2010/2011 NSA, asset removal costs are recorded in operating and maintenance expense on the consolidated statement of earnings and comprehensive earnings and gains and losses on the sale or removal of utility capital assets are recorded in a regulatory deferral account on the consolidated balance sheet for recovery from, or refund to, customers in future rates, subject to regulatory approval.

INTANGIBLE ASSETS

Intangible assets are recorded at cost less accumulated depreciation and unamortized contributions in aid of construction. Cost includes all direct expenditures, betterments and replacements, an allocation of overhead costs and an allowance for funds used during construction. When allowed by the regulators, regulated operations capitalize an allowance for equity funds used during construction at approved rates.

The useful lives of intangible assets are assessed to be either finite or indefinite. Intangible assets with finite lives are amortized over their useful life and assessed for impairment whenever there is an indication that the intangible asset may be impaired. Amortization rates for regulated intangible assets are approved by the respective regulators, and for non-regulated intangible assets require the use of management estimates of the useful lives of assets.

Intangible assets are derecognized on disposal, or when no future economic benefits are expected from their use. Effective January 1, 2010 as approved in the 2010/2011 NSA, asset removal costs are recorded in operating and maintenance expense on the consolidated statement of earnings and comprehensive earnings and gains and losses on the sale or removal of utility intangible assets are recorded in a regulatory deferral account on the consolidated balance sheet for recovery from, or refund to, customers in future rates, subject to regulatory approval.

Intangible assets with indefinite useful lives are tested for impairment annually either individually or where there are indicators that two or more indefinite useful life intangible assets should be combined, then as a single unit of accounting. Such intangibles are not amortized. The useful life of an intangible asset with an indefinite useful life is reviewed annually to determine whether the indefinite life assessment continues to be supportable. If not, the change in the useful life assessment from indefinite to finite is made on a prospective basis.

IMPAIRMENT OF LONG-LIVED ASSETS

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset and eventual disposition. If the carrying amount of an asset exceeds its estimated future cash flows and eventual disposition, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset. There was no impairment of long-lived assets for the years ended December 31, 2011 and 2010.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

DEFERRED CHARGES

The Corporation defers certain costs that the regulatory authorities or contractual arrangements require or permit to be recovered through future rates. Deferred charges are amortized over various periods as approved by the BCUC and depending on the nature of the costs.

Deferred charges not subject to regulation relate to projects that will benefit future periods and will be capitalized on completion, expensed on project abandonment, or amortized over their useful lives.

ASSET RETIREMENT OBLIGATIONS

The Corporation will recognize the fair value of a future asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that results from the acquisition, construction, development, and/or normal use of the assets. The Corporation will concurrently recognize a corresponding increase in the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset. The fair value of the asset retirement obligation is to be estimated using the expected cash flow approach that reflects a range of possible outcomes discounted at a credit-adjusted risk-free interest rate. Subsequent to the initial measurement, the asset retirement obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

Changes in the obligation due to the passage of time are to be recognized in income as an operating expense using the interest method. Changes in the obligation due to changes in estimated cash flows are to be recognized as an adjustment of the carrying amount of the related long-lived asset that is depreciated over the remaining life of the asset.

As the fair value of future removal and site restoration costs for the Corporation's natural gas transmission and distribution systems are not currently determinable as they will be used in perpetuity, the Corporation has not recognized an asset retirement obligation at December 31, 2011 and 2010. For regulated operations there is a reasonable expectation that asset retirement costs would be recoverable through future rates.

REVENUE RECOGNITION

The Corporation recognizes revenues when products have been delivered or services have been performed.

Revenues from natural gas sales are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year and are adjusted for the RSAM and other BCUC approved orders.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

POST-EMPLOYMENT BENEFIT PLANS

The Corporation sponsors a number of employee benefit plans. These plans include both defined benefit and defined contribution pension plans, and various other post-retirement benefit plans.

The cost of pensions and other post-retirement benefits earned by employees are actuarially determined as the employee provides service. The Corporation uses the projected benefit prorate method based on years of service, management's best estimates of expected returns on plan assets, salary escalation, retirement age of employees, mortality and expected future health-care costs. The discount rate used to value liabilities is based on AA Corporate bond yields. The Corporation accrues the cost of defined benefit pensions and post-employment benefits as the employee provides services. The Corporation uses a measurement date of December 31 for all plans.

The expected return on plan assets is based on management's estimate of the long-term expected rate of return on plan assets and a market-related value of plan assets. The market-related value of assets is determined using a smoothed value that recognizes investment gains and losses gradually over a three-year period.

Adjustments, in excess of 10 per cent of the greater of the accrued benefit obligation and plan asset fair value, that result from plan amendments, changes in assumptions and experience gains and losses, are amortized over the expected average remaining service life of the employee group covered by the plan. Experience will often deviate from the actuarial assumptions resulting in actuarial gains and losses.

Defined contribution plan costs are expensed by the Corporation as contributions are payable.

FINANCIAL INSTRUMENTS

a) Section 3855, *Financial Instruments – Recognition and Measurement*, prescribes the criteria for recognition and presentation of financial instruments on the balance sheet and the measurement of financial instruments according to prescribed classifications. This section also addresses how financial instruments are measured subsequent to initial recognition and how the gains and losses are recognized.

   The Corporation is required to designate its financial instruments into one of the following five categories: held for trading; available for sale; held to maturity; loans and receivables; and other financial liabilities. All financial instruments are to be initially measured at fair value. Financial instruments classified as held for trading or available for sale are subsequently measured at fair value with any change in fair value recorded in net earnings and other comprehensive income, respectively. All other financial instruments are subsequently measured at amortized cost.

   All derivative financial instruments are recorded on the balance sheet at fair value. The Corporation utilizes derivatives only to manage its exposure to changes in foreign currency exchange and energy commodity prices in its rate-regulated operations. The Corporation does not enter into derivative contracts for speculative purposes.

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

FINANCIAL INSTRUMENTS (CONTINUED)

Mark-to-market adjustments on these instruments is subject to regulatory deferral treatment to be recovered from or refunded to customers in future rates. In non-regulated entities the mark-to-market adjustment would either be recorded to earnings or other comprehensive income or a combination of both depending on whether hedge accounting is applied, the nature of the hedging relationship and whether there is ineffectiveness in the hedging relationship.

In accordance with the standard's transitional provisions, the Corporation recognizes as separate assets and liabilities only embedded derivatives acquired or substantively modified on or after January 1, 2003.

The Corporation has designated its financial instruments as follows:

- Cash and cash equivalents are classified as "*Held for Trading*" and are recorded at fair value. Due to the relatively short period to maturity of these financial instruments the carrying values approximate their fair values.
- Accounts receivable and long-term receivables are classified as *"Loans and Receivables."* These financial assets are recorded at values that approximate their amortized cost using the effective interest method.
- Short-term notes, accounts payable and accrued liabilities, long-term debt, and related issue costs are classified as "*Other Financial Liabilities.*" These financial liabilities are recorded at values that approximate their amortized cost using the effective interest method.
- Natural gas contracts are classified as "*Held for Trading*" and are recorded at fair value.

The Corporation recognizes transaction costs associated with financial assets and liabilities, that are classified as other than held for trading, as an adjustment to the cost of those financial assets and liabilities recorded on the balance sheet. These transaction costs are amortized into earnings using the effective interest rate method over the life of the related financial instrument.

b) Section 3862, *Financial Instruments – Disclosures*, establishes a hierarchal disclosure framework associated with the level of pricing observability utilized in measuring fair value. This framework defines three levels of inputs to the fair value measurement process, and requires that each fair value measurement be assigned to a level corresponding to the lowest level input that is significant to the fair value measurement in its entirety. The three broad levels of inputs defined by the Section 3862 hierarchy are as follows:

I. Level 1 Inputs - quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date;

II. Level 2 Inputs - inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices); and

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

FINANCIAL INSTRUMENTS (CONTINUED)

III. Level 3 Inputs - inputs for the asset or liability that are not based on observable market data (unobservable inputs). These unobservable inputs reflect the entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability, and are developed based on the best information available in the circumstances (which might include the reporting entity's own data).

The disclosures required by the hierarchal disclosure framework are disclosed in note 14.

c) Emerging Issues Emerging Issues Committee (EIC) – 173, *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*, requires that the Corporation's own credit risk and the credit risk of its counterparties be taken into account in determining the fair value of a financial instrument. The Corporation's consolidated financial statements are not materially impacted from applying this standard.

COMPREHENSIVE INCOME

Section 1530, *Comprehensive Income*, requires the presentation of a statement of comprehensive income and provides guidance for the reporting and display of other comprehensive income. Comprehensive income represents the change in equity of an enterprise during a period from transactions and other events arising from non-owner sources including gains and losses arising on translation of self-sustaining foreign operations, gains and losses from changes in fair value of available for sale financial assets and changes in fair value of the effective portion of cash flow hedging instruments. The Corporation has not recognized any adjustments through other comprehensive income for the years ended December 31, 2011 and 2010.

INCOME TAXES

The Corporation follows the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are likely to be realized. The future income tax assets and liabilities are measured using the enacted or substantively enacted income tax rates and laws that will be in effect when the differences are expected to be recovered or settled.

The effect of a change in income tax rates on future income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense (recovery) is recognized for the estimated income taxes payable (receivable) in the current year.

As approved by the BCUC, the Corporation recovers income tax expense in customer rates based only on income taxes that are currently payable for regulatory purposes, except for certain deferral accounts specifically prescribed by the BCUC. Therefore, current customer rates do not include the recovery of future income taxes related to temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in rates

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

INCOME TAXES (CONTINUED)

when they become payable. An offsetting regulatory asset or liability is recognized for the amount of income taxes that are expected to be collected in rates once they become payable.

Any difference between the expense recognized under Canadian GAAP and that recovered from customers in current rates for income tax expense that is expected to be recovered, or refunded, in future customer rates is subject to deferral treatment (notes 5, 6 and 8).

VARIABLE INTEREST ENTITIES

The Corporation has performed a review of the entities with which it conducts business and has concluded that there are no entities that are required to be consolidated or variable interests that are required to be disclosed under the requirements of Accounting Guideline 15, *Consolidation of Variable Interest Entities*.

FUTURE ACCOUNTING PRONOUNCEMENTS

Adoption of New Accounting Standards

Effective January 1, 2012, the Corporation will be required to adopt a new set of accounting standards. Publicly accountable enterprises in Canada were required to adopt International Financial Reporting Standards (IFRS) effective January 1, 2011, however, qualifying entities with rate-regulated activities were granted an optional one-year deferral for the adoption of IFRS, due to continued uncertainty around the timing and adoption of a rate-regulated accounting standard by the International Accounting Standards Board (IASB).

Due to continued uncertainty around the timing and adoption of a rate-regulated accounting standard by the IASB, the Corporation evaluated the option of adopting United States generally accepted accounting principles (US GAAP), as opposed to IFRS, and has decided to adopt US GAAP effective January 1, 2012. Canadian securities rules allow a reporting issuer to prepare and file its financial statements in accordance with US GAAP by qualifying as a US Securities and Exchange Commission (SEC) Issuer. A SEC Issuer is defined under the Canadian securities rules as an issuer that: (i) has a class of securities registered with the SEC under Section 12 of the *US Securities Exchange Act of 1934,* as amended (the Exchange Act), or (ii) is required to file reports under Section 15(d) of the Exchange Act. The Corporation is currently not an SEC Issuer.

Therefore, on June 6, 2011, the Corporation, along with its ultimate parent company, Fortis, filed an application with the Ontario Securities Commission (the OSC) seeking relief, pursuant to National Policy 11-203 – *Process for Exemptive Relief Applications in Multiple Jurisdictions,* to permit the Corporation to prepare its financial statements in accordance with US GAAP without qualifying as an SEC Issuer (the Exemption). On June 9, 2011 the OSC issued its decision and granted the Exemption for financial years commencing on or after January 1, 2012 but before January 1, 2015, and interim periods therein. The Exemption will terminate in respect of financial statements for annual and interim periods commencing on or after the earlier of: (a) January 1, 2015; or (b) the date on which the Corporation ceases to have activities subject to rate regulation.

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

1. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

FUTURE ACCOUNTING PRONOUNCEMENTS (CONTINUED)

The Corporation's application of Canadian GAAP currently relies primarily on US GAAP for guidance on accounting for rate-regulated activities. The adoption of US GAAP in 2012 is, therefore, expected to result in fewer significant changes to the Corporation's accounting policies as compared to accounting policy changes that may have resulted from the adoption of IFRS. US GAAP guidance on accounting for rate-regulated activities which allows the economic impact of rate-regulated activities to be recognized in the consolidated financial statements in a manner consistent with the timing by which amounts are reflected in customer rates. The Corporation believes that the continued application of rate-regulated accounting, and the associated recognition of regulatory assets and liabilities under US GAAP, accurately reflects the impact that rate-regulation has on the Corporation's consolidated financial position and results of operations.

2. INVENTORIES

During the year ended December 31, 2011, gas in storage inventories of $763.3 million (2010 - $790.0 million) were expensed and reported in cost of natural gas on the consolidated statement of earnings and comprehensive earnings.

3. PROPERTY, PLANT AND EQUIPMENT

2011	**Weighted average depreciation rate**	**Cost**	**Accumulated depreciation**	**Net book value**
Natural gas transmission and distribution systems	**2.56%**	**$ 3,100.9**	**$ (829.8)**	**$ 2,271.1**
Plant, buildings and equipment	**5.04%**	**238.7**	**(84.3)**	**154.4**
Land	**-**	**55.1**	**-**	**55.1**
Assets under construction	**-**	**32.5**	**-**	**32.5**
		$ 3,427.2	**$ (914.1)**	**$ 2,513.1**

2010	Weighted average depreciation rate	Cost	Accumulated depreciation	Net book value
Natural gas transmission and distribution systems	2.57%	$ 2,956.4	$ (756.7)	$ 2,199.7
Plant, buildings and equipment	5.12%	228.0	(81.1)	146.9
Land	-	52.1	-	52.1
Assets under construction	-	67.4	-	67.4
		$ 3,303.9	$ (837.8)	$ 2,466.1

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

3. PROPERTY, PLANT AND EQUIPMENT (CONTINUED)

As allowed by the regulator, during the year ended December 31, 2011, the Corporation capitalized an allowance for debt and equity funds during construction at approved rates of $3.3 million (2010 - $1.6 million) and $4.1 million (2010 - $2.1 million), respectively and approved capitalized overhead of $30.2 million (2010 - $29.0 million), with offsetting inclusions in earnings. Depreciation of property, plant and equipment for the year ended December 31, 2011 totalled $86.4 million (2010 - $85.5 million).

4. INTANGIBLE ASSETS

2011	**Cost**	**Accumulated depreciation**	**Net book value**
Software	**$ 91.0**	**$ (22.1)**	**$ 68.9**
Land rights	**45.7**	**(0.7)**	**45.0**
Other	**2.5**	**(1.3)**	**1.2**
Assets under construction	**1.5**	**-**	**1.5**
	$ 140.7	**$ (24.1)**	**$116.6**

2010	Cost	Accumulated depreciation	Net book value
Software	$ 57.3	$ (27.0)	$ 30.3
Land rights	45.3	(0.7)	44.6
Other	2.5	(1.2)	1.3
Assets under construction	18.7	-	18.7
	$ 123.8	$ (28.9)	$ 94.9

There was no impairment of intangible assets for the years ended December 31, 2011 and 2010.

The land rights are not subject to amortization but were amortized historically until it was determined that the useful life of the land rights was indefinite at which time amortization ceased and the land rights are tested for impairment annually.

During the year ended December 31, 2011, $28.6 million (2010 - $5.3 million) of intangible assets subject to amortization were acquired and $0.8 million (2010 - $0.7 million) were developed.

During the year ended December 31, 2011, $0.5 million (2010 - $14.5) of intangible assets not subject to amortization were acquired and nil (2010 – nil) were developed.

During the year ended December 31, 2011, $13.0 million (2010 - $9.3 million) of fully amortized software assets were retired.

Amortization of intangible assets for the year ended December 31, 2011 totalled $8.1 million (2010 - $8.2 million).

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

4. INTANGIBLE ASSETS (CONTINUED)

Amortization of software is recorded on a straight-line basis using an average amortization rate of 8.8 per cent. Amortization of other intangible assets is recorded on a straight-line basis using an amortization rate of 2.9 per cent. Amortization rates for regulated intangible assets are approved by the BCUC, and for non-regulated intangible assets require the use of management estimates of the useful lives of assets.

5. RATE STABILIZATION ACCOUNTS

	2011	2010
Current Assets		
CCRA	**$ 73.1**	$ 99.2
MCRA	**-**	3.5
Gross up of current rate stabilization accounts for future income taxes	**(4.6)**	(6.4)
	68.5	96.3
Current Liabilities		
RSAM	**(8.4)**	(2.6)
MCRA	**(5.6)**	-
Gross up of current rate stabilization accounts for future income taxes	**(4.7)**	(1.0)
	(18.7)	(3.6)
Long-Term Liabilities		
RSAM	**(16.8)**	(5.3)
Gross up of long-term rate stabilization accounts for future income taxes	**(5.6)**	(1.8)
	(22.4)	(7.1)
Net rate stabilization accounts	**$ 27.4**	$ 85.6

The current portion of the rate stabilization accounts represents the amounts expected to be recovered or refunded in rates over the next year. Actual recoveries (refunds) will vary depending on actual natural gas consumption and recovery amounts approved by the BCUC.

The RSAM account is anticipated to be refunded in rates over three years. Refund of the RSAM balance is dependent upon annually approved rates and actual gas consumption volumes. The MCRA and CCRA accounts are anticipated to be fully recovered or paid within the next fiscal year.

The mark-to-market on the natural gas derivatives included in the CCRA account is $86.8 million (2010 - $120.4 million).

The future income taxes on rate stabilization accounts resulted from the Canadian Accounting Standards Board (AcSB) amendment to Section 3465, *Income Taxes* requiring the recognition of future income tax liabilities and assets as well as offsetting amounts included in the rate stabilization accounts. The mark-to-market on the natural gas derivatives offsets the CCRA account resulting in a net receivable position. There are no timing differences for tax purposes on the mark-to-market on the natural gas derivatives.

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

5. RATE STABILIZATION ACCOUNTS (CONTINUED)

In the absence of rate regulation, the costs in the rate stabilization accounts above would have been expensed as incurred. The impact on the consolidated statements of earnings and comprehensive earnings would have been as follows:

	2011	2010
Increase in natural gas transmission and distribution revenue	**$ 305.0**	$ 317.8
Increase in cost of natural gas	**(279.6)**	(350.2)
Decrease (increase) in income tax expense	**1.1**	(0.2)
Increase (decrease) in other comprehensive income related to gas derivatives	**33.5**	(19.3)

6. OTHER ASSETS

	2011	2010
Deferred charges		
Subject to rate regulation and approved for recovery in rates		
Deferred losses on disposal of utility capital assets	**$ 21.0**	$ 14.8
Energy Efficiency and Conservation Program	**20.7**	10.6
Income taxes recoverable on post-employment benefits	**18.3**	18.3
Gross up of regulated other assets for future income taxes	**16.4**	6.8
Customer care enhancement	**11.2**	-
Pension cost variance	**9.6**	1.6
Alternative energy projects	**8.5**	4.0
Deferred removal costs	**4.7**	1.4
Tilbury land purchase	**0.6**	3.3
Olympic security costs	**0.4**	1.2
Other items approved for recovery in rates	**6.8**	5.4
	118.2	67.4
Regulated asset for future income taxes	**282.6**	263.5
Pension assets (note 10)	**24.9**	25.9
Long-term receivables	**8.9**	8.9
	$ 434.6	$ 365.7

Amortization of these deferred charges in rates for the year ended December 31, 2011 totalled $4.0 million (2010 - $1.8 million).

The deferred losses on disposal of utility capital assets is a regulatory deferral account that was approved by the BCUC in the 2010/2011 NSA and accumulates gains and losses on the sale or removal of utility capital assets. FEI has applied for recovery of this account over 20 years.

The deferral account for the Energy Efficiency and Conservation Program relates to costs incurred in relation to a program approved by the BCUC that provides energy efficient incentives to residential and commercial customers. The BCUC has approved the recovery of these costs in rates over a ten-year period.

6. OTHER ASSETS (CONTINUED)

The deferral account for income taxes on post-employment benefits relates to income tax amounts on post-employment benefit expense. The BCUC allows post-employment benefits to be collected from customers through rates calculated on the accrual basis, rather than a cash paid basis, which produces a timing difference for income tax purposes similar to a future income tax asset. However, due to prior regulatory decisions this is presented as a regulatory other asset. In years prior to 2009 the Corporation accounted for income taxes using the taxes payable basis of accounting, thus the tax effect of this timing difference is included in other assets, and will be reduced as cash payments for post-employment benefits exceed required accruals and amounts collected from customers in rates.

The deferral account for future income taxes on regulated other assets and the regulated asset for future income taxes resulted from the AcSB's amendment to Section 3465, *Income Taxes,* requiring the recognition of future income tax liabilities and assets as well as offsetting regulated assets or liabilities.

The Customer Care Enhancement (CCE) deferral captures all incremental costs associated with the project that were incurred prior to the project implementation date of January 1, 2012, for the purpose of permitting cost recovery, as well as any amounts related to the timing of when the CCE project is available for use and when it is actually added into rate base. These costs will be transferred to rate base and amortized through delivery rates commencing January 1, 2012 over a three year period.

The pension cost variance account accumulates differences between pension expense and other post-employment benefit expense that is approved for recovery in rates and actuarial pension expense. Amounts are recovered in rates over a three year period.

The alternative energy projects deferral account captures the costs and revenue associated with the investment in alternative energy solutions. The recovery of this account will be determined at a future period.

The deferred removal costs account is a regulatory deferral account that was approved by the BCUC in the 2010/2011 NSA and accumulates actual removal costs incurred in excess of or below the approved amount. These costs will be recovered from, or refunded to, customers in future rates beginning in 2012.

The Tilbury land purchase deferral account captures the cost of the land that FEI will be seeking to subdivide and sell. A portion of the land was sold in the fourth quarter of 2011 and the proceeds were credited against this deferral account. If the remaining parcel of land is not sold by January 1, 2014, the amount will be reclassed to property, plant and equipment and will be included in rate base.

The Olympic security costs deferral account captures the security costs incurred related to the 2010 Olympic and Paralympics games. These costs will be recovered in rates over a three year period beginning in 2011.

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

6. OTHER ASSETS (CONTINUED)

Deferred charges that have been aggregated in the table above and in the table in "Other Long-term Liabilities and Deferred Credits" in note 8 as other items approved for recovery (refund) in rates relate to more than 36 deferral accounts, none of which exceed $1.5 million individually. All of these accounts have been approved by regulators in prior annual rate approvals or orders and are being amortized over various periods depending on the nature of the costs.

In the absence of rate regulation, the deferred charges in the above table that were incurred in the period would have been recorded in income, except for the costs related to the pension asset, Tilbury land purchase, deferred capital costs associated with the alternative energy projects and long-term receivables. The impact on the consolidated statements of earnings and comprehensive earnings would have been as follows:

	2011	2010
Increase (decrease) in natural gas transmission and distribution revenue	**$ 8.0**	$ (3.9)
Increase in cost of natural gas	**(0.5)**	(0.1)
Increase in operation and maintenance costs	**(63.7)**	(19.0)
Decrease in depreciation and amortization	**4.0**	1.8
Increase in financing costs	**(2.3)**	(0.6)
Increase in income tax expense	**(16.6)**	(6.1)
Net decrease in earnings	**$ (71.1)**	$ (27.9)

7. LONG-TERM DEBT

	2011	2010
(a) Purchase Money Mortgages:		
11.80% Series A, due September 30, 2015	**$ 74.9**	$ 74.9
10.30% Series B, due September 30, 2016	**200.0**	200.0
(b) Debentures and Medium-Term Note Debentures:		
6.95% Series 11, due September 21, 2029	**150.0**	150.0
6.50% Series 18, due May 1, 2034	**150.0**	150.0
5.90% Series 19, due February 26, 2035	**150.0**	150.0
5.55% Series 21, due September 25, 2036	**120.0**	120.0
6.00% Series 22, due October 2, 2037	**250.0**	250.0
5.80% Series 23, due May 13, 2038	**250.0**	250.0
6.55% Series 24, due February 24, 2039	**100.0**	100.0
4.25% Series 25, due December 9, 2041	**100.0**	-
Obligations under capital leases, at 3.98% (2010 – 2.85%)	**14.5**	13.0
Total long-term debt	**1,559.4**	1,457.9
Less: current portion of long-term debt	**2.9**	2.6
Less: long-term debt issue costs	**14.0**	13.2
	$ 1,542.5	$ 1,442.1

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

7. LONG-TERM DEBT (CONTINUED)

a) Purchase Money Mortgages:

The Series A and Series B Purchase Money Mortgages are secured equally and rateably by a first fixed and specific mortgage and charge on the Corporation's Coastal Division assets, and are subject to the restrictions of the Trust Indenture dated December 3, 1990. The aggregate principal amount of Purchase Money Mortgages that may be issued under the Trust Indenture is limited to $425 million.

b) Debentures and Medium-Term Note Debentures:

The Corporation's debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 1, 1977, as amended and supplemented.

On December 9, 2011, FEI issued $100.0 million of Medium-Term Note Debentures at a coupon interest rate of 4.25 per cent. The debentures mature on December 9, 2041 and are unsecured and subject to the restrictions of the Trust Indenture. The net proceeds were used to repay credit-facility borrowings incurred in support of working capital requirements and capital expenditures.

Long-term debt issue costs are amortized using the effective interest rate method.

The Corporation's Series B Purchase Money Mortgages, and Series 11, Series 18, Series 19, Series 21, Series 22, Series 23, Series 24 and Series 25 Medium-Term Note Debentures are redeemable in whole or in part at the option of the Corporation at a price equal to the greater of the Canada Yield Price, as defined in the applicable Trust Indenture, and the principal amount of the debt to be redeemed, plus accrued and unpaid interest to the date specified for redemption. The Canada Yield Price is calculated as an amount that provides a yield slightly above the yield on an equivalent maturity Government of Canada bond. The Corporation's Series A Purchase Money Mortgages are not redeemable.

Required principal repayments over the next five years and thereafter are as follows:

	2011
2012	**$ 2.9**
2013	**2.9**
2014	**2.9**
2015	**77.8**
2016	**202.9**
Thereafter	**1,270.0**
	$ 1,559.4

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

8. OTHER LONG-TERM LIABILITIES AND DEFERRED CREDITS

	2011	2010
Pension and other post-employment benefit liabilities (note 10)	**$ 65.4**	$ 60.7
Deferred gains on sale of natural gas transmission and distribution assets	**34.1**	38.1
Deferred credits		
Subject to rate regulation and approved for recovery in rates		
Income tax variance	**11.9**	3.2
Gross up of regulated deferred credits for future income taxes	**8.6**	10.0
Southern Crossing Pipeline (SCP) mitigation revenues	**8.5**	5.4
Deferred interest mechanism	**7.6**	5.1
IFRS transitional adjustments	**6.3**	7.8
Property tax variance	**2.5**	1.1
Deferred interest on MCRA	**2.2**	2.1
Insurance cost variance	**1.1**	0.7
2010 revenue surplus	**-**	6.5
Earnings sharing and capital incentive mechanism	**-**	5.2
Other items approved for refund in rates	**2.5**	2.1
Other deferred credits		
Ministry of Energy, Mines and Petroleum Resources funds	**4.2**	4.2
Other	**0.1**	1.0
	155.0	153.2
Less: current portion of other long-term liabilities and deferred credits	**-**	11.7
	$ 155.0	$ 141.5

The deferred gains on sale of natural gas transmission and distribution assets occurred upon the sale and leaseback of FEI's pipeline assets to certain municipalities in 2001, 2002, 2004 and 2005. The pre-tax gains of $70.5 million on combined cash proceeds of $141.1 million are being amortized over the 17-year terms of the operating leases that commenced at the time of the sale transactions. These operating lease commitments are included in the table in note 16.

The income tax variance account captures the impact on tax expense due to changes in tax laws or accepted accessing practices, audit reassessments, accounting policy changes and tax rate changes. Amounts are recovered in rates over three years.

The future income taxes on regulated deferred credits resulted from the AcSB's amendment to Section 3465, *Income Taxes* requiring the recognition of future income tax liabilities and assets as well as offsetting regulated assets or liabilities.

The SCP mitigation revenues deferral account relates to revenue received from third parties for the use of the SCP transportation capacity that has not been utilized by the firm transportation agreement customers and revenue received from third parties for the use of the SCP west to east transmission system. This account is used to record differences between actual revenues from SCP mitigation and what has been approved in the current revenue requirement. Amounts are being amortized to income over three years.

8. OTHER LONG-TERM LIABILITIES AND DEFERRED CREDITS (CONTINUED)

The Corporation has a deferred interest mechanism which has been approved by the BCUC that requires that variances due to differences in long-term borrowings and long-term and short-term interest rates from those that have been approved in rates be returned to customers in future rates. The impact of this mechanism was to increase financing costs for the year ended December 31, 2011 by $4.3 million (2010 – $0.9 million) from what otherwise would be reported. The balance of the deferred interest account is being amortized on a straight-line basis over three years.

The IFRS transitional adjustments deferral account contains a one-time transfer of the existing gain from the general plant accumulated amortization balance as part of the conversion to IFRS. The balance will be recovered from customers over a yet to be determined period.

The property tax variance account accumulates differences between property tax that is approved for recovery in rates and actual property tax. Amounts are returned to customers in rates over three years.

The deferred interest on MCRA is the interest calculated on the difference between the actual and forecasted average balance of the MCRA account multiplied by the composite interest rate. Amounts are returned to customers in rates in the following year.

The insurance cost variance account accumulates differences between insurance expense that is approved for recovery in rates and actual insurance expense. Amounts are returned to customers in rates in the following year.

The 2010 revenue surplus deferral account captured the FEI forecast 2010 revenue surplus resulting from the BCUC approved rate freeze for FEI for 2010. The surplus was fully applied to reduce rates in 2011.

The earnings sharing and capital incentive mechanism includes the earnings sharing which is a mechanism agreed to in FEI's multi-year agreement that expired at the end of 2009 to share, on a 50/50 basis, amounts earned by FEI on its regulated activities that exceeded or were less than amounts allowed by the BCUC in the cost-of-service allowed return calculations. Also, included in this deferral account is the capital incentive mechanism which allowed sharing on a 50/50 basis of capital spend that was less than the formula capital calculated for the 2003-2009 performance-based rate-setting period. These amounts are shared on an after-tax basis, and are being returned to customers over a two year period which began in 2010.

The Ministry of Energy, Mines and Petroleum Resources funds are funds the Corporation received from the Ministry of Energy, Mines and Petroleum Resources of the Province of BC in advance of expenditures. The funds received are in support of LiveSmart BC's energy conservation and efficiency goals and are focused on the Efficiency Incentive Program for low-income households. The Corporation will use the funds to reduce the consumption of natural gas by low-income residences served by FEI.

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

8. OTHER LONG-TERM LIABILITIES AND DEFERRED CREDITS (CONTINUED)

Other deferred credits include an unfunded defined contribution pension liability. The unfunded defined contribution pension liability relates to a supplementary employee retirement plan for which benefits are based upon employee earnings.

Amortization of these deferred credits in rates for the year ended December 31, 2011 totalled $9.1 million (2010 - $4.3 million).

In the absence of rate regulation, the current period impact of other long-term liabilities and deferred credits in the above table would have been recorded in income, aside for the pension and other post-employment benefit liabilities, the deferred gains on sale of natural gas transmission and distribution assets and the other deferred credits.

The impact on the consolidated statements of earnings and comprehensive earnings would have been as follows:

	2011	2010
(Decrease) increase in natural gas transmission and distribution revenue	**$ (15.7)**	$ 1.9
Increase in cost of natural gas	**-**	(0.4)
Decrease in operation and maintenance costs	**14.7**	0.1
Decrease in property and other taxes	**2.2**	0.6
Increase in depreciation and amortization	**(9.1)**	(4.3)
Decrease in financing costs	**6.4**	1.0
Decrease (increase) in income tax expense	**3.0**	(1.5)
Net increase (decrease) in earnings	**$ 1.5**	$ (2.6)

9. SHARE CAPITAL AND CONTRIBUTED SURPLUS

AUTHORIZED SHARE CAPITAL

The Corporation is authorized to issue 500,000,000 common shares, 100,000,000 first preference shares and 100,000,000 second preference shares, all without par value. Changes in the issued and outstanding common shares are as follows:

	2011		2010	
	Number	**Amount**	Number	Amount
Outstanding, beginning of year	**63,010,782**	**$ 719.0**	59,591,732	$ 594.0
Issued	**-**	**-**	3,419,050	125.0
Outstanding, end of year	**63,010,782**	**$ 719.0**	63,010,782	$ 719.0

In January 2010, the Corporation issued 3,419,050 common shares for total proceeds of $125.0 million. The issuance was a result of the BCUC increasing the Corporation's common equity component in capital structure allowed for rate making purposes from 35.01 per cent to 40.00 per cent.

9. SHARE CAPITAL AND CONTRIBUTED SURPLUS (CONTINUED)

CONTRIBUTED SURPLUS

Income tax benefits in the amount of $10.1 million (2010 – $7.7) relating to transactions with entities under common control were recorded as a credit to contributed surplus in 2011.

DIVIDEND POLICY

As part of its approval of the acquisition of FortisBC Holdings Inc. (the Corporation's parent) by Fortis Inc., the BCUC imposed a number of conditions intended to ring-fence FEI from FortisBC Holdings Inc. These restrictions included a prohibition on the payment of dividends unless the Corporation has in place at least as much common equity as that deemed by the BCUC for rate-making purposes. The Corporation must maintain a percentage of common equity to total capital that is at least as much as that determined by the BCUC from time to time for rate-making purposes. Dividends from the Corporation will not be allowed by the regulator if the requisite equity is not in place. The Corporation's dividend policy is intended to ensure that it maintains at least as much common equity as that deemed by the BCUC for rate-making purposes.

10. EMPLOYEE BENEFIT PLANS

The Corporation is a sponsor of pension plans for eligible employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements, which provide pension benefits in excess of statutory limits, and defined contributory plans. The Corporation also provides post-employment benefits other than pensions for retired employees. The following is a summary of each type of plan:

DEFINED BENEFIT PLANS

Retirement benefits for unionized employees under the defined benefit plans are based on employees' years of credited service and remuneration. Corporation contributions to the plan are based upon independent actuarial valuations. The most recent actuarial valuation of the defined benefit pension plans for funding purposes was at December 31, 2010 and the next required valuation is as of December 31, 2013. The expected weighted average remaining service life of employees covered by the defined benefit pension plans is 9.7 years (2010 – 9.2 years).

Effective in 2007, all employees became participants in a defined benefit pension plan in which costs are split evenly between the employees and employer. The current employees were grandfathered in their respective defined contribution and defined benefit plans and those plans were closed to all new members. The most recent actuarial valuation of this defined benefit pension plan for funding purposes was December 31, 2009 and the date of the next required valuation is December 31, 2012. The expected weighted average remaining service life of employees covered by this defined benefit pension plan is 10.9 years (2010 – 10.9 years).

10. EMPLOYEE BENEFIT PLANS (CONTINUED)

DEFINED CONTRIBUTION PLAN

Effective in 2000, all new non-union employees became members of defined contribution pension plans. Corporation contributions to the plan are based upon employee age and pensionable earnings for employees. Effective in 2007, all new employees of the Corporation became members of the defined benefit plan described above.

SUPPLEMENTAL PLANS

Certain employees are eligible to receive supplemental benefits under both the defined benefit and defined contribution plans. The supplemental plans provide pension benefits in excess of statutory limits. The supplemental plans are unfunded and certain plans are secured by letters of credit.

OTHER POST-EMPLOYMENT BENEFITS

The Corporation provides certain retired employees with other post-employment benefits that include, depending on circumstances, supplemental health, dental and life insurance coverage. Post-employment benefits are unfunded and annual expense is recorded on an accrual basis based on independent actuarial determinations, considering among other factors, health care cost escalation. The most recent actuarial valuation was completed as at December 31, 2010 and the next required valuation is as of December 31, 2013. The expected weighted average remaining service life of employees covered by these benefit plans is 12.9 years (2010 – 12.9 years).

The Corporation measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 each year. The financial positions of the employee defined benefit pension plans and other benefit plans are presented in aggregate in the tables below:

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

10. EMPLOYEE BENEFIT PLANS (CONTINUED)

OTHER POST-EMPLOYMENT BENEFITS (CONTINUED)

	Defined benefit pension plans		Other benefit plans	
	2011	2010	**2011**	2010
Plan assets				
Fair value, beginning of year	**$ 261.9**	$ 236.9	**$ -**	$ -
Actual return on plan assets	**20.1**	21.6	**-**	-
Corporation contributions	**11.6**	8.4	**1.5**	1.4
Contributions by members	**8.6**	6.9	**-**	-
Benefit payments	**(13.2)**	(11.6)	**(1.5)**	(1.4)
Other	**(0.1)**	(0.3)	**-**	-
Fair value, end of year	**288.9**	261.9	**-**	-
Accrued benefit obligation				
Obligation, beginning of year	**314.9**	264.4	**69.2**	57.8
Current service cost	**8.9**	6.7	**1.5**	1.4
Interest cost	**16.7**	15.9	**3.6**	3.5
Contributions by members	**8.6**	6.9	**-**	-
Benefit payments	**(13.2)**	(11.6)	**(1.5)**	(1.4)
Plan amendments	**-**	(4.8)	**-**	-
Actuarial loss	**38.2**	37.4	**20.5**	7.9
Balance, end of year	**374.1**	314.9	**93.3**	69.2
Plan deficiency	**(85.2)**	(53.0)	**(93.3)**	(69.2)
Unamortized transitional benefit	**(1.9)**	(3.4)	**-**	-
Unamortized actuarial loss	**110.8**	82.9	**44.4**	25.4
Unamortized past service costs	**(3.3)**	(3.5)	**(12.0)**	(14.1)
Accrued benefit asset (liability)	**$ 20.4**	$ 23.0	**$ (60.9)**	$ (57.9)
Represented by				
Pension assets	**$ 24.9**	$ 25.9	**$ -**	$ -
Accrued benefit liability	**(4.5)**	(2.9)	**(60.9)**	(57.9)
	$ 20.4	$ 23.0	**$ (60.9)**	$ (57.9)

The net accrued benefit liability is included in other long-term liabilities and deferred credits (note 8) and the pension asset is included in other assets (note 6).

Included in the accrued benefit obligation and fair value of the plan assets at year-end are the following amounts in respect of plans with accrued benefit obligations in excess of fair value of assets:

	Defined benefit pension plans		Other benefit plans	
	2011	2010	**2011**	2010
Accrued benefit obligations:				
Unfunded plans	**$ 11.6**	$ 9.9	**$ 93.3**	$ 69.2
Funded plans	**362.5**	305.0	**-**	-
	374.1	314.9	**93.3**	$ 69.2
Fair value of plan assets	**288.9**	261.9	**-**	-
Funded status deficit	**$ (85.2)**	$ (53.0)	**$ (93.3)**	$ (69.2)

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

10. EMPLOYEE BENEFIT PLANS (CONTINUED)

OTHER POST-EMPLOYMENT BENEFITS (CONTINUED)

The accrued benefit obligations for certain unfunded pension benefit plans are secured by letters of credit.

The net benefit plan expense is as follows:

	Defined benefit pension plans		Other benefit plans	
	2011	2010	**2011**	2010
Current service cost	**$ 8.9**	$ 6.7	**$ 1.5**	$ 1.4
Interest cost on projected benefit obligations	**16.7**	15.9	**3.6**	3.5
Actual (return) loss on plan assets	**(20.1)**	(21.6)	**-**	-
Net actuarial losses	**38.2**	37.4	**20.5**	7.9
Plan amendments	**-**	(4.8)	**-**	
Other	**0.1**	0.3	**-**	-
Net benefit plan expense before adjustments	**43.8**	33.9	**25.6**	12.8
Adjustments to recognize the long-term nature of employee future benefit costs:				
Difference between actual and expected loss (return) on plan assets	**3.2**	4.5	**-**	-
Difference between actual and recognized actuarial gains in year	**(31.1)**	(34.3)	**(19.0)**	(7.0)
Difference between actual and recognized past service costs in year	**(0.2)**	5.3	**(2.1)**	(2.2)
Amortization of transitional benefit	**(1.5)**	(1.8)	**-**	-
Net benefit plan expense	**$ 14.2**	$ 7.6	**$ 4.5**	$ 3.6

BENEFIT PLAN ASSETS

The weighted-average asset allocation by asset category of the Corporation's defined benefit pension plans and other funded benefit plans is as follows:

	Defined benefit pension plans	
	2011	2010
Equity securities	**47%**	47%
Fixed income securities	**42%**	42%
Other assets	**11%**	11%
Total assets	**100%**	100%

The pension plans do not directly hold any shares of the Corporation's parent or affiliated companies.

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

10. EMPLOYEE BENEFIT PLANS (CONTINUED)

SIGNIFICANT ASSUMPTIONS

The discount rate assumption used in determining pension and post-retirement benefit obligations and net benefit expense reflects the market yields, as of the measurement date, on Corporate AA bonds. The expected rate of return on plan assets assumption is reviewed annually by management, in conjunction with actuaries. The assumption is based on the expected returns for the various asset classes, weighted by the portfolio allocation.

The weighted average significant actuarial assumptions used to determine the accrued benefit obligation and the benefit plan expense are as follows:

	Defined benefit pension plans		Other benefit plans	
	2011	2010	**2011**	2010
Accrued benefit obligation				
Discount rate at December 31, based on AA Corporate bonds	**4.25%**	5.25%	**4.25%**	5.25%
Rate of compensation increase	**2.89%**	3.35%	**-**	-
Net benefit plan expense				
Discount rate at January 1, based on AA Corporate bonds	**5.25%**	6.00%	**5.25%**	6.00%
Expected rate of return on plan assets	**6.75%**	7.00%	**-**	-

The assumed health-care cost trend rates for other post-employment benefit plans are as follows:

	2011	2010
Extended health benefits		
Initial health-care cost trend rate	**8.0%**	8.0%
Annual rate of decline in trend rate	**0.5%**	0.5%
Ultimate health-care cost trend rate	**5.0%**	5.0%
Year the rate reaches the ultimate trend rate	**2017**	2017
Medical Services Plan Benefits Premium trend rate	**6.0%**	6.0%

A one percentage-point change in assumed health-care cost trend rates would have the following effects:

2011	**One percentage-point increase**	**One percentage-point decrease**
Effect on the total of the service cost and interest cost components of the benefit plan expense	**$ 0.5**	**$ 0.4**
Effect on accrued benefit obligation	**7.8**	**7.2**

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

10. EMPLOYEE BENEFIT PLANS (CONTINUED)

CASH FLOWS

Total cash contributions for employee benefit plans consist of:

	Employee benefit plans	
	2011	2010
Funded plans	**$ 10.9**	$ 7.7
Beneficiaries of unfunded plans	**2.2**	2.1
Total	**$ 13.1**	$ 9.8

See note 16 for the 2012 contributions for the defined pension benefit plans and other benefit plans.

IMPACT OF RATE REGULATION

As required by the regulator, the Corporation is required under its approved cost of service model to defer the amounts of pension benefit expense that exceed or are less than the amounts approved by the regulator to be recovered in rates each year. During the year ended December 31, 2011, the Corporation has deferred pension expense of $8.0 million that was greater than (2010 – $1.6 million greater than) the amount approved by the regulator to be recovered in rates in 2011.

11. FINANCING COSTS

	2011	2010
Interest and expense on long-term debt	**$ 105.1**	$ 102.9
Interest on short-term debt	**2.5**	1.2
Interest capitalized	**(3.3)**	(1.6)
Total	**$ 104.3**	$ 102.5

As allowed by the regulator, during the year ended December 31, 2011, the Corporation capitalized interest for borrowing requirements for construction of assets that have not been included in rate base of $3.3 million (2010 - $1.6 million).

12. SUPPLEMENTARY INFORMATION TO CONSOLIDATED STATEMENTS OF CASH FLOWS

	2011	2010
Supplemental cash flow information		
Interest paid in the period	**$ 103.8**	$ 102.5
Income taxes paid in the period	**3.4**	22.0

13. INCOME TAXES

PROVISION FOR INCOME TAXES

	2011	2010
Current income tax expense	**$ 28.2**	$ 30.4
Future income taxes	**17.9**	6.9
Regulatory adjustment	**(19.1)**	(7.5)
	(1.2)	(0.6)
Income tax expense	**$ 27.0**	$ 29.8

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

13. INCOME TAXES (CONTINUED)

VARIATION IN EFFECTIVE INCOME TAX RATE

Consolidated income taxes vary from the amount that would be computed by applying the Canadian Federal and British Columbia combined statutory income tax rate of 26.5 per cent (2010 – 28.5 per cent) to earnings before income taxes as shown in the following table:

	2011	2010
Earnings before income taxes	**$ 128.9**	$ 123.0
Combined statutory income tax rate	**26.5%**	28.5%
Combined income taxes at statutory rate	**$ 34.2**	$ 35.1
Items capitalized for accounting purposes but expensed for income tax purposes	**(5.4)**	(4.6)
Difference between capital cost allowance and amounts claimed for accounting purposes	**(1.6)**	(0.8)
Pension costs	**(0.9)**	(0.2)
Other regulated temporary differences	**(0.3)**	(0.7)
Non deductible expenses and non taxable income	**(1.1)**	(0.5)
Other	**2.1**	1.5
Actual consolidated income taxes	**$ 27.0**	$ 29.8
Effective income tax rate	**20.95%**	24.23%

FUTURE INCOME TAXES

Future income taxes are provided for temporary differences. Future income tax assets and liabilities are comprised of the following:

	2011	2010
Future income tax liability (asset)		
Property, plant and equipment	**$ 271.0**	$ 268.7
Intangible assets	**17.7**	7.7
Other assets	**26.9**	14.0
Other long-term liabilities and deferred credits	**(28.3)**	(25.9)
Employee future benefits	**4.3**	5.9
Share issue and debt financing costs	**2.1**	1.9
Net future income tax liability	**$ 293.7**	$ 272.3
Current future income tax asset	**$ (10.1)**	$ (8.6)
Current future income tax liability	**-**	1.3
Long-term future income tax liability	**303.8**	279.6
Net future income tax liability	**$ 293.7**	$ 272.3

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

14. FINANCIAL INSTRUMENTS

FAIR VALUE ESTIMATES

	December 31, 2011		December 31, 2010	
	Carrying value	**Estimated fair value**	Carrying value	Estimated fair value
Held for trading				
Cash and cash equivalents [1]	**$ 17.2**	**$ 17.2**	$ 15.2	$ 15.2
Loans and receivables				
Accounts receivable [1,2]	**238.4**	**238.4**	298.1	298.1
Long-term receivables[1,2]	**8.9**	**8.9**	8.9	8.9
Other financial liabilities				
Short-term notes [1,2]	**65.0**	**65.0**	178.0	178.0
Accounts payable and accrued liabilities [1,2]	**303.7**	**303.7**	357.9	357.9
Long-term debt, including current portion [3,4,5]	**1,545.4**	**2,026.1**	1,444.7	1,735.8

1 Due to the nature and/or short-term maturity of these financial instruments, carrying value approximates fair value.
2 Carrying value approximates amortized cost.
3 Carrying value is measured at amortized cost using the effective interest rate method.
4 Carrying value at December 31, 2011 is net of unamortized deferred financing costs of $14.0 million (2010 - $13.2 million). The majority of the Corporation's long-term debt relates to regulated operations which enables the Corporation to recover the existing financing charges through rates or tolls.
5 Fair value is calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at December 31, 2011 and 2010, or by using available quoted market prices.

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates cannot be determined with precision as they are subjective in nature and involve uncertainties and matters of judgment.

Interest expense associated with the Corporation's short-term borrowings and long-term debt is disclosed in note 11 to these consolidated financial statements.

DERIVATIVE INSTRUMENTS

The Corporation hedges its exposure to fluctuations in natural gas prices and foreign exchange rates through the use of derivative instruments. FEI's price risk management strategy aims to (i) improve the likelihood that natural gas prices remain competitive with electricity rates, (ii) dampen price volatility on customer rates and (iii) reduce the risk of regional price disconnects. In July 2010, the BCUC ordered the suspension of all commodity hedging activity and directed FEI to undertake a review of the primary objectives of the Price Risk Management Plan (PRMP). In January 2011, FEI filed a review report and submitted a revised 2011-2014 PRMP, based on recommendations arising from the review report. On July 12, 2011, the BCUC issued its decision on the review report and determined that commodity hedging in the current environment was not a cost effective means to meet the objectives of competitiveness and rate stability. The BCUC concurrently denied FEI's 2011-2014 PRMP with the exception of certain elements to address the risk of regional price disconnects. As a result, FEI has suspended all commodity hedging activity with the exception of basis swaps to reduce the risk of Sumas market price disconnects.

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

14. FINANCIAL INSTRUMENTS (CONTINUED)

DERIVATIVE INSTRUMENTS (CONTINUED)

The existing hedging contracts continue in effect through to their maturity and FEI's ability to fully recover the commodity cost of gas in customer rates remains unchanged.

The table below indicates the valuation of the derivative instruments as at December 31, 2011 and 2010.

Asset (Liability)			**December 31, 2011**		December 31, 2010	
	Number of contracts	**Term to maturity (years)**	**Carrying value**	**Fair value**	Carrying value	Fair value
Foreign exchange forward	**1**	**0.3**	**$ (0.1)**	**$ (0.1)**	$ (0.2)	$ (0.2)
Natural Gas Commodity swaps and options and gas purchase contract premiums	**168**	**Up to 2.8**	**(86.8)**	**(86.8)**	(120.4)	(120.4)

The following tables summarize the fair value measurements of natural gas derivative contracts and foreign exchange forward contract as of December 31, 2011 and 2010, based on the three levels that distinguish the level of pricing observability utilized in measuring fair value.

Asset (Liability)	**December 31, 2011**			
	Total fair value	**Level 1 – Quoted prices in active markets for identical assets**	**Level 2 – Significant other observable inputs**	**Level 3 – Significant unobservable inputs**
Foreign exchange forward	**$(0.1)**	**-**	**$ (0.1)**	**-**
Natural gas commodity swaps and options and gas purchase contract premiums	**(86.8)**	**-**	**(86.8)**	**-**

Asset (Liability)	December 31, 2010			
	Total fair value	Level 1 – Quoted prices in active markets for identical assets	Level 2 – Significant other observable inputs	Level 3 – Significant unobservable inputs
Foreign exchange forward	$ (0.2)	$ -	$ (0.2)	$ -
Natural gas commodity swaps and options and gas purchase contract premiums	(120.4)	-	(120.4)	-

The natural gas derivatives' fair value reflects only the value of the natural gas derivatives and not the offsetting change in value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Corporation would receive or (pay) to terminate the contracts at the stated dates. The natural gas derivatives' fair values have been determined using published market prices for

14. FINANCIAL INSTRUMENTS (CONTINUED)

DERIVATIVE INSTRUMENTS (CONTINUED)

natural gas commodities while the foreign exchange forward contract uses the market foreign exchange rate in effect at the period end.

The derivatives entered into by the Corporation relate to regulated operations and any resulting gains or losses are recorded in rate stabilization accounts or deferral accounts, subject to regulatory approval, and are passed through to customers in future rates.

RISK MANAGEMENT

Exposure to credit risk, liquidity risk, market risk, and natural gas commodity price risk arises in the normal course of the Corporation's business.

CREDIT RISK

Credit risk is the risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument. For cash and cash equivalents, derivative assets, accounts receivable, and other receivables due from customers, the Corporation's credit risk is limited to the carrying value on the balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk.

The Corporation is exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments, including natural gas commodity swaps and options. Because the Corporation deals with high credit-quality institutions, in accordance with established credit-approval practices, the Corporation does not expect any counterparties to fail to meet their obligations. Counter-party credit exposures are monitored by individual counterparty and by category of credit rating, and are subject to approved limits. The counter-parties with which the Corporation has significant transactions are A-rated entities or better. The Corporation uses netting arrangements to reduce credit risk and net settles payments with counter-parties where net settlement provisions exist.

In the case of commercial and industrial customers credit risk is managed by checking a corporation's creditworthiness and financial strength both before commencing and during the business relationship. For residential customers, creditworthiness is ascertained normally before commencing commodity delivery by an appropriate mix of internal and external information to determine the payment mechanism required to reduce credit risk to an acceptable level. Certain customers will only be accepted on a prepayment basis. The Corporation manages its exposure to credit risk associated with all customers by monitoring an aging of receivables and by monitoring groupings of customers according to method of payment or profile.

Receivables from customers are generally considered to be fully performing until such time as the payment that is due remains outstanding past the contractual due date. The contractual due date is generally 22 days. The aging analysis of the Corporation's consolidated accounts receivable, net of an allowance for doubtful accounts of $5.4 million as at December 31, 2011 (2010 - $4.8 million), is as follows:

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

14. FINANCIAL INSTRUMENTS (CONTINUED)

CREDIT RISK (CONTINUED)

	December 31, 2011	December 31, 2010
Not past due	**$ 227.4**	$ 281.9
Past due 0-30 days	**10.4**	15.1
Past due 31-60 days	**0.6**	1.0
Past due 61-90 days	**-**	-
Past due over 91 days	**-**	0.1
Total	**$ 238.4**	$ 298.1

LIQUIDITY RISK

Liquidity risk is the risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments. The Corporation's financial position could be adversely affected if it fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial position of the Corporation, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To mitigate this risk, the Corporation had consolidated authorized lines of credit of $500.0 million (2010 - $500.0 million) as at December 31, 2011, of which $386.8 million (2010 - $277.3 million) was unused. The $500 million syndicated credit facility expires in August 2013. The facility is unsecured and is used for general corporate purposes. The Corporation targets to have, on average, sufficient liquidity to allow it not to access the capital markets for a period of twelve months.

The following summary outlines the Corporation's credit facility.

Credit Facilities	**December 31, 2011**	December 31, 2010
Total credit facility	**$ 500.0**	$ 500.0
Credit facility utilized		
Short-term borrowings	**(65.0)**	(178.0)
Letters of credit outstanding	**(48.2)**	(44.7)
Credit facility available	**$ 386.8**	$ 277.3

The Corporation targets a strong investment-grade credit rating to maintain capital market access at reasonable interest rates. As at December 31, 2010, the Corporation's credit ratings were as follows:

Credit Ratings	**DBRS**	**Moody's**
Commercial paper	R-1 (Low)	-
Secured long-term debt	A	A1
Unsecured long-term debt	A	A3

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

14. FINANCIAL INSTRUMENTS (CONTINUED)

LIQUIDITY RISK (CONTINUED)

A downward change in the credit ratings of the Corporation by one notch on January 1, 2011 would decrease earnings for the year ended December 31, 2011 by $0.2 million (2010 - $0.2 million). The Corporation has existing regulatory deferrals that would absorb the impact of interest rate change as a result of a change in the Corporation's credit ratings.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2011.

Financial Liabilities	**≤ 1 year**	**>1-3 years**	**4-5 years**	**>5 years**	**Total**
Short-term notes	$ 65.0	$ -	$ -	$ -	$ 65.0
Accounts payable and accrued liabilities	303.7	-	-	-	303.7
Long-term debt, including current portion[1]	2.9	5.8	280.7	1,270.0	1,559.4
Interest obligations on long-term debt	105.4	210.9	202.0	1,483.5	2,001.8
	$ 477.0	$ 216.7	$ 482.7	$2,753.5	$ 3,929.9
Derivatives Financial Assets (Liabilities)					
Commodity Contracts	$ (69.5)	$ (12.6)	$ -	$ -	$ (82.1)
Foreign exchange forwards	(4.4)	-	-	-	(4.4)

[1] *Excluding deferred financing costs of $14.0 million.*

MARKET RISK

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in foreign exchange rates or market interest rates.

The Corporation's earnings are not exposed to changes in the US dollar-to-Canadian dollar exchange rate.

FEI's US dollar payments under a contract for the construction of a Customer Information System are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. FEI has entered into a foreign exchange forward contract to hedge this exposure. As at December 31, 2011, a five percent appreciation of the US dollar-to-Canadian dollar exchange rate, as it impacts the measurement of the fair value of the foreign exchange forward contract, in the absence of rate regulation and with all other variables constant, would have increased earnings by $0.2 million for the year ended December 31, 2011 and a five percent depreciation of the US dollar-to-Canadian dollar exchange rate would have decreased earnings by $0.2 million for the year ended December 31, 2011.

FEI has regulatory approval to defer any increase or decrease in the fair value of the foreign exchange forward contract for recovery from, or refund to, customers in future rates. Therefore, any change in fair value would have impacted regulatory assets or liabilities rather than earnings.

14. FINANCIAL INSTRUMENTS (CONTINUED)

MARKET RISK (CONTINUED)

The Corporation's natural gas derivatives are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The following sensitivity analysis estimates the impact on the fair value of natural gas commodity swaps and options of a five per cent appreciation and depreciation of the US dollar-to-Canadian dollar exchange rate, with all other variables remaining constant, for the year ended December 31, 2011. A five per cent appreciation of the US dollar-to-Canadian dollar exchange rate would change the fair value of natural gas commodity swaps and options by moving the fair value further out of the money by $0.1 million (2010 - $0.1 million) for the year ended December 31, 2011. This would result in an increase in "Accounts payable and accrued liabilities" and "Current Assets: Current portion of rate stabilization accounts." A five per cent depreciation of the US dollar-to-Canadian dollar exchange rate would change the fair value of natural gas commodity swaps and options by reducing the Corporation's out of the money position by $0.1 million (2010 - $0.1 million) for the year ended December 31, 2011. This would result in a decrease in "Accounts payable and accrued liabilities" and "Current Assets: Current portion of rate stabilization accounts."

The Corporation is exposed to interest rate risk associated with short-term borrowings and floating rate debt. The Corporation may enter into interest rate swaps to help reduce this risk. Approximately 100 per cent of the Corporation's operating facility is subject to interest rate risk while none of its long-term debt is subject to interest rate risk. A 100 basis point increase in interest rates would decrease earnings for the year ended December 31, 2011 by $1.0 million (2010 - $1.0 million) if not for the fact that the Corporation has existing regulatory deferrals that would absorb the impact of such interest rate changes.

NATURAL GAS COMMODITY PRICE RISK

The Corporation is exposed to risks associated with changes in the market price of natural gas as a result of the natural gas derivatives. The Corporation's price risk management strategy covers a term of 36 months and aims to (i) improve the likelihood that natural gas prices remain competitive with electricity rates, (ii) dampen price volatility on customer rates and (iii) reduce the risk of regional price disconnects.

In the accompanying Balance Sheet at December 31, 2011, the balance of $68.5 million (2010 - $96.3 million) captioned as "Current Assets: Current portion of rate stabilization accounts" includes a $86.8 million (2010 - $120.4 million) mark-to-market adjustment representing unrealized losses on hedges that are recoverable from customers through rates.

The Corporation's exposure to market risk includes forward-looking statements and represents an estimate of possible changes in fair value that would occur assuming hypothetical future movements in commodity prices. The Corporation's views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated, based on actual fluctuations in interest rates or commodity prices and the timing of transactions.

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

14. FINANCIAL INSTRUMENTS (CONTINUED)

NATURAL GAS COMMODITY PRICE RISK (CONTINUED)

The following sensitivity analysis estimates the impact on the fair value of natural gas commodity swaps and options of a one dollar change in the value of the underlying price of natural gas, with all other variables remaining constant, for the year ended December 31, 2011. This analysis is for illustrative purposes only, as in practice market rates rarely change in isolation. If the price of natural gas decreased by one dollar per GJ, the change in the fair value of natural gas commodity swaps and options would be to move further out of the money by $45.6 million (2010 - $44.0 million) for the year ended December 31, 2011. This would result in an increase in "Accounts payable and accrued liabilities" and "Current Assets: Current portion of rate stabilization accounts." If the price of natural gas increased by one dollar per GJ, the change in the fair value of natural gas commodity swaps and options would be to reduce the Corporation's out of the money position by $45.6 million (2010 - $45.2 million) for the year ended December 31, 2011. This would result in a decrease in "Accounts payable and accrued liabilities" and "Current Assets: Current portion of rate stabilization accounts."

CAPITAL MANAGEMENT

The Corporation's principal business of regulated gas distribution requires ongoing access to capital in order to allow it to fund the maintenance and expansion of infrastructure. The Corporation has secured a multi-year committed credit facility to support short-term financing of capital expenditures and seasonal working capital requirements. The committed credit facility is available for general corporate purposes.

The Corporation maintains a capital structure in line with the deemed capital structure approved by the BCUC which up to December 31, 2009 was 35.01 per cent equity financing of rate base. Effective January 1, 2010, the deemed capital structure approved by the BCUC is 40 per cent equity financing of rate base for the Corporation.

The consolidated capital structure of the Corporation is presented in the following table.

	December 31, 2011	**(%)**	December 31, 2010	(%)
Total debt and capital lease obligations[1]	**$ 1,593.2**	**60.3**	$ 1,607.5	61.1
Shareholders' equity	**1,049.5**	**39.7**	1,022.5	38.9
Total	**$ 2,642.7**	**100.0**	$ 2,630.0	100.0

1 Includes long term debt, including current portion, and short term borrowings, net of cash and cash equivalents

Certain of the Corporation's long-term debt obligations have issuance tests that prevent the Corporation from incurring additional long term debt unless the interest coverage is at least two times available net earnings. In addition, the Corporation's credit agreement requires maintenance of certain financial covenants such as a maximum percentage of debt to equity. As at December 31, 2011 and 2010, the Corporation was in compliance with these covenants.

The Corporation's credit ratings and credit facilities are disclosed under "Liquidity Risk".

15. RELATED PARTY TRANSACTIONS

a) The Corporation received $3.5 million in 2011 (2010 – $3.5 million) from FortisBC Energy (Vancouver Island) Inc. (FEVI), a subsidiary of FortisBC Holdings Inc. (FortisBC Holdings), for transporting gas through the Corporation's pipeline system. This income is included in natural gas transmission and distribution revenues on the consolidated statements of earnings and comprehensive earnings.

b) The Corporation paid approximately $49.4 million (2010 - $48.1 million) during the year ended December 31, 2011 for customer care and billing services to a limited partnership in which FortisBC Holdings owns a 30 per cent interest. These costs are included in operation and maintenance expenses on the consolidated statements of earnings and comprehensive earnings.

c) The Corporation reimbursed its parent, FortisBC Holdings for management services under a shared-services agreement totalling $9.6 million (2010 – $9.6 million) for the year ended December 31, 2011. The management services fee is included in operation and maintenance expenses on the consolidated statements of earnings and comprehensive earnings.

d) The Corporation charged $9.4 million (2010 – $9.6 million) to affiliated companies for management services during the year ended December 31, 2011. The management services fee is included in operation and maintenance expenses on the consolidated statements of earnings and comprehensive earnings.

e) The Corporation's indirect parent, Fortis Inc., grants stock options to certain employees of the Corporation under its stock option plans. For the year ended December 31, 2011, the Corporation was charged, and recorded an expense of $0.7 million (2010 - $0.7 million) for the fair value of the stock compensation granted by Fortis Inc. The stock option expense is included in operation and maintenance expenses on the consolidated statements of earnings and comprehensive earnings.

f) Included in accounts receivable is $1.4 million (2010 - $3.0 million) owed to the Corporation by affiliated companies. The amounts are unsecured and non-interest bearing.

g) The Corporation was charged $12.0 million for the year ended December 31, 2011 by FEVI for storing gas at the Mt. Hayes LNG storage facility which became operational in April 2011. This cost is included in Current Liabilities: Current portion of rate stabilization accounts on the consolidated balance sheet.

h) For the year ended December 31, 2011 the Corporation was charged $1.9 million (2010 - $1.2 million) by FortisBC Inc. (an indirect subsidiary of Fortis Inc.) for electricity purchases and corporate management services. For the year ended December 31, 2011 the Corporation charged $1.2 million (2010 - $0.5 million) to FortisBC Inc. for rent and labour charges. These charges are included in operation and maintenance expenses on the consolidated statements of earnings and comprehensive earnings.

Related party transactions are recorded at the exchange amount.

(Tabular amounts in millions of Canadian dollars, unless otherwise noted)

16. COMMITMENTS AND CONTINGENCIES

The Corporation has entered into operating leases for certain building space and natural gas transmission and distribution assets. In addition, the Corporation enters into gas purchase contracts that represent future purchase obligations.

The following table sets forth the Corporation's operating leases, gas purchase obligations and employee benefit plan contributions due in the years indicated:

	Operating leases	Purchase obligations	Employee benefit plans	Total
2012	$ 16.4	$ 157.8	$ 11.8	$ 186.0
2013	16.0	73.9	9.2	99.1
2014	15.6	45.5	-	61.1
2015	15.3	-	-	15.3
2016	15.1	-	-	15.1
Thereafter	59.5	-	-	59.5
	$ 137.9	$ 277.2	$ 21.0	$ 436.1

Gas purchase contract commitments are based on gas commodity indices that vary with market prices. The amounts disclosed reflect index prices that were in effect at December 31, 2011. The employee benefit plan contributions have been estimated up to the date of the next actuarial valuation for each plan unless the valuation falls in the next twelve months then the Corporation has provided for an estimate of the contributions. Employee benefit plan contributions beyond the date of the next actuarial valuation cannot be accurately estimated.

In addition to the items in the table above, the Corporation has issued commitment letters to customers to provide Energy Efficiency and Conservation (EEC) funding under the EEC Program approved by the BCUC. As at December 31, 2011, the Corporation had issued $3.8 million of commitment letters to customers.

Attachment 7b

FILED CONFIDENTIALLY